UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2020

OR

☐ **TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _________ to _________

Commission File Number 001-19514

Gulfport Energy Corporation
(Exact Name of Registrant As Specified in Its Charter)

Delaware	**73-1521290**
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification Number)
3001 Quail Springs Parkway	
Oklahoma City, Oklahoma	**73134**
(Address of Principal Executive Offices)	(Zip Code)

(405) 252-4600
(Registrant Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

None[(1)]

(1) On November 27, 2020, our common stock was suspended from trading on the NASDAQ Stock Market LLC ("NASDAQ"). On November 30, 2020, our common stock began trading on the OTC Pink Marketplace maintained by the OTC Markets Group, Inc. under the symbol "GPORQ". On February 2, 2021, NASDAQ filed a Form 25 delisting our common stock from trading on NASDAQ, which delisting became effective 10 days after the filing of the Form 25. In accordance with Rule 12d2-2 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), the de-registration of our common stock under section 12(b) of the Exchange Act became effective on February 12, 2021.

Securities registered pursuant to Section 12(g) of the Act:

Common Stock
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (Section 232.405 of this chapter) during the preceding 12 months (or such shorter period that the registrant was required to submit such files).
Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐
Smaller reporting company ☐ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of our common stock held by non-affiliates on June 30, 2020 was approximately $ 174.4 million. As of February 22, 2021, there were 160,762,186 shares of our $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Gulfport Energy Corporation's Proxy Statement for the 2021 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

GULFPORT ENERGY CORPORATION
TABLE OF CONTENTS

DEFINITIONS

Unless the context otherwise indicates, references to “us,” “we,” “our,” “ours,” “Gulfport,” the “Company” and “Registrant” refer to Gulfport Energy Corporation and its consolidated subsidiaries. All monetary values, other than per unit and per share amounts, are stated in thousands of U.S. dollars unless otherwise specified. In addition, the following are other abbreviations and definitions of certain terms used within this Annual Report on Form 10-K:

2005 Plan. 2005 Stock Incentive Plan.

2013 Plan. 2013 Restated Stock Incentive Plan.

2019 Plan. 2019 Amended and Restated Stock Incentive Plan.

2020 Plan. 2020 Incentive Plan, which provides incentive awards for select employees of the Company that were tied to the achievement of one or more performance goals relating to certain financial and operational metrics over a period of time.

2023 Notes. 6.625% Senior Notes due 2023.

2024 Notes. 6.000% Senior Notes due 2024.

2025 Notes. 6.375% Senior Notes due 2025.

2026 Notes. 6.375% Senior Notes due 2026.

ASC. Accounting Standards Codification.

ASU. Accounting Standards Update.

Bankruptcy Code. Chapter 11 of Title 11 of the United States Code.

Bankruptcy Court. The United States Bankruptcy Court for the Southern District of Texas.

Bankruptcy Rules. The Federal Rules of Bankruptcy Procedure.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

Bcfe. One billion cubic feet of natural gas equivalent.

Btu. British thermal unit, which represents the amount of energy needed to heat one pound of water by one degree Fahrenheit and can be used to describe the energy content of fuels.

Building Loan. Loan agreement for our corporate headquarters scheduled to mature in June 2025.

Chapter 11 Cases. Voluntary petitions filed on November 13, 2020 by Gulfport Energy Corporation, Gator Marine, Inc., Gator Marine Ivanhoe, Inc., Grizzly Holdings, Inc., Gulfport Appalachia, LLC, Gulfport Midcon, LLC, Gulfport Midstream Holdings, LLC, Jaguar Resources LLC, Mule Sky LLC, Puma Resources, Inc. and Westhawk Minerals LLC.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas, oil and NGL.

DD&A. Depreciation, depletion and amortization.

Debtors. Collectively, Gulfport Energy Corporation, Gator Marine, Inc., Gator Marine Ivanhoe, Inc., Grizzly Holdings, Inc., Gulfport Appalachia, LLC, Gulfport Midcon, LLC, Gulfport Midstream Holdings, LLC, Jaguar Resources LLC, Mule Sky LLC, Puma Resources, Inc. and Westhawk Minerals LLC.

Developed Acreage. The number of acres allocated or assignable to productive wells or wells capable of production.

Development well. A well drilled within the proved area of a natural gas or crude oil reservoir to the depth of a stratigraphic horizon known to be productive.

DIP Credit Facility. Senior secured superpriority debtor-in-possession revolving credit facility in an aggregate principal amount of $262.5 million.

Dry Hole. A well that does not produce crude oil and/or natural gas in economically producible quantities.

Exploratory Well. A well drilled to find crude oil or natural gas in an unproved area, to find a new reservoir in an existing field previously found to be productive of crude oil or natural gas in another reservoir, or to extend a known reservoir beyond the proved area.

Grizzly. Grizzly Oil Sands ULC.

Grizzly Holdings. Grizzly Holdings Inc.

Gross Acres or Gross Wells. Refers to the total acres or wells in which a working interest is owned.

Guarantors. All existing consolidated subsidiaries that guarantee the Company's revolving credit facility or certain other debt.

Held By Production. Refers to an oil and gas lease continued into its secondary term for so long as a producing oil and/or gas well is located on any portion of the leased premises or lands pooled therewith.

Horizontal Drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled horizontally within a specified interval.

LIBOR. London Interbank Offered Rate.

LOE. Lease operating expenses.

MBbl. One thousand barrels of crude oil, condensate or natural gas liquids.

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet of natural gas equivalent.

MMBbl. One million barrels of crude oil, condensate or natural gas liquids.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

MMcfe. One million cubic feet of natural gas equivalent.

Natural Gas Liquids (NGL). Hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption or other methods in gas processing or cycling plants. Natural gas liquids primarily include ethane, propane, butane, isobutene, pentane, hexane and natural gasoline.

Net Acres or Net Wells. Refers to the sum of the fractional working interests owned in gross acres or gross wells.

Net Revenue Interest (NRI). An interest in an oil and natural gas property entitling the owner to a share of oil, natural gas or NGL production.

NYMEX. New York Mercantile Exchange.

OCC. Oklahoma Corporation Commission.

Petition Date. November 13, 2020.

Plan. Prearranged joint plan of reorganization under the Restructuring Support Agreement.

Pre-Petition Revolving Credit Facility. Senior secured revolving credit facility, as amended, with The Bank of Nova Scotia as the lead arranger and administrative agent and certain lenders from time to time party thereto with a maximum facility amount of $580 million.

Productive Well. A well found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Proved Developed Reserves (PDPs). Reserves expected to be recovered through existing wells with existing equipment and operating methods.

Proved Undeveloped Reserves (PUDs). Proved reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for completion.

PV-10. Present net value of estimated future net revenues, discounted at 10%.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Restructuring. Restructuring contemplated under the Restructuring Support Agreement including equitizing a significant portion of our pre-petition indebtedness and rejecting or renegotiating certain contracts.

Royalty Interest. Refers to the ownership of a percentage of the resources or revenues produced from a crude oil or natural gas property. A royalty interest owner does not bear exploration, development, or operating expenses associated with drilling and producing a crude oil or natural gas property.

RSA. Restructuring Support Agreement.

SCOOP. Refers to the South Central Oklahoma Oil Province, a term used to describe a defined area that encompasses many of the top hydrocarbon producing counties in Oklahoma within the Anadarko basin. The SCOOP play mainly targets the Devonian to Mississippian aged Woodford, Sycamore and Springer formations. Our acreage is primarily in Garvin, Grady and Stephens Counties.

SEC. The United States Securities and Exchange Commission.

*Section 382.*Internal Revenue Code Section 382.

Senior Notes. Collectively, the 6.625% Senior Notes due 2023, the 6.000% Senior Notes due 2024, the 6.375% Senior Notes due 2025 and the 6.375% Senior Notes due 2026.

Standardized Measure. Standardized measure of discounted future net cash flows.

Tcfe. One trillion cubic feet of natural gas equivalent.

Undeveloped Acreage. Lease or mineral acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and/or natural gas.

USEPA. United States Environmental Protection Agency.

Utica. Refers to the hydrocarbon bearing rock formation located in the Appalachian Basin of the United States and Canada. Our acreage is located primarily in Belmont, Harrison, Jefferson and Monroe Counties in Eastern Ohio.

Working Interest (WI). The operating interest which gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

FORWARD-LOOKING STATEMENTS

This Form 10-K may include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. These statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In some cases, you can identify forward looking statements by terms such as “may,” “will,” “should,” “could,” “would,” “expects,” “plans,” “anticipates,” “intends,” “believes,” “estimates,” “projects,” “predicts,” “potential” and similar expressions intended to identify forward-looking statements. All statements, other than statements of historical facts, included in this Form 10-K that address activities, events or developments that we expect or anticipate will or may occur in the future, including such things as the potential effects of the Chapter 11 Cases on our operations, management, and employees, our ability to consummate the restructuring, our ability to continue as a going concern, the expected impact of the COVID-19 pandemic on our business, our industry and the global economy, estimated future net revenues from oil and gas reserves and the present value thereof, future capital expenditures (including the amount and nature thereof), business strategy and measures to implement strategy, competitive strength, goals, expansion and growth of our business and operations, plans, references to future success, reference to intentions as to future matters and other such matters are forward-looking statements.

These forward-looking statements are largely based on our expectations and beliefs concerning future events, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors relating to our operations and business environment, all of which are difficult to predict and many of which are beyond our control.

Although we believe our estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this Form 10-K are not guarantees of future performance, and we cannot assure any reader that those statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the factors listed in Item 1A. “*Risk Factors*” and Item 7. “*Management's Discussion and Analysis of Financial Condition and Results of Operations*” sections and elsewhere in this Form 10-K. All forward-looking statements speak only as of the date of this Form 10-K.

All forward-looking statements, expressed or implied, included in this Annual Report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report.

Investors should note that we announce financial information in SEC filings. We may use the Investors section of our website (www.gulfportenergy.com) to communicate with investors. It is possible that the financial and other information posted there could be deemed to be material information. The information on our website is not part of this Annual Report on Form 10-K.

SUMMARY RISK FACTORS

Chapter 11 Cases Risks

- The Chapter 11 Cases may have a material adverse impact on our business, financial condition, results of operations and cash flows. In addition, the consummation of a plan of reorganization will result in the cancellation and discharge of our equity securities, including our common stock.
- Delays in the Chapter 11 Cases may increase the risk of us being unable to reorganize our business and emerge from bankruptcy and increase our costs associated with the bankruptcy process.
- We are subject to certain risks and uncertainties if our exclusive right to file a plan of reorganization is terminated.
- Adverse publicity in connection with the Chapter 11 Cases or otherwise could negatively affect our businesses.
- Trading in our common stock during the Chapter 11 Cases is highly speculative and poses substantial risks.
- The RSA is subject to significant conditions and milestones that may be difficult for us to satisfy.
- A plan of reorganization may not become effective.
- The audited consolidated financial statements included in this Form 10-K for the period ended December 31, 2020 contain disclosures that express substantial doubt about our ability to continue as a going concern.
- Upon emergence from bankruptcy, the composition of our Board of Directors may change significantly.

Financial, Liquidity and Commodity Price Risks

- Natural gas, oil and NGL prices fluctuate widely, and lower prices for an extended period of time are likely to have a material adverse effect on our business
- Our commodity price risk management activities may limit the benefit we would receive from increases in commodity prices, may require us to provide collateral for derivative liabilities and involve risk that our counterparties may be unable to satisfy their obligations to us.
- We have a significant amount of indebtedness. Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects.
- Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase.
- We have significant capital needs, and our ability to access the capital and credit markets to raise capital on favorable terms is limited by our debt level and industry conditions.
- If we are unable to generate enough cash flow from operations to service our indebtedness or are unable to use future borrowings to refinance our indebtedness or fund other capital needs, in each case following our restructuring, we may have to undertake alternative financing plans, which may have onerous terms or may be unavailable.
- Our development, acquisition and exploration operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a loss of properties and a decline in our oil and natural gas reserves.
- Under our method of accounting for oil and natural gas properties, declines in commodity prices may result in impairment of asset value.
- A change of control could limit our use of net operating losses to reduce future taxable income.

Industry, Business and Operational Risks

- The oil and gas exploration and production industry is very competitive, and some of our competitors have greater financial and other resources than we do.
- If we are not able to replace reserves, we may not be able to sustain production.
- The actual quantities of and future net revenues from our proved reserves may be less than our estimates.
- Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.
- Part of our strategy involves drilling in existing or emerging shale plays using the latest available horizontal drilling and completion techniques; therefore, the results of our planned exploratory drilling in these plays are subject to risks associated with drilling and completion techniques and drilling results may not meet our expectations for reserves or production.
- Our undeveloped acreage must be drilled before lease expiration to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.
- Oil and natural gas operations are uncertain and involve substantial costs and risks. Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits.

- We are not the operator of all of our oil and natural gas properties and therefore are not in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves on such properties.
- Oil and natural gas production operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water. Our ability to produce natural gas, oil and NGL economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our operations or are unable to dispose of or recycle the water we use economically and in an environmentally safe manner.
- Substantially all of our producing properties are located in Eastern Ohio and Oklahoma, making us vulnerable to risks associated with operating in these regions.
- The loss of one or more of the purchasers of our production could adversely affect our business, results of operations, financial condition and cash flows.
- The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies, oilfield services or personnel may restrict our operations.
- Our operations may be adversely affected by pipeline, trucking and gathering system capacity constraints and may be subject to interruptions that could adversely affect our cash flow.
- Our forecasted production is less than our firm transportation commitment levels under our firm transportation contracts due to decreased developmental activities, which will result in excess firm transportation costs and may have a material adverse effect on our operations.
- The outbreak of the novel coronavirus, or COVID-19, has affected and may materially adversely affect, and any future outbreak of any other highly infectious or contagious diseases may materially adversely affect, our operations, financial performance and condition, operating results and cash flows.
- A deterioration in general economic, business or industry conditions would have a material adverse effect on our results of operations, liquidity and financial condition.
- Terrorist activities could materially and adversely affect our business and results of operations.
- Cyber-attacks targeting systems and infrastructure used by the oil and gas industry and related regulations may adversely impact our operations and, if we are unable to obtain and maintain adequate protection for our data, our business may be harmed.

Legal and Regulatory Risks

- The ultimate outcome of pending legal and governmental proceedings is uncertain, and there are significant costs associated with these matters.
- Decisions by the Ohio Supreme Court interpreting the Ohio Dormant Mineral Act relating to preservation of mineral rights by surface owners could require certain curative efforts to vest title in a portion of our leasehold acreage, increase our leasehold expenses, subject us to payment of additional royalties or result in the loss of some of our leasehold acreage in Ohio.
- We are subject to extensive governmental regulation and ongoing regulatory changes, which could adversely impact our business.
- Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could have a material adverse effect on our business.
- Future U.S. and state tax legislation may adversely affect our business, results of operations, financial condition and cash flow.
- Our business is subject to complex and evolving laws and regulations regarding privacy and data protection.
- We may have material liability related to plugging and abandonment, reclamation, civil lawsuits and regulatory fines related to our divested Louisiana assets.

PART I

ITEM 1. BUSINESS

Our Business

A Delaware corporation formed in 1997, we are an independent natural gas-weighted exploration and production company with assets primarily located in the Appalachia and Anadarko basins. Our corporate strategy is focused on the economic development of our asset base in an effort to generate sustainable free cash flow. Our principal properties are located in Eastern Ohio, where we target development in the Utica formation, and Central Oklahoma where we target development in the SCOOP Woodford and Springer formations.

As of December 31, 2020, we had 2.6 Tcfe of proved reserves with a standardized measure of discounted future net cash flows of $540.0 million and a PV-10 of $540.0 million. See "*Definitions*" above for our definition of PV-10 (a non-GAAP financial measure) and "*Oil, Natural Gas and NGL Reserves*" below for a reconciliation of our standardized measure of discounted future net cash flows (the most directly comparable GAAP measure) to PV-10.

Information About Us

Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are made available free of charge on the Investor Relations page of our website at www.gulfportenergy.com as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. From time to time, we also post announcements, updates, events, investor information and presentations on our website in addition to copies of our recent news releases. Information contained on our website, or on other websites that may be linked to our website, is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code

On November 13, 2020, Gulfport Energy Corporation, Gator Marine, Inc., Gator Marine Ivanhoe, Inc., Grizzly Holdings, Inc., Gulfport Appalachia, LLC, Gulfport Midcon, LLC, Gulfport Midstream Holdings, LLC, Jaguar Resources LLC, Mule Sky LLC, Puma Resources, Inc. and Westhawk Minerals LLC filed voluntary petitions of relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the Southern District of Texas. The Chapter 11 Cases are being administered jointly under the caption *In re Gulfport Energy Corporation, et al.*, Case No. 20-35562 (DRJ). Information about our Chapter 11 cases is available at our website (www.gulfportenergy.com).

We are currently operating our business and managing our properties as debtors in possession pursuant to sections 1107(a) and 1108 of the Bankruptcy Code. On November 14, 2020, the Bankruptcy Court entered an order authorizing the joint administration and procedural consolidation of these Chapter 11 Cases pursuant to Bankruptcy Rule 1015(b). At the first day hearing on November 16, 2020, the Bankruptcy Court granted certain requested relief enabling us to conduct our business activities in the ordinary course, including, among other things and subject to the terms and conditions of such orders, authorizing us to pay employee wages and benefits, pay taxes and certain governmental fees and charges, continue to operate our cash management system in the ordinary course, remit funds we hold from time to time for the benefit of third parties (such as royalty owners), and pay the pre-petition claims of certain of our vendors that hold liens under applicable non-bankruptcy law. For goods and services provided following the Petition Date, we are permitted and intend to pay vendors in the ordinary course.

Subject to certain exceptions provided for in section 362 of the Bankruptcy Code, all judicial and administrative proceedings against us or our property were automatically enjoined, or stayed, as of the Petition Date. In addition, the filing of new judicial or administrative actions against us or our property for claims arising prior to the date on which our Chapter 11 Cases were filed were automatically enjoined. This prohibits, for example, our lenders or noteholders from pursuing claims for defaults under our debt agreements and our contract counterparties from pursuing claims for defaults under our contracts. Accordingly, unless the Bankruptcy Court agrees to lift the automatic stay, all of our pre-petition liabilities and obligations should be settled or compromised under the Bankruptcy Code as part of our Chapter 11 proceedings.

Our operations and ability to execute our business remain subject to the risks and uncertainties described in Item 1A.“Risk Factors”. In addition, our assets, liabilities, capital structure, shareholders, officers and directors could change materially because of our Chapter 11 Cases. In addition, the description of our operations, properties and capital plans included in this

Annual Report on Form 10-K may not accurately reflect our operations, properties and capital plans after we emerge from Chapter 11.

Business Strategy

Gulfport aims to create sustainable value through the development of our significant resource plays in the Utica and SCOOP operating areas. Our strategy is to develop our assets in a manner that generates sustainable cash flow and improves margins and operating efficiencies, while maintaining exceptional environmental and safety performance. To accomplish these goals, we allocate capital expenditures to projects we believe offer the highest rate of return and we deploy leading drilling and completion techniques and technologies in our development efforts.

As noted above, we are currently engaged in an in-court restructuring process to improve our balance sheet strength, cost structure and financial strength and flexibility.

Operating Areas

We focus our development and production activities in the geographic operating areas described below.

Utica - The Utica is a hydrocarbon bearing rock formation located in the Appalachian Basin of the United States and Canada. We have approximately 193,000 net reservoir acres located primarily in Belmont, Harrison, Jefferson and Monroe Counties in Eastern Ohio where the Utica ranges in thickness from 600 to over 750 feet. During the fourth quarter of 2020 we produced approximately 887 MMcfe per day net to our interests in this area and accounts for approximately 82% of our total production.

SCOOP - The SCOOP, or South Central Oklahoma Oil Province, is a defined area that encompasses many of the top hydrocarbon producing counties in Oklahoma within the Anadarko basin. The SCOOP play mainly targets the Devonian to Mississippian aged Woodford, Sycamore and Springer formations. We have approximately 73,000 net reservoir acres (comprised of approximately 40,000 in the Woodford formation and approximately 33,000 in the Springer formation) located primarily in Garvin, Grady and Stephens Counties. The Woodford Shale across our position ranges in thickness from 200 to over 400 feet and directly overlies the Hunton Limestone and underlies the Sycamore formation, both of which are also locally productive reservoirs. The Sycamore formation consists of hydrocarbon-bearing interbedded shales and siliceous limestones ranging in thickness from 150 to over 450 feet and is overlain by the Caney Shale. The Springer formation across our position is comprised of a series of lenticular sand and shale units. The primary targets are a series of porous, low clay and organic-rich packages within the Goddard Shale member ranging in thickness from 50 to over 250 feet. During the fourth quarter of 2020, we produced approximately 189 MMcfe per day net to our interests in this area and accounts for approximately 18% of our total production.

Additional Properties - In addition to our core properties discussed above, we also own working interests and overriding royalty interest in various fields including the Bakken formation in North Dakota that account for less than 1% of our total production and proved reserves.

Drilling Activity

The following table sets forth information with respect to operated wells drilled during the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return.

	2020		2019		2018	
	Gross	Net	Gross	Net	Gross	Net
Recompletions:						
Productive	—	—	—	—	47	47
Dry	—	—	—	—	—	—
Total	—	—	—	—	47	47
Development:						
Productive	26	24.4	25	22.4	34	30
Dry	—	—	—	—	—	—
Total	26	24.4	25	22.4	34	30
Exploratory:						
Productive	—	—	1	0.8	2	1.5
Dry	—	—	—	—	—	—
Total	—	—	1	0.8	2	1.5

The following table presents activity by operating area for the year ended December 31, 2020:

Field	Operated				Non-Operated			
	Drilled		Turned to Sales		Drilled		Turned to Sales	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Utica(1)	16	16.0	25	23.8	—	—	—	—
SCOOP(2)	10	8.4	4	3.8	19	0.05	12	0.04
Total	26	24.4	29	27.6	19	0.05	12	0.04

(1) Of the 16 gross wells we drilled in 2020, nine were completed as producing wells and seven were in various stages of completion as of December 31, 2020.
(2) Of the 10 gross wells we drilled in 2020, zero were completed as producing wells and 10 were in various stages of completion as of December 31, 2020.

Acreage

The following table presents our total gross and net productive and non-productive wells, expressed separately for oil and gas, and the total gross and net developed and undeveloped acres as of December 31, 2020.

Field	Average NRI/WI Percentages	Productive Oil Wells		Productive Gas Wells		Non-Productive Oil Wells		Non-Productive Gas Wells		Developed Acreage		Undeveloped Acreage	
		Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Utica	46.78/57.29	146	42.1	501	328.7	2	0.7	11	6.6	120,699	93,598	106,418	99,265
SCOOP	24.43/30.32	105	18.3	508	163.2	7	1.0	33	15.5	49,325	34,421	8,294	5,941
Other	Various	14	0.2	9	—	—	—	—	—	1,021	395	4,145	1,021
Overrides/Royalty Non-operated	0.16/0.0	459	—	86	—	2	—	1	—	—	—	—	—
Total		724	60.6	1,104	491.9	11	1.7	45	22.1	171,045	128,414	118,857	106,227

Of our leases that are not held by production, most have a three- to five-year primary term, many of which include options to extend the primary term. We manage lease expirations to ensure that we do not experience unintended material expirations. Our leasehold management efforts include scheduling our operations to establish production in paying quantities in order to hold leases prior to the expiration dates, paying the prescribed lease extension payments, planning non-core divestitures or strategic acreage trades with other operators to high-grade our lease inventory and letting some leases expire that are no longer part of our development plans. The following table sets forth the potential expiration periods of gross and net undeveloped leasehold acres as of December 31, 2020.

	Undeveloped Acres	
	Gross Acres	Net Acres
Years Ending December 31:		
2021	13,488	12,508
2022	16,438	14,880
2023	16,191	15,290
After 2023	3,291	3,006
Held by production or operations	69,449	60,543
Total	118,857	106,227

Oil, Natural Gas and NGL Reserves

The tables below set forth information as of December 31, 2020, with respect to our estimated proved reserves, the associated estimated future net revenue, the PV-10 and the standardized measure. None of the estimated future net revenue, PV-10 nor the standardized measure are intended to represent the current market value of the estimated oil, natural gas and NGL reserves we own. All of our estimated reserves are located within the United States.

	December 31, 2020			
	Oil (MMBbl)	Natural Gas (Bcf)	NGL (MMBbl)	Total (Bcfe)
Proved developed	7	1,358	22	1,527
Proved undeveloped	7	923	16	1,061
Total proved[(1)]	13	2,281	38	2,588

Totals may not sum or recalculate due to rounding.

	Proved Developed	Proved Undeveloped	Total Proved
		($ in millions)	
Estimated future net revenue[(2)]	$ 679	$ 285	$ 964
Present value of estimated future net revenue (PV-10)[(2)]	$ 504	$ 36	$ 540
Standardized measure[(2)]			$ 540

(1) Utica and SCOOP accounted for approximately 67% and 33%, respectively, of our estimated proved reserves by volume as of December 31, 2020.

(2) Estimated future net revenue represents the estimated future revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions as of December 31, 2020, and assuming commodity prices as set forth below. For the purpose of determining prices used in our reserve reports, we used the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended December 31, 2020. The prices used in our PV-10 measure were $39.54 per barrel and $1.99 per MMBtu, before basis differential adjustments. These prices should not be interpreted as a prediction of future prices, nor do they reflect the value of our commodity derivative instruments in place as of December 31, 2020. The amounts shown do not give effect to non-property-related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization. The present value of estimated future net revenue typically differs from the standardized measure because the former does not include the effects of estimated future income tax expense. There was no effect of estimated future income tax expense as of December 31, 2020, primarily as a result of significant net operating loss carryforwards that can be used to offset income taxes on future taxable income.

Management uses PV-10, which is calculated without deducting estimated future income tax expenses, as a measure of the value of the Company's current proved reserves and to compare relative values among peer companies. We also understand that securities analysts and rating agencies use this measure in similar ways. While estimated future net revenue and the present value thereof are based on prices, costs and discount factors which may be consistent from company to company, the standardized measure of discounted future net cash flows is dependent on the unique tax situation of each individual company. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows or any other measure of a company's financial or operating performance presented in accordance with GAAP.

A reconciliation of the standardized measure of discounted future net cash flows to PV-10 is presented above. Neither PV-10 nor the standardized measure of discounted future net cash flows purport to represent the fair value of our proved oil and gas reserves.

Grizzly had no proved reserves as of December 31, 2020. For further discussion of our interest in Grizzly, see "*Our Equity Investments*" below.

Reserve engineering is a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. See Item 1A. "*Risk Factors*" contained elsewhere in this Form 10-K. We have not filed any estimates of total, proved net oil or gas reserves with any federal authority or agency other than the SEC since the beginning of our last fiscal year.

Changes in Proved Reserves during 2020.

The following table summarizes the changes in our estimated proved reserves during 2020 (in Bcfe):

Proved Reserves, December 31, 2019	**4,528**
Sales of oil and natural gas reserves in place	(75)
Extensions and discoveries	240
Revisions of prior reserve estimates	(1,725)
Current production	(380)
Proved Reserves, December 31, 2020	**2,588**

*Sales of oil and natural gas reserves in place.*These are reductions to proved reserves resulting from the divestiture of minerals in place during a period. During 2020, we sold approximately 74.9 Bcfe of proved oil and natural gas reserves through various sales of our non-operated interests in our Utica assets.

Extensions and discoveries. These are additions to our proved reserves that result from extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery. Extensions of approximately 239.8 Bcfe of proved reserves were primarily attributable to the continued development of our Utica and SCOOP acreage. We added 14 PUD locations in our Utica acreage for 150.6 Bcfe and eight PUD locations in our SCOOP acreage for 87.8 Bcfe. The commodity prices utilized for the 2020 reserves determination as well as our revised five-year development plan focused on generating sustainable cash flow limited our ability to add significant well locations.

Revisions of prior reserve estimates. Revisions represent changes in previous reserve estimates, either upward or downward, resulting from development plan changes, new information normally obtained from development drilling and production history or a change in economic factors, such as commodity prices, operating costs or development costs.

We experienced total downward revisions of 1.7 Tcfe in estimated proved reserves, of which 1,268.4 Bcfe was the result of commodity price changes. Commodity prices experienced volatility throughout 2020 and the 12-month average price for natural gas decreased from $2.58 per MMBtu for 2019 to $1.99 per MMBtu for 2020, the 12-month average price for NGL decreased from $21.25 per barrel for 2019 to $15.40 per barrel for 2020, and the 12-month average price for crude oil decreased from $55.85 per barrel for 2019 to $39.54 per barrel for 2020.

An additional 720.3 Bcfe in downward revisions was a result of the exclusion of 48 PUD locations in our Utica field and 31 PUD locations in our SCOOP field when changes in our schedule moved development of these PUD locations beyond five years of initial booking. The development plan change reflects our commitment to capital discipline and funding future activities within cash flow and ongoing optimization of our development plan.

Positive revisions of 263.8 Bcfe were experienced from a combination of operating and development cost improvements, well performance and working interest changes.

Additional information regarding estimates of proved reserves, proved developed reserves and proved undeveloped reserves at December 31, 2020, 2019 and 2018 and changes in proved reserves during the last three years are contained in the Supplemental Information on Oil and Gas Exploration and Production Activities, or Supplemental Information, in Note 19 of the notes to our consolidated financial statements included in this report.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2020, our proved undeveloped reserves totaled 7 MMBbl of oil, 923 Bcf of natural gas and 16 MMBbl of NGL, for a total of 1,061 Bcfe. Approximately 60% and 40% of our PUD reserves at year-end 2020 were located in Utica and SCOOP, respectively. PUDs will be converted from undeveloped to developed as the applicable wells commence production or there are no material incremental completion capital expenditures associated with such proved developed reserves.

We record PUD reserves only after a development plan has been approved by our senior management and board of directors to complete the associated development drilling within five years from the time of initial booking. The PUD locations identified in our development plan are determined based on an analysis of the information that we have available at that time. After a development plan has been adopted, we may periodically make adjustments to the approved development plan due to events and circumstances that have occurred subsequent to the time the plan was approved. These circumstances may include changes in commodity price outlook and costs, delays in the availability of infrastructure, well permitting delays and new data from recently completed wells.

The following table summarizes the changes in our estimated proved undeveloped reserves during 2020 (in Bcfe):

Proved Undeveloped Reserves, December 31, 2019	**2,544**
Sales of oil and natural gas reserves in place	(74)
Extensions and discoveries	238
Conversion to proved developed reserves	(368)
Revisions of prior reserve estimates	(1,279)
Proved Undeveloped Reserves, December 31, 2020	**1,061**

Sales of oil and natural gas reserves in place. During 2020, we sold approximately 74.2 Bcfe of proved undeveloped oil and natural gas reserves associated with various operated interests, the majority of which were in our Utica field.

Extensions and discoveries. Our extensions of approximately 238.4 Bcfe were primarily attributed to the addition of 14 PUD drilling locations in the Utica field and eight PUD drilling locations in the SCOOP field as a result of our current development plan that refocused some activity within our existing fields. The commodity prices utilized for the 2020 reserves determination and our revised five-year development plan focused on generating sustainable cash flow limited our ability to add well locations.

Conversion to proved developed reserves. Our 2020 development activities resulted in the conversion of approximately 367.7 Bcfe into proved developed producing reserves, attributable to 25 PUD locations in the Utica field and 10 PUD locations in the SCOOP field. These 35 PUDs represent a conversion rate of 14% for 2020.

Revision of prior reserve estimates. We experienced proved undeveloped downward revisions of 720.3 Bcfe from the exclusion of 48 PUD locations in our Utica field and 31 PUD locations in our SCOOP field due to the SEC five-year development rule. The development plan change, as approved by our senior management and Board of Directors, reflects our commitment to capital discipline, funding future activities within cash flow and ongoing optimization of our development plan.

We also experienced 842.9 Bcfe of downward revisions as a result of commodity price changes. These downward revisions were partially offset by positive revisions of 283.7 Bcfe in estimated proved reserves from a combination of operating and development cost improvements, well performance and working interest changes.

Costs incurred relating to the development of PUDs were approximately $182.3 million in 2020.

All PUD drilling locations included in our 2020 reserve report are scheduled to be drilled within five years of initial booking.

As of December 31, 2020, less than 1% of our total proved reserves were classified as proved developed non-producing.

Reserves Estimation

Reserve estimates for the years ended December 31, 2020, 2019 and 2018 were prepared by Netherland, Sewell & Associates, Inc. ("NSAI") for all of our operating areas.

NSAI is an independent petroleum engineering firm. A copy of the summary reserve reports is included as Exhibit 99.1 to this Annual Report on Form 10-K. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regards to 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. Our independent third-party engineers do not own an interest in any of our properties and are not employed by us on a contingent basis.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with NSAI, our independent reserve engineers, to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves. Our internal technical team members meet with NSAI periodically throughout the year to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to NSAI for our properties such as ownership interest, oil and gas production, well test data, commodity prices, operating and development costs and other considerations, including availability and costs of infrastructure and status of permits. Our Senior Vice President of Reservoir Engineering is primarily responsible for overseeing the preparation of all of our reserve estimates. He is a petroleum engineer with over 20 years of reservoir and operations experience. In addition, our geophysical staff has approximately 85 years combined industry experience and our reservoir staff has approximately 50 years combined experience.

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

- review and verification of historical production, operating, marketing and capital data, which data is based on actual production as reported by us;
- verification of property ownership by our land department;
- preparation of reserve estimates by NSAI in coordination with our experienced reservoir engineers;
- direct reporting responsibilities by our reservoir engineering department to our Chief Operating Officer;
- review by our reservoir engineering department of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new proved undeveloped reserves additions;
- provision of quarterly updates to our board of directors regarding operational data, including production, drilling and completion activity levels and any significant changes in our reserves;
- annual review by our board of directors of our year-end reserve report and year-over-year changes in our proved reserves, as well as any changes to our previously adopted development plans;
- annual review and approval by our senior management and our board of directors of a multi-year development plan;
- annual review by our senior management of adjustments to our previously adopted development plan and considerations involved in making such adjustments; and
- annual review by our board of directors of changes in our previously approved development plan made by senior management and technical staff during the year, including the substitution, removal or deferral of PUD locations.

PV-10 Sensitivities

As noted above, our December 31, 2020 proved reserves were calculated using prices based on the 12-month unweighted arithmetic average of the first-day-of-the month price for the period January through December 2020 of $39.54 per barrel and $1.99 per MMBtu. Holding production and development costs constant, if SEC pricing were $43.49 per barrel and $2.19 per MMBtu, or a 10% increase, this would have resulted in an increase of 181.7 Bcfe of our total proved reserves and a $350 million increase in PV-10 value at December 31, 2020. Holding production and development costs constant, if SEC pricing were $35.59 per barrel and $1.79 per MMBtu, or a 10% decrease, this would have resulted in a decrease of 839.9 Bcfe of our total proved reserves and a $228 million decrease in PV-10 value at December 31, 2020. For each of these scenarios, the 82 PUDs that were economic at SEC pricing were included.

Holding production and development costs constant while assuming SEC pricing closer to the long-term strip pricing of $50.00 per barrel for crude oil and $2.50 per MMBtu for natural gas results in an increase of 1,065 Bcfe of total proved reserves and a $989 million increase in PV-10 value at December 31, 2020. For this scenario, there were an additional 55 PUD locations included that were economic at these prices.

Production, Prices and Production Costs

The following table presents our production volumes during the periods indicated:

	Year Ended December 31, 2020				
	Net Production				
Field	**Natural Gas (MMcf)**	**Oil and Condensate (MBbl)**	**NGL (MBbl)**	**Natural gas equivalents (MMcfe)**	**MMcfe per Day**
Utica	291,133	393	1,077	299,955	820
SCOOP	53,853	1,392	2,886	79,519	217
Other	13	18	1	126	0.3
Total	344,999	1,803	3,964	379,600	1,037

The following table presents our production volumes, average prices received and average production costs during the periods indicated:

	2020	2019	2018
		($ In thousands)	
Natural gas sales			
Natural gas production volumes (MMcf)	344,999	458,178	443,742
Natural gas production volumes (MMcf) per day	943	1,255	1,216
Total sales	$ 671,535	$ 1,135,381	$ 1,318,472
Average price without the impact of derivatives ($/Mcf)	$ 1.95	$ 2.48	$ 2.97
Impact from settled derivatives ($/Mcf)[1]	$ 0.33	$ 0.23	$ (0.04)
Average price, including settled derivatives ($/Mcf)	$ 2.28	$ 2.71	$ 2.93
Oil and condensate sales			
Oil and condensate production volumes (MBbl)	1,803	2,186	2,801
Oil and condensate production volumes (MBbl) per day	5	6	8
Total sales	$ 62,902	$ 117,937	$ 177,793
Average price without the impact of derivatives ($/Bbl)	$ 34.88	$ 53.95	$ 63.48
Impact from settled derivatives ($/Bbl)[2]	$ 25.76	$ 1.86	$ (9.51)
Average price, including settled derivatives ($/Bbl)	$ 60.64	$ 55.81	$ 53.97
NGL sales			
NGL production volumes (MBbl)	3,964	5,074	5,993
NGL production volumes (MBbl) per day	11	14	16
Total sales	$ 66,814	$ 101,448	$ 178,915
Average price without the impact of derivatives ($/Bbl)	$ 16.86	$ 19.99	$ 29.85
Impact from settled derivatives ($/Bbl)	$ (0.04)	$ 2.79	$ (2.30)
Average price, including settled derivatives ($/Bbl)	$ 16.82	$ 22.78	$ 27.55
Natural gas, oil and condensate and NGL sales			
Natural gas equivalents (MMcfe)	379,600	501,742	496,505
Natural gas equivalents (MMcfe) per day	1,037	1,375	1,360
Total sales	$ 801,251	$ 1,354,766	$ 1,675,180
Average price without the impact of derivatives ($/Mcfe)	$ 2.11	$ 2.70	$ 3.37
Impact from settled derivatives ($/Mcfe)	$ 0.42	$ 0.24	$ (0.12)
Average price, including settled derivatives ($/Mcfe)	$ 2.53	$ 2.94	$ 3.25
Production Costs:			
Avg. lease operating expenses ($/Mcfe)	$ 0.14	$ 0.15	$ 0.16
Avg. production taxes ($/Mcfe)	$ 0.05	$ 0.06	$ 0.07
Avg. midstream gathering, processing & firm transportation costs ($/Mcfe)	$ 1.20	$ 1.01	$ 0.98
Total LOE, midstream costs and production taxes ($/Mcfe)	$ 1.39	$ 1.22	$ 1.21

[1] In November 2020, the Company early terminated certain gas sold call options which resulted in a cash payment of $60.2 million.
[2] In April 2020, the Company early terminated certain oil fixed price swaps which resulted in a cash receipt of $40.5 million.

The following table provides a summary of our production, average sales prices and average production costs for oil and gas fields containing 15% or more of our total proved reserves as of December 31, 2020:

	Year Ended December 31,		
	2020	2019	2018
Utica			
Net Production			
Natural gas (MMcf)	291,133	387,473	379,417
Oil (MBbl)	393	247	299
NGL (MBbl)	1,077	1,812	2,700
Total (MMcfe)	299,955	399,828	397,406
Average Price Without the Impact of Derivatives:			
Natural gas ($/Mcf)	$ 1.97	$ 2.28	$ 2.77
Oil ($/Bbl)	$ 33.41	$ 51.11	$ 60.22
NGL ($/Bbl)	$ 18.55	$ 19.74	$ 27.99
Average Lease Operating Expenses ($/Mcfe)	$ 0.13	$ 0.13	$ 0.14

	Year Ended December 31,		
	2020	2019	2018
SCOOP			
Net Production			
Natural gas (MMcf)	53,853	70,669	64,258
Oil (MBbl)	1,392	1,610	1,710
NGL (MBbl)	2,886	3,261	3,292
Total (MMcfe)	79,519	99,891	94,268
Average Price Without the Impact of Derivatives:			
Natural gas ($/Mcf)	$ 1.83	$ 2.13	$ 2.73
Oil ($/Bbl)	$ 35.31	$ 53.32	$ 62.36
NGL ($/Bbl)	$ 16.23	$ 20.13	$ 31.39
Average Lease Operating Expenses ($/Mcfe)	$ 0.18	$ 0.18	$ 0.18

Our Equity Investments

Grizzly Oil Sands. We, through our wholly-owned subsidiary Grizzly Holdings Inc., own a 24.5% interest in Grizzly. As of December 31, 2020, Grizzly had approximately 830,000 net acres under lease in the Athabasca, Peace River and Cold Lake oil sands regions of Alberta, Canada. Grizzly's operations have been suspended since 2016. Additionally, Grizzly had no proved reserves as of December 31, 2020. We elected to cease funding capital calls in 2019, and we have no obligation to fund any of the projects Grizzly is pursuing. Failure to fund capital calls may lead to continued dilution of our equity ownership interest in Grizzly.

Mammoth Energy. As of December 31, 2020, we owned 9,829,548 shares, or approximately 21.5%, of the outstanding common stock of Mammoth Energy Services Inc.

See Note 5 of the notes to our consolidated financial statements included elsewhere in this report for additional information regarding our equity investments.

Marketing

The principal function of our marketing operations is to provide natural gas, oil and NGL marketing services, including securing and negotiating commodity transactions, gathering, hauling, processing and transportation services, contract administration and nomination services for production from Gulfport-operated wells. In addition, we periodically enter into a variety of oil, natural gas and NGL purchase and sale contracts with third parties for various commercial purposes, including risk mitigation and satisfaction of our firm transportation delivery commitments. These marketing activities often enhance the value of our production by aggregating volumes and allowing improved flexibility in relation to deal structure, size and counterparty exposure whether through intermediary markets or direct end markets.

Generally, natural gas and NGL production is sold to purchasers under both spot and term transactions. Oil production is sold under both spot and term transactions with the majority of our sales contracts being shorter term in nature. We have entered into long-term gathering, processing and transportation contracts with various parties that reserve capacity for fixed, determinable quantities of production over specified periods of time. Some contracts require us to make payments for any shortfalls in delivering or transporting minimum volumes under these commitments. See Note 17 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our commitments.

Major Customers

Our total natural gas, oil and NGL revenues, before the effects of hedging, to major customers (purchasers in excess of 10% of total natural gas, oil and NGL sales) for the years ended December 31, 2020, 2019 and 2018 were as follows:

	% of Sales
Year Ended December 31, 2020	
ECO-Energy	12 %
Year Ended December 31, 2019	
Morgan Stanley Capital	14 %
Year Ended December 31, 2018	
BP Energy Company	17 %
ECO-Energy	10 %

Competition

The oil and natural gas industry is intensely competitive, and we compete with many other companies that have greater resources than we have. Competition can negatively impact our ability to successfully source quality vendors and service providers and our ability to secure optimal pipeline access and end markets in which to sell our production. Many of our competitors not only explore for and produce oil and natural gas, but also have midstream and further downstream operations and market a variety of hydrocarbon products on a regional, national or worldwide basis. In addition, oil and natural gas compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include renewable sources such as wind or solar energy in addition to coal and fuel oils. Changes in the availability or price of oil and natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas.

Title to Oil and Natural Gas Properties

It is customary in the oil and natural gas industry to make only a preliminary review of title to undeveloped oil and natural gas leases at the time they are acquired and to obtain more extensive title examinations when acquiring producing properties. In future acquisitions, we will conduct title examinations on material portions of such properties in a manner generally consistent with industry practice. Certain of our oil and natural gas properties may be subject to title defects, encumbrances, easements, servitudes or other restrictions, none of which, in management's opinion, will in the aggregate materially restrict our operations.

Regulation - Environment, Health and Safety

Exploration and Production, Environmental, Health and Safety, and Occupational Laws and Regulations

Our operations are subject to federal, tribal, state, and local laws and regulations. These laws and regulations relate to matters that include, but are not limited to, the following:

- reporting of workplace injuries and illnesses;
- industrial hygiene monitoring;
- worker protection and workplace safety;
- approval or permits to drill and to conduct operations;
- provision of financial assurances (such as bonds) covering drilling and well operations;
- calculation and disbursement of royalty payments and production taxes;
- seismic operations and data;
- location, drilling, cementing and casing of wells;
- well design and construction of pad and equipment;
- construction and operations activities in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species, their habitats, or sites of cultural significance;
- method of completing wells;
- hydraulic fracturing;
- water withdrawal;
- well production and operations, including processing and gathering systems;
- emergency response, contingency plans and spill prevention plans;
- air emissions and fluid discharges;
- climate change;
- use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations;
- surface usage, maintenance, monitoring and the restoration of properties associated with well pads, pipelines, impoundments and access roads;
- plugging and abandoning of wells; and
- transportation of production.

Shortly after taking office in January 2021, President Biden issued a series of executive orders designed to address climate change and requiring agencies to review environmental actions taken by the Trump administration, as well as a memorandum to departments and agencies to refrain from proposing or issuing rules until a departmental or agency head appointed or designated by the Biden administration has reviewed and approved the rule. These executive orders may result in the development of additional regulations or changes to existing regulations. Failure to comply with these laws and regulations can lead to the imposition of remedial liabilities, fines, or criminal penalties or to injunctions limiting our operations in affected areas. Moreover, multiple environmental laws provide for citizen suits which allow environmental organizations to act in the place of the government and sue operators for alleged violations of environmental law. We consider the costs of environmental protection and of safety and health compliance to be necessary, manageable parts of our business. We have been able to plan for and comply with environmental, safety and health laws and regulations without materially altering our operating strategy or incurring significant unreimbursed expenditures. However, based on regulatory trends and increasingly stringent laws, our capital expenditures and operating expenses related to compliance with the protection of the environment, safety and health have increased over the years and may continue to increase. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters. See the Risk Factors described in Item 1A. of this report for further discussion of governmental regulation and ongoing regulatory changes, including with respect to environmental matters.

Our operations are also subject to conservation regulations, including the regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in a unit, the rate of production allowable from oil and gas wells, and the unitization or pooling of oil and gas properties. In the United States, some states allow the forced pooling or integration of tracts to facilitate exploration. Other states rely on voluntary pooling of lands and leases which may make it more difficult to develop oil and gas properties. In addition, federal and state conservation laws generally limit the venting or flaring of natural gas, and state conservation laws impose certain requirements regarding the ratable purchase of production. These regulations often impose additional operational costs to us and can also limit the amounts of oil and gas we can produce from our wells and the number of wells or the locations at which we can drill.

Regulatory proposals in some states and local communities have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. Federal and state agencies have continued to assess the potential impacts of hydraulic fracturing, which could spur further action toward federal, state and/or local legislation and regulation. Further restrictions of hydraulic fracturing could reduce the amount of natural gas, oil and NGL that we are ultimately able to produce in commercial quantities from our properties.

Certain of our U.S. natural gas and oil leases are granted or approved by the federal government and administered by the Bureau of Land Management (BLM) or Bureau of Indian Affairs (BIA) of the Department of the Interior. Such leases require compliance with detailed federal regulations and orders that regulate, among other matters, drilling and operations on lands covered by these leases and calculation and disbursement of royalty payments to the federal government, tribes or tribal members. The federal government has been particularly active in recent years in evaluating and, in some cases, promulgating new rules and regulations regarding competitive lease bidding, venting and flaring, oil and gas measurement and royalty payment obligations for production from federal lands. In addition, on January 20, 2021, the Acting Secretary for the Department of the Interior signed an order effectively suspending new fossil fuel leasing and permitting on federal lands for 60 days. Then on January 27, 2021, President Biden issued an executive order indefinitely suspending new oil and natural gas leases on public lands or in offshore waters pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices. To the extent that the review results in the development of additional restrictions on drilling, limitations on the availability of leases, or restrictions on the ability to obtain required permits, it could have a material adverse impact on our operations.

Permitting activities on federal lands are also subject to frequent delays.

Delays in obtaining permits or an inability to obtain new permits or permit renewals could inhibit our ability to execute our drilling and production plans. Failure to comply with applicable regulations or permit requirements could result in revocation of our permits, inability to obtain new permits and the imposition of fines and penalties.

Operating Hazards and Insurance

The oil and natural gas business involves a variety of operating risks, including the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards such as oil spills, natural gas leaks, ruptures or discharges of toxic gases. If any of these should occur, we could incur legal defense costs and could suffer substantial losses due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, and suspension of operations. Our horizontal and deep drilling activities involve greater risk of mechanical problems than vertical and shallow drilling operations.

We maintain a control of well insurance policy with a $25 million single well limit and a $35 million multiple wells limit that insures against certain sudden and accidental risks associated with drilling, completing and operating our wells. This insurance may not be adequate to cover all losses or exposure to liability. We also carry a $51 million comprehensive general liability umbrella insurance policy. In addition, we maintain a $10 million pollution liability insurance policy providing coverage for gradual pollution related risks and in excess of the general liability policy for sudden and accidental pollution risks. We provide workers' compensation insurance coverage to employees in all states in which we operate. While we believe these policies are customary in the industry, they do not provide complete coverage against all operating risks, and policy limits scale to our working interest percentage in certain situations. In addition, our insurance does not cover penalties or fines that may be assessed by a governmental authority. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows. Our insurance coverage may not be sufficient to cover every claim made against us or may not be commercially available for purchase in the future.

We have prepared and have in place spill prevention control and countermeasure plans for each of our principal facilities in response to federal and state requirements. The plans are reviewed annually and updated as necessary. As required by applicable regulations, our facilities are built with secondary containment systems to capture potential releases. We also own additional spill kits with oil booms and absorbent pads that are readily available, if needed. In addition, we have emergency response companies on retainer. These companies specialize in the clean-up of hydrocarbons as a result of spills, blow-outs and natural disasters, and are on call to us 24 hours a day, seven days a week when their services are needed. We pay these companies a retainer plus additional amounts when they provide us with clean up services. Our aggregate payments for the retainer and clean-up services during each of 2020 and 2019 were immaterial. While these companies have been able to meet our service needs when required from time to time in the past, it is possible that the ability of one or more of them to provide services to us in the future, if and when needed, could be hindered or delayed in the event of a widespread disaster. However, in light of the areas in which we operate and the nature of our production, we believe other companies would be available to us in the event our primary remediation companies are unable to perform. We pay these companies a retainer plus additional amounts when they provide us with clean up services.

Human Capital Management

As of December 31, 2020, we had 256 employees, all of which are non-bargaining. The commodity downturn in late 2019 and the broader economic downturn in 2020 led to significant headcount reductions in late 2019 and 2020. Retaining, replacing and developing talent is very important as our business becomes leaner and we navigate the bankruptcy process. We recognize that even though we are a natural resource company, our most valuable assets are our people. We are passionate about devoting the time, energy and resources required to attract, motivate, retain and develop our employees.

We understand that a workplace environment that embraces diversity and is inclusive of different ideas and perspectives is a healthy environment and one that provides the best solutions to complex challenges. While being an affirmative action employer assists us in locating qualified diversity candidates when filling positions and provides us with a metrics to reflect on how diverse we are, we have recently increased our focus on diversity across the organization including our board of directors. During 2020, our Board of Directors performed an exhaustive search as part of our board refreshment process, adding two highly qualified diversity candidates that add to the background and experience represented on our Board. Gulfport Energy Corporation's diverse independent directors currently constitute 37.5% of the Board. The Board also reviewed and refreshed its Corporate Governance Guidelines and Diversity Principles to promote a more diverse and inclusive board and company. While 2020 was a year in which we added very few new employees, 33% of our newly hired employees were diverse hires. We also initiated a program to ensure that every employee across the company engages in peer-led, small group discussion on diversity topics. The results of these conversations will help shape initiatives in 2021, and it will also mature our diversity and inclusion practices.

We have numerous programs to ensure that our employees and external partners are adequately trained to perform the critical work we do safely and effectively. The programs also focus on respecting the environments where we operate. We utilize in-person training sessions developed by safety experts and supplement these sessions with computer-based modules to support a safety-first mindset in everything we do. We also provide training resources to employees through universities, electronic content services and specialized courses related to our industry through our tuition reimbursement program or third-party providers.

Safety is at the forefront of everything we do. We hold regular safety briefings prior to any significant project and routinely have safety stand-down meetings to highlight potential risks. Every employee is empowered to use their stop-work authority to cease operating if work is being performed in an unsafe manner. We monitor employee safety by establishing annual company-wide key safety metrics tied to leading indicators (i.e., incident reporting and investigations, hazard observations, safety and health meetings) and lagging indicators (i.e., injury rates, preventable motor vehicle accidents). We establish and carefully track key environmental and safety metrics that are a component of every employee's incentive compensation opportunity for 2020.

Executive Officers

David M. Wood, Chief Executive Officer and President

David M. Wood, 64, has served as the Chief Executive Officer and President of the Company, and as a member of our board of directors, since December 2018. Prior to joining the Company, Mr. Wood served as the Chief Executive Officer and Chairman of the Board of Directors of Arsenal Resources LLC ("Arsenal"), a West Virginia-focused natural gas producer and portfolio company of First Reserve Corporation ("First Reserve"), an energy-focused private equity firm, where he most recently served as Chairman of its board of directors and previously held the role of the Chief Executive Officer. Prior to his tenure at Arsenal, Mr. Wood served as a Senior Advisor to First Reserve from 2013 to 2016, serving on several of its portfolio company boards. Prior to his position at First Reserve, Mr. Wood spent more than 17 years at Murphy Oil Corporation (NYSE: MUR) ("Murphy Oil"), a global oil and natural gas exploration and production company, where he served as Chief Executive Officer, President and a member of the board of directors from 2009 to 2012. From 1980 to 1994, Mr. Wood held various senior positions with Ashland Exploration and Production, an oil and natural gas exploration and production company. Mr. Wood began his career as a well-site geologist in Saudi Arabia. Mr. Wood also served on the Board of Directors of the general partner of Crestwood Equity Partners LP (NYSE: CEQP) and its wholly owned subsidiary, Crestwood Midstream Partners LP, an owner and operator of crude oil and natural gas midstream assets. In addition, Mr. Wood served as the Chairman of the Board of Directors for Lilis Energy, Inc. (NYSE: LLEX), an exploration and development company operating in the Delaware Basin. Mr. Wood also served on the Board of Directors of several private oil and natural gas companies, including Deep Gulf Energy LP (prior to its acquisition by Kosmos Energy Ltd.) and Berkana Energy Corp. (when it was majority owned by Murphy Oil). Mr. Wood previously served on the board of directors and as an executive committee member of the American Petroleum Institute. He was also a member of the National Petroleum Council and is a member of the Society of Exploration Geophysicists. Mr. Wood holds a B.S. in Geology from the University of Nottingham in England and completed Harvard University's Advanced Management Program.

Quentin R. Hicks, Executive Vice President and Chief Financial Officer

Quentin R. Hicks, 46, has served as the Executive Vice President and Chief Financial Officer of the Company since August 2019. Prior to joining the Company, Mr. Hicks served as the Executive Vice President and Chief Financial Officer of Halcón Resources Corporation ("Halcón"), a position he held since March 2019, having previously served as Executive Vice President, Finance, Capital Markets and Investor Relations of Halcón since January 2018. Prior to that, Mr. Hicks held various roles at Halcón focused primarily on finance and investor relations. Prior to Halcón, Mr. Hicks worked for GeoResources Inc., where he served as Director of Acquisitions and Financial Planning from 2011 to 2012. From 2004 to 2011, he worked in investment banking with Bear Stearns, Sanders Morris Harris and Madison Williams, where most recently worked as a Director in their energy investment banking practice. Prior to that, Mr. Hicks worked as Manager of Financial Reporting for Continental Airlines. Mr. Hicks began his career in 1998 working as an auditor for Ernst and Young LLP. Mr. Hicks graduated from Texas A&M University with a Bachelor of Business Administration and a Master of Science degree in Accounting. In addition, Mr. Hicks holds a Master of Business Administration degree in Finance from Vanderbilt University and also holds a Certified Public Accountant license from the State of Texas.

Donnie G. Moore, Executive Vice President and Chief Operating Officer

Donnie G. Moore, 56, has served as Executive Vice President, Chief Operating Officer since January 2018. Mr. Moore had also served as Interim Chief Executive Officer of the Company from October 29, 2018, the date our former Chief Executive Officer and President left the Company, to December 18, 2018, the date of the appointment of Mr. Wood as our new Chief Executive Officer and President. From 2007 until December 2017, Mr. Moore worked at Noble Energy, Inc. ("Noble"), an independent oil and gas exploration and production company, where he most recently served as Vice President of Noble's Texas operations for its Eagle Ford and Delaware Basin assets. Prior to that, Mr. Moore held various leadership roles at Noble including Vice President of the Marcellus Business Unit, Manager for Operations of the Wattenberg/DJ Business Unit, Manager of Operations for the Gunflint discovery in the Deepwater Gulf of Mexico and Development Manager for Noble's Mid-Continent and Gulf Coast positions. From 1989 until 2007, Mr. Moore served in a variety of roles with ARCO Oil and Gas Company, Vastar Resources, Inc. and BP America. Mr. Moore holds a Bachelor of Science degree in Petroleum Engineering from Louisiana Tech University.

Patrick K. Craine, Executive Vice President, General Counsel and Corporate Secretary

Patrick K. Craine, 48, has served as Executive Vice President, General Counsel and Corporate Secretary of the Company since May 2019. Mr. Craine has over 20 years of extensive senior-level experience handling a broad range of securities, corporate, regulatory, governance, compliance and litigation matters, with particular expertise in the energy industry. He joined Gulfport from Chesapeake Energy Corporation (NYSE: CHK) ("Chesapeake"), a hydrocarbon exploration company, where he served as Deputy General Counsel – Chief Risk and Compliance Officer from 2013 until 2019. Prior to joining Chesapeake, Mr. Craine was a partner with Bracewell LLP, a global law firm, where his practice focused on securities and corporate regulatory matters and investigations. Before Mr. Craine entered private practice, he served as a lawyer with the SEC and the Financial Industry Regulatory Authority, where he held leadership positions in their Oil and Gas Task Forces. Mr. Craine received his Bachelor of Arts degree, summa cum laude, Phi Beta Kappa, from Wabash College, and his Juris Doctorate, cum laude, from the Southern Methodist University Dedman School of Law.

Michael J. Sluiter, Senior Vice President of Reservoir Engineering

Michael J. Sluiter, 48, has served as Senior Vice President of Reservoir Engineering of the Company since December 2018. Mr. Sluiter joined the Company from Noble Energy, Inc., where he held various engineering positions from 2007 to 2018, including, most recently, as the Permian Basin Business Unit Manager. Mr. Sluiter has over 20 years of experience in unconventional resource development, reservoir engineering, subsurface development, business development and acquisitions, as well as leadership skills, which he developed at Noble Energy, Santos Australia and Santos USA. Mr. Sluiter began his career as a wireline field services engineer for Schlumberger in Thailand. Mr. Sluiter holds a Bachelor of Science degree in Chemical Engineering from the University of Sydney, Australia.

ITEM 1A. RISK FACTORS

Summary of Risk Factors

There are numerous factors that affect our business and operating results, many of which are beyond our control. The following is a summary of significant factors that might cause our future results to differ materially from those currently expected. The risks described below are not the only risks facing our company. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also affect our business operations. If any of these risks actually occur, our business, financial position, operating results, cash flows, reserves or our ability to pay our debts and other liabilities could suffer, the trading price and liquidity of our securities could decline and you may lose all or part of your investment in our securities.

Chapter 11 Cases Risks

The Chapter 11 Cases may have a material adverse impact on our business, financial condition, results of operations and cash flows. In addition, the consummation of a plan of reorganization will result in the cancellation and discharge of our equity securities, including our common stock.

The Chapter 11 Cases could have a material adverse effect on our business, financial condition, results of operations and cash flows. During the pendency of the Chapter 11 Cases, our management may be required to spend a significant amount of time and effort dealing with restructuring matters rather than focusing exclusively on our business operations. Bankruptcy Court protection and operating as debtors in possession also may make it more difficult to retain management and the key personnel necessary to the success of our business. In addition, during the pendency of the Chapter 11 Cases, our customers, vendors and service providers might lose confidence in our ability to reorganize our business successfully and may seek to establish alternative commercial relationships, renegotiate the terms of our agreements, terminate their relationships with us or require financial assurances from us, subject to the automatic stay imposed by the Bankruptcy Code.

Other significant risks include or relate to the following:

- the effects of the filing of the Chapter 11 Cases on our business and the interests of various constituents, including our shareholders;
- Bankruptcy Court rulings in the Chapter 11 Cases, including with respect to our motions, as well as the outcome of other pending litigation;
- our ability to operate within the restrictions and the liquidity limitations of the DIP Credit Agreement and any related orders entered by the Bankruptcy Court in connection with the Chapter 11 Cases;
- our ability to maintain strategic control as debtors in possession during the pendency of the Chapter 11 Cases;
- the length of time that we will operate with Chapter 11 protection and the continued availability of operating capital during the pendency of the Chapter 11 Cases;
- increased advisory costs during the pendency of the Chapter 11 Cases;
- the risks associated with restrictions on our ability to pursue some of our business strategies during the pendency of the Chapter 11 Cases;
- our ability to satisfy the conditions precedent to consummation of a plan of reorganization;
- the potential adverse effects of the Chapter 11 Cases on our business, cash flows, liquidity, financial condition and results of operations;
- the ultimate outcome of the Chapter 11 Cases in general;
- the cancellation of our existing equity securities, including our outstanding shares of common stock in the Chapter 11 Cases;
- the potential material adverse effects of claims that may not be discharged in the Chapter 11 Cases;
- uncertainties regarding the reactions of our customers, prospective customers, vendors and service providers to the Chapter 11 Cases;
- uncertainties regarding our ability to retain and motivate key personnel; and
- uncertainties and continuing risks associated with our ability to achieve our stated goals and continue as a going concern.

Further, under Chapter 11, transactions outside the ordinary course of business are subject to the prior approval of the Bankruptcy Court, which may limit our ability to respond in a timely manner to certain events, to take advantage of certain opportunities or adapt to changing market or industry conditions.

Because of the risks and uncertainties associated with the Chapter 11 Cases, we cannot predict or quantify the ultimate impact that events occurring during the Chapter 11 Cases may have on our business, cash flows, liquidity, financial condition and results of operations, nor can we provide any assurance as to our ability to continue as a going concern.

As a result of the Chapter 11 Cases, realization of assets and liquidation of liabilities are subject to uncertainty. While operating under the protection of the Bankruptcy Code, and subject to Bankruptcy Court approval or otherwise as permitted in the normal course of business, we may sell or otherwise dispose of assets and liquidate or settle liabilities for amounts other than those reflected in our consolidated financial statements.

Delays in the Chapter 11 Cases may increase the risk of us being unable to reorganize our business and emerge from bankruptcy and increase our costs associated with the bankruptcy process.

There can be no assurance that a plan of reorganization will become effective in accordance with its terms on the timeline we anticipate, or at all. Prolonged Chapter 11 proceedings could adversely affect our relationships with customers and employees, among other parties, which in turn could adversely affect our business, competitive position, financial condition, liquidity and results of operations and our ability to continue as a going concern. A weakening of our financial condition, liquidity and results of operations could adversely affect our ability to implement a plan of reorganization (or any other Chapter 11 plan). If we are unable to consummate a plan of reorganization, we may be forced to liquidate.

We are subject to certain risks and uncertainties if our exclusive right to file a plan of reorganization is terminated.

At the outset of a Chapter 11 case, the Bankruptcy Code provides debtors in possession the exclusive right to file and solicit acceptance of a plan of reorganization for the first 120 days of the bankruptcy case, subject to extension at the discretion of the court. All other parties are prohibited from filing or soliciting a plan of reorganization during this period. If the Bankruptcy Court terminates that right or the exclusivity period expires, there could be a material adverse effect on our ability to achieve confirmation of a plan in order to achieve our stated goals. The possible decision of creditors and/or other third parties, whose interest may be inconsistent with our own, to file alternative plans of reorganization could further protract the Chapter 11 Cases, leading us to continue to incur significant professional fees and costs. Because of these risks and uncertainties associated with the termination or expiration of our exclusivity rights, we cannot predict or quantify the ultimate impact that events occurring during the Chapter 11 Cases may have on our business, cash flows, liquidity, financial condition and results of operations, nor can we predict the ultimate impact that events occurring during the Chapter 11 Cases may have on our corporate or capital structure.

Adverse publicity in connection with the Chapter 11 Cases or otherwise could negatively affect our businesses.

Adverse publicity or news coverage relating to us, including, but not limited to, publicity or news coverage in connection with the Chapter 11 Cases, may negatively impact our efforts to establish and promote a positive image after emergence from the Chapter 11 Cases.

Trading in our common stock during the Chapter 11 Cases is highly speculative and poses substantial risks.

The RSA contemplates that our existing equity interests will be cancelled and discharged in connection with the Chapter 11 Cases and the holders of those equity interests will be entitled to no recovery. Accordingly, any trading in our common stock during the pendency of the Chapter 11 Cases is highly speculative and poses substantial risks to purchasers of our common stock.

Since November 30, 2020, our common stock has been trading on the OTC Pink Marketplace maintained by the OTC Markets Group, Inc. under the symbol "GPORQ". Securities traded in the over-the-counter market generally have significantly less liquidity than securities traded on a national securities exchange, due to factors such as a reduction in the number of investors that will consider investing in the securities, the number of market makers in the securities, reduction in securities analyst and news media coverage and lower market prices than might otherwise be obtained. In addition to those factors, the market for the outstanding shares of our common stock has been adversely affected by the provisions of the RSA that contemplate that our existing equity interests will be cancelled and discharged in connection with the Chapter 11 Cases and the holders of those equity interests, including the holders of our outstanding shares of common stock, will be entitled to no recovery relating to those equity interests. We can provide no assurance that our common stock will continue to trade on the OTC Pink Marketplace, whether broker-dealers will continue to provide public quotes of our common stock on that market, whether the trading volume of our common stock will be sufficient to provide for an efficient trading market or whether quotes for our common stock will continue to be provided on that market in the future.

The RSA is subject to significant conditions and milestones that may be difficult for us to satisfy.

There are certain material conditions we must satisfy under the RSA, including the timely satisfaction of milestones in the Chapter 11 Cases, which include the consummation of the financing contemplated by the Exit Credit Facilities and other transactions contemplated by a plan of reorganization. Our ability to timely complete such milestones is subject to risks and uncertainties, many of which are beyond our control.

A plan of reorganization may not become effective.

Even if a plan of reorganization is confirmed by the Bankruptcy Court, it may not become effective because it is subject to the satisfaction of certain conditions precedent (some of which are beyond our control). There can be no assurance that such conditions will be satisfied and, therefore, that a plan of reorganization will become effective and that the Debtors will emerge from the Chapter 11 Cases as contemplated by a plan of reorganization. If the effective date of a plan of reorganization is delayed, the Debtors may not have sufficient cash available to operate their businesses. In that case, the Debtors may need new or additional post-petition financing, which may increase the cost of consummating a plan of reorganization. There can be no assurance of the terms on which such financing may be available or if such financing will be available. If the transactions contemplated by a plan of reorganization are not completed, it may become necessary to amend the plan of reorganization. The terms of any such amendment are uncertain and could result in material additional expense and result in material delays to the Chapter 11 Cases.

The audited consolidated financial statements included in this Form 10-K for the period ended December 31, 2020 contain disclosures that express substantial doubt about our ability to continue as a going concern.

The audited consolidated financial statements included in this Form 10-K for the period ended December 31, 2020 have been prepared on a going concern basis, which contemplates the realization of assets and the satisfaction of liabilities and other commitments in the normal course of business and does not include any adjustments that might result from uncertainty about our ability to continue as a going concern. Such assumption may not be justified. Our liquidity has been negatively impacted by the prolonged depressed price averages we receive for the oil, natural gas and NGL we sell and our substantial indebtedness and associated debt-related expenses. As a result of these and other factors, we entered into the RSA and commenced the Chapter 11 Cases. The RSA contemplates that our equity investors, including the holders of our common stock, will lose the entire value of their investment in our business. The inclusion of disclosures that express substantial doubt about our ability to continue as a going concern may negatively impact the trading price of our common stock and have an adverse impact on our relationships with third parties with whom we do business, including our customers, subcontractors, suppliers and employees, and could have a material adverse impact on our business, financial condition, results of operations and cash flows.

Upon emergence from bankruptcy, the composition of our Board of Directors will likely change significantly.

The composition of our Board of Directors is expected to change significantly following the Chapter 11 Cases. Any new directors may have different backgrounds, experiences and perspectives from those individuals who currently serve on our Board of Directors and, thus, may have different views on the issues that will determine the future of our company. As a result, our future strategy and plans may differ materially from those of the past.

Financial, Liquidity and Commodity Price Risks

Natural gas, oil and NGL prices fluctuate widely, and lower prices for an extended period of time are likely to have a material adverse effect on our business.

Our revenues, cash flows, profitability, future rate of growth, production and the carrying value of our oil and natural gas properties depend significantly upon the prevailing prices for natural gas and, to a lesser extent, oil and NGL. We incur substantial expenditures to replace reserves, sustain production and fund our business plans. Low oil, natural gas and NGL prices can negatively affect the amount of cash available for capital expenditures, debt service and debt repayment and our ability to borrow money or raise additional capital and, as a result, could have a material adverse effect on our financial condition, results of operations, cash flows and reserves. In addition, periods of low natural gas, oil and NGL prices may result in ceiling test write-downs of our oil and natural gas properties.

Historically, the markets for natural gas, oil and NGL have been volatile, and they are likely to continue to be volatile. For example, during 2019, West Texas intermediate light sweet crude oil, which we refer to as West Texas Intermediate or WTI, prices ranged from $46.31 to $66.24 per barrel and the Henry Hub spot market price of natural gas ranged from $1.75 to $4.25 per MMBtu. During 2020, WTI prices ranged from $(36.98) to $63.27 per barrel and the Henry Hub spot market price of natural gas ranged from $1.33 to $3.14 per MMBtu.

Wide fluctuations in natural gas, oil and NGL prices may result from factors that are beyond our control, including:

- domestic and worldwide supplies of oil, natural gas and NGL, including U.S. inventories of oil and natural gas reserves;
- the level of prices, and expectations about future prices, of oil and natural gas;
- changes in the level of consumer and industrial demand, including impacts from global or national health epidemics and concerns, such as the recent coronavirus;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the expected rates of declining current production;
- changes in the level of consumer and industrial demand;
- the price and availability of alternative fuels;
- technological advances affecting energy consumption;
- risks associated with operating drilling rigs;
- the effectiveness of worldwide conservation measures;
- the availability, proximity and capacity of pipelines, other transportation facilities and processing facilities;
- the level and effect of trading in commodity futures markets, including by commodity price speculators and others;
- U.S. exports of oil, natural gas, liquefied natural gas and NGL;
- the price and level of foreign imports;
- the nature and extent of domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries and others to agree to and maintain oil price and production controls;
- political or economic instability or armed conflict in oil and natural gas producing regions, including the Middle East, Africa, South America and Russia;
- weather conditions;
- acts of terrorism; and
- domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future natural gas, oil and NGL price movements with any certainty. Even with natural gas, oil and NGL derivatives currently in place to mitigate price risks associated with a portion of our 2021 cash flows, we have substantial exposure to natural gas prices, and to a lesser extent, oil and NGL prices, in 2022 and beyond. In addition, a prolonged extension of lower prices could reduce the quantities of reserves that we may economically produce. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development activities are curtailed, full cost accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties.

Our commodity price risk management activities may limit the benefit we would receive from increases in commodity prices, may require us to provide collateral for derivative liabilities and involve risk that our counterparties may be unable to satisfy their obligations to us.

To manage our exposure to price volatility, we enter into natural gas, oil and NGL price derivative contracts. Our natural gas, oil and NGL derivative arrangements may limit the benefit we would receive from increases in commodity prices. The fair value of our natural gas, oil and NGL derivative instruments can fluctuate significantly between periods. Our decision to mitigate cash flow volatility through derivative arrangements, if any, is based in part on our view of current and future market conditions and our desire to stabilize cash flows necessary for the development of our proved reserves. We may choose not to enter into derivatives if the pricing environment for certain time periods is not deemed to be favorable. Additionally, we may choose to liquidate existing derivative positions prior to the expiration of their contractual maturities to monetize gain positions for the purpose of funding our capital program.

Natural gas, oil and NGL derivative transactions expose us to the risk that our counterparties, which are generally financial institutions, may be unable to satisfy their obligations to us. During periods of declining commodity prices, the value of our commodity derivative asset positions increase, which increases our counterparty exposure. Although the counterparties to our hedging arrangements are required to secure their obligations to us under certain scenarios, if any of our counterparties were to default on its obligations to us under the derivative contracts or seek bankruptcy protection, it could have an adverse effect on our ability to fund our planned activities and could result in a larger percentage of our future cash flows being exposed to commodity price changes.

We have a significant amount of indebtedness. Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects.

As of December 31, 2020, we had approximately $1.8 billion in principal amount of debt outstanding, primarily attributable to our senior notes. We also had $292.9 million in borrowings outstanding under our Pre-Petition Revolving Credit Facility and $157.5 million in borrowings under our DIP Credit Facility.

Our outstanding indebtedness could have important consequences to you, including the following:

- our high level of indebtedness could make it more difficult for us to satisfy our obligations with respect to our indebtedness, and any failure to comply with the obligations under any of our debt instruments, including their restrictive covenants, could result in a default under our revolving credit facility or the indentures governing our senior notes;
- the restrictions imposed on the operation of our business by the terms of our debt agreements may hinder our ability to take advantage of strategic opportunities to grow our business;
- our ability to obtain additional financing for working capital, capital expenditures, debt service requirements, restructuring, acquisitions or general corporate purposes may be impaired, which could be exacerbated by further volatility in the credit markets;
- our level of indebtedness could place us at a competitive disadvantage compared to our competitors that may have proportionately less debt;
- our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate may be limited;
- our high level of indebtedness makes us more vulnerable to economic downturns and adverse developments in our business; and
- we may be vulnerable to interest rate increases, as our borrowings under our revolving credit facility are at variable interest rates.

Any of the foregoing could have a material adverse effect on our business, financial condition, results of operations and prospects.

Our ability to pay our expenses and fund our working capital needs and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as commodity prices, other economic conditions and governmental regulation. If our borrowing base under our revolving credit facility decreases as a result of lower prices of natural gas, oil or NGL, operating difficulties, declines in reserves or for any other reason, our liquidity and ability to conduct additional exploration and development activities may be limited. To the extent that the value of the collateral pledged under our revolving credit facility declines as a result of lower oil and natural gas prices, asset dispositions or otherwise, we may be required to pledge additional collateral to maintain the current availability of the commitments thereunder, and we cannot assure you that we will be able to maintain a sufficiently high valuation to maintain the current borrowing base. In addition, if we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, or interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the instruments governing our indebtedness, we could be in default under the terms of the agreements governing such indebtedness. In the event of such default, the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest. More specifically, the lenders under our revolving credit facility could elect to terminate their commitments, cease making further loans and institute foreclosure proceedings against our assets, and we could be forced into bankruptcy or litigation. Any of the above risks could materially adversely affect our business, financial condition, cash flows and results of operations.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase.

Our earnings are exposed to interest rate risk associated with borrowings under our revolving credit facility and DIP credit facility. Our revolving credit facility and DIP Credit Facility are structured under floating rate terms. As such, our interest expense is sensitive to fluctuations in the London Interbank Offered Rate. At December 31, 2020, amounts borrowed under our revolving credit facility and DIP Credit Facility bore interest at the weighted average rates of 3.15% and 5.50%, respectively . A 1% increase in the average interest rate would have increased our interest expense by approximately $2.1 million based on outstanding borrowings under our revolving credit facility and DIP Credit Facility throughout the year ended December 31, 2020. An increase in our interest rate at the time we have variable interest rate borrowings outstanding under our revolving credit facility and DIP Credit Facility will increase our costs, which may have a material adverse effect on our results of operations and financial condition. As of December 31, 2020, we did not hedge our interest rate risk.

We have significant capital needs, and our ability to access the capital markets to raise capital on favorable terms is limited by our debt level and industry conditions.

Disruptions in the capital and credit markets, in particular with respect to the energy sector, could limit our ability to access these markets or may significantly increase our cost to borrow. Low commodity prices have caused and may continue to cause lenders to increase the interest rates under our revolving credit facility, enact tighter lending standards, refuse to refinance existing debt around maturity on favorable terms or at all and reduce or cease to provide funding to borrowers. If we are unable to access the capital and credit markets on favorable terms, it could have a material adverse effect on our business, financial condition, results of operations, cash flows and liquidity and our ability to repay or refinance our debt. Additionally, challenges in the economy have led and could further lead to reductions in the demand for natural gas, oil and NGL, or further reductions in the prices of natural gas, oil and NGL, which could have a negative impact on our financial position, results of operations and cash flows.

If we are unable to generate enough cash flow from operations to service our indebtedness or are unable to use future borrowings to refinance our indebtedness or fund other capital needs, in each case following our restructuring, we may have to undertake alternative financing plans, which may have onerous terms or may be unavailable.

Our earnings and cash flow could vary significantly from year to year due to the volatility of hydrocarbon commodity prices. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and commitments or to make necessary capital expenditures. A range of economic, competitive, business and industry factors will affect our future financial performance and, as a result, our ability to generate cash flow from operations and service our debt. Factors that may cause us to generate cash flow that is insufficient to meet our debt obligations include the events and risks related to our business, many of which are beyond our control. Any cash flow insufficiency would have a material adverse impact on our business, financial condition, results of operations, cash flows and liquidity and our ability to repay or refinance our debt.

If we do not generate sufficient cash flow from operations to service our indebtedness following our restructuring, or if future borrowings are not available to us in an amount sufficient to enable us to pay or refinance our indebtedness, we may be required to undertake various alternative financing plans, which may include:

- seeking alternative financing or additional capital investment;
- selling strategic assets;
- reducing or delaying capital investments; or
- revising or delaying our strategic plans.

We cannot assure you that we would be able to implement any alternative financing plans, if necessary, on commercially reasonable terms or at all,or that any such alternative financing plans would allow us to meet our debt obligations following our restructuring. If we are unable to generate sufficient cash flow to satisfy our debt obligations or to obtain necessary and sufficient alternative financing, our business, financial condition, results of operations, cash flows and liquidity could be materially and adversely affected.

Our development, acquisition and exploration operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. To increase reserves and production, we undertake development, exploration and other replacement activities or use third parties to accomplish these activities. We have made and expect to make in the future substantial capital expenditures in our business and operations for the development, production, exploration and acquisition of oil and natural gas reserves.

Historically, we have financed capital expenditures primarily with cash flow from operations, the issuance of equity and debt securities and borrowings under our revolving credit facility. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the volume of oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold;
- our ability to acquire, locate and produce economically new reserves; and
- our ability to borrow under our credit facility.

We cannot assure you that our operations and other capital resources will provide cash in sufficient amounts to maintain planned or future levels of capital expenditures. Further, our actual capital expenditures in 2021 could exceed our capital expenditure budget. In the event our capital expenditure requirements at any time are greater than the amount of capital we have available, we could be required to seek additional sources of capital, which may include traditional reserve base borrowings, debt financing, joint venture partnerships, production payment financings, sales of assets, offerings of debt or equity securities or other means. We cannot assure you that we will be able to obtain debt or equity financing on terms favorable to us, or at all.

If we are unable to fund our capital requirements, we may be required to curtail our operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves, or we may be otherwise unable to implement our development plan, complete acquisitions or take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations. In addition, a delay in or the failure to complete proposed or future infrastructure projects could delay or eliminate potential efficiencies.

Under our method of accounting for oil and natural gas properties, declines in commodity prices may result in impairment of asset value.

We use the full cost method of accounting for oil and natural gas operations.Accordingly, all costs, including nonproductive costs and certain general and administrative costs associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Net capitalized costs are limited to the estimated future net revenues, after income taxes, discounted at 10% per year, from proved oil and natural gas reserves and the cost of the properties not subject to amortization. Such capitalized costs, including the estimated future development costs and site remediation costs, if any, are depleted by an equivalent units-of-production method, converting natural gas to barrels at the ratio of six Mcf of natural gas to one barrel of oil.

Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter.The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the unweighted arithmetic average of the closing prices on the first day of each month for the 12-month period ending at the balance sheet date, adjusted for any contract provisions or financial derivatives, if any, that hedge oil and natural gas revenue, excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, less income tax effects related to differences between the book and tax basis of the oil and natural gas properties.If the net book value reduced by the related net deferred income tax liability exceeds the ceiling, an impairment or noncash writedown is required. A ceiling test impairment can result in a significant loss for a particular period. Once incurred, a write down of oil and natural gas properties is not reversible at a later date, even if oil or gas prices increase.As a result of the decline in commodity prices, we recorded a ceiling test impairment of $1.4 billion for the year ended December 31, 2020. If prices of natural gas, oil and natural gas liquids continue to decrease, we will be required to further write down the value of our oil and natural gas properties. Future non-cash asset impairments could negatively affect our results of operations.

A change of control could limit our use of net operating losses to reduce future taxable income.

As of December 31, 2020, we had a net operating loss, or NOL, carryforward of approximately $1.9 billion for federal income tax purposes. If we were to experience an "ownership change," as determined under Section 382 of the Internal Revenue Code of 1986, as amended (or the "Code"), our ability to offset taxable income arising after the ownership change with NOLs generated prior to the ownership change would be limited, possibly substantially. In general, an ownership change would establish an annual limitation on the amount of our pre-change NOLs we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate for the month in which such ownership change occurs. In general, an ownership change will occur if there is a cumulative increase in our ownership of more than 50 percentage points by one or more "5% shareholders" (as defined in the Code) at any time during a rolling three-year period. On April 30, 2020, the board of directors of the Company adopted a tax benefits preservation plan in order to protect against a possible limitation on the Company's ability to use its tax net operating losses and certain other tax benefits to reduce potential future U.S. federal income tax obligations. The Tax Benefits Preservation Plan is intended to prevent against such an ownership change by deterring any person or group from acquiring beneficial ownership of 4.9% or more of the Company's securities.

Industry, Business and Operational Risks

The oil and gas exploration and production industry is very competitive, and some of our competitors have greater financial and other resources than we do.

We face competition in every aspect of our business, including, but not limited to, buying and selling reserves and leases, obtaining goods and services needed to operate our business and marketing natural gas, oil or NGL. Competitors include multinational oil companies, independent production companies and individual producers and operators. Some of our competitors have greater financial and other resources than we do and, due to our debt levels and other factors, may have greater access to the capital and credit markets. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. As a result, these competitors may be able to address these competitive factors more effectively or weather industry downturns more easily than we can. We also face indirect competition from alternative energy sources, including wind, solar and electric power.

Our performance depends largely on the talents and efforts of highly skilled individuals and on our ability to attract new employees and to retain and motivate our existing employees. Competition in our industry for qualified employees is intense. If we are unsuccessful in attracting and retaining skilled employees and managerial talent, our ability to compete effectively may be diminished. We also compete for the equipment required to explore, develop and operate properties. Typically, during times of rising commodity prices, drilling and operating costs will also increase. During these periods, there is often a shortage of drilling rigs and other oilfield equipment and services, which could adversely affect our ability to execute our development plans on a timely basis and within budget.

If we are not able to replace reserves, we may not be able to sustain production.

Our future success depends largely upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves and production will decline over time. Thus, our future oil and natural gas reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves.

The actual quantities of and future net revenues from our proved reserves may be less than our estimates.

The estimates of our proved reserves and the estimated future net revenues from our proved reserves included in this report are based upon various assumptions, including assumptions required by the SEC relating to natural gas, oil and NGL prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating natural gas, oil and NGL reserves is complex and involves significant decisions and assumptions associated with geological, geophysical, engineering and economic data for each well. Therefore, these estimates are subject to future revisions.

Actual future production, natural gas, oil and NGL prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas, oil and NGL reserves most likely will vary from these estimates. Such variations may be significant and could materially affect the estimated quantities and present value of our proved reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development drilling, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

As of December 31, 2020, approximately 41% of our total estimated proved reserves were PUDs and may not be ultimately developed or produced. Recovery of PUDs requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve reports of our independent petroleum engineers assume that substantial capital expenditures are required to develop such reserves. You should be aware that the estimated development costs may not equal our actual costs, development may not occur as scheduled and results may not be as estimated. Delays in the development of our reserves, further decreases in commodity prices or increases in costs to drill and develop such reserves will reduce the future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomical. If we choose not to develop our PUDs, or if we are not otherwise able to successfully develop them, we will be required to remove them from our reported proved reserves. In addition, under the SEC's reserve reporting rules, because PUDs generally may be booked only if they relate to wells scheduled to be drilled within five years of the date of booking, we may be required to remove any PUDs that are not developed within this five-year time frame.

You should not assume that the present values included in this report represent the current market value of our estimated reserves. In accordance with SEC requirements, the estimates of our present values are based on prices and costs as of the date of the estimates. The price on the date of estimate is calculated as the average natural gas and oil price during the 12 months ending in the current reporting period, determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period. The December 31, 2020 present value is based on a $1.99 per MMBtu of gas price and a $39.54 per Bbl of oil price, before considering basis differential adjustments. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of an estimate.

Actual future net revenues from our oil and natural gas properties will also be affected by factors such as:

- actual prices we receive for oil and natural gas;
- the amount and timing of actual production;
- supply of and demand for oil and natural gas; and
- changes in governmental regulations or taxation.

The timing of both the production and the expenses from the development and production of oil and natural gas properties will affect both the timing of future net cash flows from our proved reserves and their present value. Any changes in demand for oil and natural gas, governmental regulations or taxation will also affect the future net cash flows from our production. In addition, the 10% discount factor that is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes is not necessarily the most appropriate discount factor. Interest rates in effect from time to time and the risks associated with our business or the oil and gas industry in general will affect the appropriateness of the 10% discount factor.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

We have a substantial inventory of undeveloped properties. Development and exploratory drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not necessarily reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

We acquire significant amounts of unproven properties that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our initial investments. Additionally, there can be no assurance that undeveloped properties acquired by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive, or that we will recover all or any portion of our investment in such undeveloped properties or wells.

Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient commercial quantities to cover the drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling and completion operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, title problems, equipment failures or accidents, shortages of midstream transportation, equipment or personnel, environmental issues, state or local bans or moratoriums on hydraulic fracturing and produced water disposal, and a decline in commodity prices, among others. The profitability of wells, particularly in certain of the areas in which we operate, will be reduced or eliminated if commodity prices decline. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and future market prices for natural gas, oil and NGL, costs associated with producing natural gas, oil and NGL and our ability to add reserves at an acceptable cost. Drilling results in our newer oil and liquids-rich shale plays may be more uncertain than in shale plays that are more developed and have longer established production histories, and we can provide no assurance that drilling and completion techniques that have proven to be successful in other shale formations to maximize recoveries will be ultimately successful when used in newly developed shale formations. All costs of development and exploratory drilling activities are capitalized under the full cost method, even if the activities do not result in commercially productive discoveries, which may result in a future impairment of our oil and natural gas properties if commodity prices decrease.

We rely to a significant extent on seismic data and other technologies in evaluating undeveloped properties and in conducting our exploration activities. The seismic data and other technologies we use do not allow us to know conclusively, prior to acquisition of undeveloped properties, or drilling a well, whether oil or natural gas is present or may be produced economically. If we incur significant expense in acquiring or developing properties that do not produce as expected or at profitable levels, it could have a material adverse effect on our results of operations and financial condition.

Part of our strategy involves drilling in existing or emerging shale plays using the latest available horizontal drilling and completion techniques; therefore, the results of our planned exploratory drilling in these plays are subject to risks associated with drilling and completion techniques and drilling results may not meet our expectations for reserves or production.

Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage. In addition, to the extent we engage in horizontal drilling, those activities may adversely affect our ability to successfully drill in one or more of our identified vertical drilling locations. Furthermore, certain of the development activities we employ, such as offset drilling and multi-well pad drilling, may cause irregularities or interruptions in production due to, in the case of offset drilling, adjacent wells being shut in and, in the case of multi-well pad drilling, the time required to drill and complete multiple wells before any such wells begin producing.

The results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas often have limited or no production history and consequently we are less able to predict future drilling results in these areas, such as our SCOOP play in Oklahoma. The area was historically developed by vertical wells drilled through multiple stacked reservoirs and recent development has focused on the Woodford formation; however, development in the Sycamore and Springer formations has been limited. As emerging formations, our drilling results in this area are more uncertain than drilling results in areas that are more developed and have been producing for a longer period of time. Since limited production history from horizontal wells in the SCOOP Sycamore and Springer formations exists over our acreage position, it is difficult to predict our future drilling results.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems, or declines in natural gas and oil prices, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline in the future.

Our undeveloped acreage must be drilled before lease expiration to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established. In addition, many of our oil and natural gas leases require us to drill wells that are commercially productive, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. Although 74% of our Utica acreage is held by existing production, the remaining acreage is subject to expiration. Of the remaining 26% of our Utica acreage not held by production, 24% will be subject to expiration in 2021, 29% in 2022, 30% in 2023 and 17% thereafter, although our Utica leases generally grant us the right to extend these leases for an additional five-year period. Although 99% of our SCOOP acreage is held by existing production, the remaining acreage is subject to expiration. Of the remaining 1% of our SCOOP acreage not held by production, 78% will be subject to expiration in 2021, 12% in 2022, 5% in 2023 and 5% thereafter. Although we seek to actively manage our undeveloped properties, our drilling plans for these areas are subject to change based upon various factors, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. Low commodity prices may cause us to delay our drilling plans and, as a result, lose our right to develop the related properties. The cost to renew expiring leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. If we are unable to fund renewals of expiring leases, we could lose portions of our acreage and our actual drilling activities may differ materially from our current expectations, which could adversely affect our business.

Oil and natural gas operations are uncertain and involve substantial costs and risks. Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits.

Our oil and natural gas operating activities are subject to numerous costs and risks, including the risk that we will not encounter commercially productive oil or gas reservoirs. Drilling for oil, natural gas and NGL can be unprofitable, not only from dry holes, but from productive wells that do not return a profit because of insufficient revenue from production or high costs. Substantial costs are required to locate, acquire and develop oil and gas properties, and we are often uncertain as to the amount and timing of those costs. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Declines in commodity prices and overruns in budgeted expenditures are common risks that can make a particular project uneconomic or less economic than forecasted. While both exploratory and developmental drilling activities involve these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. For the 11% of our daily production volumes from properties which we did not serve as operator as of December 31, 2020, we are dependent on the operator for operational and regulatory compliance. In addition, our oil and gas properties can become damaged, our operations may be curtailed, delayed or canceled and the costs of such operations may increase as a result of a variety of factors, including, but not limited to:

- unexpected drilling conditions, pressure conditions or irregularities in reservoir formations;
- loss of drilling fluid circulation;
- equipment failures or accidents;
- fires, explosions, blowouts, cratering or loss of well control, as well as the mishandling or underground migration of fluids and chemicals;
- risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground migration of fracturing fluids, including chemical additives;
- adverse weather conditions and natural disasters, such as tornadoes, earthquakes, hurricanes and extreme temperatures;
- issues with title or in receiving governmental permits or approvals;
- restricted takeaway capacity for our production, including due to inadequate midstream infrastructure or constrained

downstream markets;

- environmental hazards or liabilities, including liabilities for environmental damage caused by previous owners of properties purchased by us;
- restrictions in access to, or disposal of, water used or produced in drilling and completion operations;
- shortages or delays in the availability of services or delivery of equipment; and
- unexpected or unforeseen changes in regulatory policy, and political or public opinions.

The occurrence of one or more of these factors could result in a partial or total loss of our investment in a particular property, as well as significant liabilities.

While we may maintain insurance against some, but not all, of the risks described above, our insurance may not be adequate to cover casualty losses or liabilities, and our insurance does not cover penalties or fines that may be assessed by a governmental authority. For certain risks, such as political risk, business interruption, war, terrorism and piracy, we have limited or no insurance coverage. Also, in the future we may not be able to obtain insurance at premium levels that justify its purchase. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations or cash flow. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

We are not the operator of all of our oil and natural gas properties and therefore are not in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves on such properties.

We are not the operator of all of the properties in which we have an interest, and have limited ability to exercise influence over the operations of such non-operated properties or their associated costs. Dependence on the operator and other working interest owners for these projects, and limited ability to influence operations and associated costs, could prevent the realization of targeted returns on capital in drilling or acquisition activities. The success and timing of development and exploration activities on properties operated by others will depend upon a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the availability of suitable drilling equipment, production and transportation infrastructure and qualified operating personnel;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of the reserves.

In addition, when we are not the majority owner or operator of a particular oil or natural gas project, if we are not willing or able to fund our capital expenditures relating to such projects when required by the majority owner or operator, our interests in these projects may be reduced or forfeited.

Oil and natural gas production operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water. Our ability to produce natural gas, oil and NGL economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our operations or are unable to dispose of or recycle the water we use economically and in an environmentally safe manner.

Water is an essential component of oil and natural gas production during the drilling, and in particular, hydraulic fracturing, process. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our operations. For water sourcing, we first seek to use non-potable water supplies for our operational needs. In certain areas, there may be insufficient local aquifer capacity to provide a source of water for drilling activities. Water must then be obtained from other sources and transported to the drilling site. An inability to secure sufficient amounts of water or to dispose of or recycle the water used in our operations could adversely impact our operations in certain areas. The imposition of new environmental regulations could further restrict our ability to conduct operations such as hydraulic fracturing by restricting the disposal of things such as produced water and drilling fluids.

Substantially all of our producing properties are located in Eastern Ohio and Oklahoma, making us vulnerable to risks associated with operating in these regions.

Our largest fields by production are located in Eastern Ohio and Oklahoma. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production in these geographic regions caused by weather conditions such as snow, ice, fog, rain, hurricanes, tornados or other natural disasters or lack of field infrastructure. Losses could occur for uninsured risks or in amounts in excess of any existing insurance coverage. We may not be able to obtain and maintain adequate insurance at rates we consider reasonable and it is possible that certain types of coverage may not be available.

The loss of one or more of the purchasers of our production could adversely affect our business, results of operations, financial condition and cash flows.

The largest purchaser of our oil and natural gas during the year ended December 31, 2020 accounted for approximately 12% of our total natural gas, oil and NGL revenues. If this purchaser or one or more other significant purchasers, are unable to satisfy its contractual obligations, we may be unable to sell such production to other customers on terms we consider acceptable. Further, the inability of one or more of our customers to pay amounts owed to us could adversely affect our business, financial condition, results of operations and cash flows.

The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies, oilfield services or personnel may restrict our operations.

The oil and natural gas industry is cyclical, which can result in shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies and personnel. When shortages occur, the costs and delivery times of rigs, equipment and supplies increase and demand for and wage rates of qualified drilling rig crews also rise with increases in demand. In accordance with customary industry practice, we rely on independent third party service providers to provide most of the services necessary to drill new wells. If we are unable to secure a sufficient number of drilling rigs at reasonable costs, our financial condition and results of operations could suffer, and we may not be able to drill all of our acreage before our leases expire. Shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies, personnel, trucking services, tubulars, fracking and completion services and production equipment could delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations.

Our operations may be adversely affected by pipeline, trucking and gathering system capacity constraints and may be subject to interruptions that could adversely affect our cash flow.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of natural gas lines and transportation barges owned by third parties. In general, we do not control these transportation facilities and our access to them may be limited or denied. In certain resource plays, the capacity of gathering and transportation systems is insufficient to accommodate potential production from existing and new wells. A significant disruption in the availability of these transportation facilities or our compression and other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas and thereby cause a significant interruption in our operations.

With respect to our Utica acreage where we are focusing a portion of our exploration and development activity, historically there has been no or only limited infrastructure in this area and the commencement of production from our initial and subsequent wells on our Utica acreage has been delayed due to challenges in obtaining rights-of-way and acquiring necessary state and federal permitting and the completion of facilities by our midstream service provider. Capital constraints could limit the construction of new pipelines and gathering systems and the providing or expansion of trucking services by third parties in the Utica and the other areas in which we operate. Until this new capacity is available, we may experience delays in producing and selling our natural gas, oil and NGL. In such event, we might have to shut in our wells awaiting a pipeline connection or capacity or sell natural gas, oil or NGL production at significantly lower prices than those quoted on NYMEX or than we currently project, which would adversely affect our results of operations.

A portion of our natural gas, oil and NGL production in any region may be interrupted, or shut in, from time to time for numerous reasons, including weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could materially adversely affect our cash flow.

Our forecasted production is less than our firm transportation commitment levels under our firm transportation contracts due to decreased developmental activities, which will result in excess firm transportation costs and may have a material adverse effect on our operations.

As of December 31, 2020, we had entered into firm transportation contracts to deliver approximately 1,399,000 and 1,467,000 MMBtu per day for 2021 and 2022, respectively. Under these firm transportation contracts, we are obligated to deliver minimum daily volumes or pay fees for any deficiencies in deliveries. As a result of the reduced production from our Utica or SCOOP acreage due to decreased developmental activities, taking into consideration the current low commodity price environment, we expect that we will be unable to meet our obligations under the existing firm transportation contracts, resulting in fees, which may be significant and may have a material adverse effect on our operations.

The outbreak of the novel coronavirus, or COVID-19, has affected and may materially adversely affect, and any future outbreak of any other highly infectious or contagious diseases may materially adversely affect, our operations, financial performance and condition, operating results and cash flows.

The recent outbreak of COVID-19 has affected, and may materially adversely affect, our business and financial and operating results. The severity, magnitude and duration of the current COVID-19 outbreak is uncertain, rapidly changing and hard to predict. In 2020, the outbreak has significantly impacted economic activity and markets around the world, and COVID-19 or another similar outbreak could negatively impact our business in numerous ways, including, but not limited to, the following:

- our revenue may be reduced if the outbreak results in an economic downturn or recession, as many experts predict, to the extent it leads to a prolonged decrease in the demand for natural gas and, to a lesser extent, NGL and oil;
- our operations may be disrupted or impaired, thus lowering our production level, if a significant portion of our employees or contractors are unable to work due to illness or if our field operations are suspended or temporarily shut-down or restricted due to control measures designed to contain the outbreak;
- the operations of our midstream service providers, on whom we rely for the transmission, gathering and processing of a significant portion of our produced natural gas, oil and NGL, may be disrupted or suspended in response to containing the outbreak, and/or the difficult economic environment may lead to the bankruptcy or closing of the facilities and infrastructure of our midstream service providers, which may result in substantial discounts in the prices we receive for our produced natural gas, oil and NGL or result in the shut-in of producing wells or the delay or discontinuance of development plans for our properties; and
- the disruption and instability in the financial markets and the uncertainty in the general business environment may affect our ability to execute on our business strategy, including our focus on reducing our leverage profile. If we are not able to successfully execute our plan to reduce our leverage profile, our high level of indebtedness could make it more difficult for us to satisfy our obligations with respect to our indebtedness, and any failure to comply with the obligations under any of our debt instruments, including their restrictive covenants, could result in a default under our revolving credit facility or the indentures governing our senior notes. Additionally, our credit ratings may be lowered, we may reduce or delay our planned capital expenditures or investments, and we may revise or delay our strategic plans.

We expect that the principal areas of operational risk for us are availability of service providers and supply chain disruption. Active development operations, including drilling and fracking operations, represent the greatest risk for transmission given the number of personnel and contractors on site. While we believe that we are following best practices under COVID-19 guidance, the potential for transmission still exists. In certain instances, it may be necessary or determined advisable for us to delay development operations.

In addition, the COVID-19 pandemic has increased volatility and caused negative pressure in the capital and credit markets. As a result, we may experience difficulty accessing the capital or financing needed to fund our exploration and production operations, which have substantial capital requirements, or refinance our upcoming maturities on satisfactory terms or at all. We typically fund our capital expenditures with existing cash and cash generated by operations (which is subject to a number of variables, including many beyond our control) and, to the extent our capital expenditures exceed our cash resources, from borrowings under our revolving credit facility and other external sources of capital. If our cash flows from operations or the borrowing capacity under our revolving credit facility are insufficient to fund our capital expenditures and we are unable to obtain the capital necessary for our planned capital budget or our operations, we could be required to curtail our operations and the development of our properties, which in turn could lead to a decline in our reserves and production, and could adversely affect our business, results of operations and financial position.

To the extent the COVID-19 pandemic adversely affects our business and financial results, it may also have the effect of heightening many of the other risks set forth in Item 1A., "Risk Factors" in our Annual Report on Form 10-K, such as those relating to our financial performance and debt obligations. The rapid development and fluidity of this situation precludes any prediction as to the ultimate adverse impact of COVID-19 on our business, which will depend on numerous evolving factors and future developments that we are not able to predict, including the length of time that the pandemic continues, its effect on the demand for natural gas, NGL and oil, the response of the overall economy and the financial markets as well as the effect of governmental actions taken in response to the pandemic.

A deterioration in general economic, business or industry conditions would have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit and the European, Asian and the United States financial markets have contributed to economic volatility and diminished expectations for the global economy. Historically, concerns about global economic growth have had a significant impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and materially adversely impact our results of operations, liquidity and financial condition.

Terrorist activities could materially and adversely affect our business and results of operations.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign attacks, as well as military or other actions taken in response to these acts, could cause instability in the global financial and energy markets. Continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy in unpredictable ways, including the disruption of energy supplies and markets, increased volatility in commodity prices, or the possibility that the infrastructure on which we rely could be a direct target or an indirect casualty of an act of terrorism, and, in turn, could materially and adversely affect our business and results of operations. These factors, combined with volatility in commodity prices, business and consumer confidence and unemployment rates, have in the past precipitated, and may in the future precipitate, an economic slowdown.

Cyber-attacks targeting systems and infrastructure used by the oil and gas industry and related regulations may adversely impact our operations and, if we are unable to obtain and maintain adequate protection for our data, our business may be harmed.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. We depend on digital technology to estimate quantities of oil, natural gas and NGL reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our customers, employees and third-party partners. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Our technologies, systems, networks, and those of our vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized access to our seismic data, reserves information, customer or employee data or other proprietary or commercially sensitive information could lead to data corruption, communication interruption, or other disruptions in our exploration or production operations or planned business transactions, any of which could have a material adverse impact on our results of operations. If our information technology systems cease to function properly or our cybersecurity is breached, we could suffer disruptions to our normal operations, which may include drilling, completion, production and corporate functions. A cyber-attack involving our information systems and related infrastructure, or that of our business associates, could result in supply chain disruptions that delay or prevent the transportation and marketing of our production, non-compliance leading to regulatory fines or penalties, loss or disclosure of, or damage to, our or any of our customer's, supplier's or royalty owners' data or confidential information that could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps.

In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Our systems and insurance coverage for protecting against cyber security risks may not be sufficient. As cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerabilities to cyber-attacks. In addition, new laws and regulations governing data privacy and the unauthorized disclosure of confidential information pose increasingly complex compliance challenges and potentially elevate costs, and any failure to comply with these laws and regulations could result in significant penalties and legal liability.

Legal and Regulatory Risks

The ultimate outcome of pending legal and governmental proceedings is uncertain, and there are significant costs associated with these matters.

We are defending against claims by royalty owners alleging, among other things, that we underpaid royalty owners. The resolution of disputes regarding past payments could cause our future obligations to royalty owners to increase and would negatively impact our future results of operations.

The outcome of any pending or future litigation or governmental regulatory matter is uncertain and may adversely affect our results of operations. In addition, we have incurred substantial legal expenses in the past three years, and such expenses may continue to be significant in the future. Further, attention to these matters by members of our senior management has been required, reducing the time they have available to devote to managing our business.

Decisions by the Ohio Supreme Court interpreting the Ohio Dormant Mineral Act relating to preservation of mineral rights by surface owners could require certain curative efforts to vest title in a portion of our leasehold acreage, increase our leasehold expenses, subject us to payment of additional royalties or result in the loss of some of our leasehold acreage in Ohio.

On September 15, 2016, the Ohio Supreme Court issued a series of decisions relating to the Ohio Dormant Mineral Act, which we refer to as the ODMA. In the lead case, Corban v. Chesapeake Exploration L.L.C., the court concluded that the 1989 version of the ODMA did not transfer ownership of dormant mineral rights automatically, by operation of law. Instead, prior to 2006, surface owners were required to bring a quiet title action to establish abandonment of mineral rights. After June 30, 2006, (the effective date of the 2006 version of the ODMA), surface owners are required to follow the statutory notice and recording procedures enacted in 2006. We have assessed the impact of these recent Ohio Supreme Court decisions on our operations in Ohio where the majority of our acreage and our producing properties are located and have taken steps to mitigate any potential risks identified as a result of our assessment. However, the Ohio Supreme Court decisions could require certain curative efforts to vest title in a portion of our leasehold acreage, increase our leasehold expense, subject us to payment of additional royalties or result in the loss of some of our leasehold acreage in Ohio, any of which could have an adverse effect on our results of operations and financial condition.

We are subject to extensive governmental regulation and ongoing regulatory changes, which could adversely impact our business.

Our operations are subject to extensive federal, state, tribal, local and other laws, rules and regulations, including with respect to environmental matters, worker health and safety, wildlife conservation, the gathering and transportation of oil, gas and NGL, conservation policies, reporting obligations, royalty payments, unclaimed property and the imposition of taxes. Such regulations include requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling, completion and well operations. If permits are not issued, or if unfavorable restrictions or conditions are imposed on our drilling or completion activities, we may not be able to conduct our operations as planned. For example, on January 20, 2021, the Acting Secretary for the Department of the Interior signed an order effectively suspending new fossil fuel leasing and permitting on federal lands for 60 days. Then on January 27, 2021, President Biden issued an executive order indefinitely suspending new oil and natural gas leases on public lands or in offshore waters pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices. To the extent that the review results in the development of additional restrictions on drilling, limitations on the availability of leases, or restrictions on the ability to obtain required permits, it could have a material adverse impact on our operations. In addition, we may be required to make large, sometimes unexpected, expenditures to comply with applicable governmental laws, rules, regulations, permits or orders.

In addition, changes in public policy have affected, and in the future could further affect, our operations. Regulatory changes could, among other things, restrict production levels, impose price controls, alter environmental protection requirements and increase taxes, royalties and other amounts payable to the government. Our operating and compliance costs could increase further if existing laws and regulations are revised or reinterpreted or if new laws and regulations become applicable to our operations. We do not expect that any of these laws and regulations will affect our operations materially differently than they would affect other companies with similar operations, size and financial strength. Although we are unable to predict changes to existing laws and regulations, such changes could significantly impact our profitability, financial condition and liquidity. As is discussed below this is particularly true of changes related to pipeline safety, seismic activity, hydraulic fracturing, climate change and endangered species designations.

Pipeline Safety. The pipeline assets owned by our midstream service providers are subject to stringent and complex regulations related to pipeline safety and integrity management. The Pipeline and Hazardous Materials Safety Administration (PHMSA) has established a series of rules that require pipeline operators to develop and implement integrity management programs for gas, NGL and condensate transmission pipelines as well as certain low stress pipelines and gathering lines transporting hazardous liquids, such as oil, that, in the event of a failure, could affect “high consequence areas.” Recent PHMSA rules have also extended certain requirements for integrity assessments and leak detections beyond high consequence areas. Further, legislation funding PHMSA through 2023 requires the agency to engage in additional rulemaking to amend the integrity management program, emergency response plan, operation and maintenance manual, and pressure control recordkeeping requirements for gas distribution operators; to create new leak detection and repair program obligations; and to set new minimum federal safety standards for onshore gas gathering lines. At this time, we cannot predict the cost of these requirements or other potential new or amended regulations, but they could be significant, and any such costs incurred by our midstream service providers could result in increased midstream gathering and processing expenses for us. Moreover, violations of pipeline safety regulations by our midstream service providers could result in the imposition of significant penalties which may impact the cost or availability of pipeline capacity necessary for our operations.

Seismic Activity. Earthquakes in some of our operating areas and elsewhere have prompted concerns about seismic activity and possible relationships with the energy industry. For example, the OCC issued guidance to operators in the SCOOP and STACK areas for management of certain seismic activity that may be related to hydraulic fracturing or water disposal activities. Legislative and regulatory initiatives intended to address these concerns may result in additional levels of regulation or other requirements that could lead to operational delays, increase our operating and compliance costs or otherwise adversely affect our operations. In addition, we could be subject to third-party lawsuits seeking damages or other remedies as a result of alleged induced seismic activity in our areas of operation.

Hydraulic Fracturing. Several states have adopted or are considering adopting regulations that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing operations. Three states (New York, Maryland and Vermont) have banned the use of high-volume hydraulic fracturing. In addition to state laws, some local municipalities have adopted or are considering adopting land use restrictions, such as city ordinances, that may restrict or prohibit the performance of well drilling in general or hydraulic fracturing in particular. There have also been certain governmental reviews that focus on deep shale and other formation completion and production practices, including hydraulic fracturing. Governments may continue to study hydraulic fracturing. We cannot predict the outcome of future studies, but based on the results of these studies to date, federal and state legislatures and agencies may seek to further regulate or even ban hydraulic fracturing activities. In addition, if existing laws and regulations with regard to hydraulic fracturing are revised or reinterpreted or if new laws and regulations become applicable to our operations through judicial or administrative actions, our business, financial condition, results of operations and cash flows could be adversely affected. A decision is pending.

We cannot predict whether additional federal, state or local laws or regulations applicable to hydraulic fracturing will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. If additional levels of regulation or permitting requirements were imposed on hydraulic fracturing operations, our business and operations could be subject to delays, increased operating and compliance costs and potential bans. Additional regulation could also lead to greater opposition to hydraulic fracturing, including litigation.

Climate Change. Continuing political and social attention to the issue of climate change has resulted in legislative, regulatory and other initiatives to reduce greenhouse gas emissions, such as carbon dioxide and methane. Policy makers at both the U.S. federal and state levels have introduced legislation and proposed new regulations designed to quantify and limit the emission of greenhouse gases through inventories, limitations or taxes on greenhouse gas emissions. Several states where we operate have imposed venting and flaring limitations designed to reduce methane emissions from oil and gas exploration and production activities. Legislative and state initiatives to date have generally focused on the development of cap and trade or carbon tax programs. Renewable energy standards (also referred to as renewable portfolio standards) require electric utilities to provide a specified minimum percentage of electricity from eligible renewable resources, with potential increases to the required percentage over time. The development of a federal renewable energy standard, or the development of additional or more stringent renewable energy standards at the state level could reduce the demand for oil and gas, thereby adversely impacting our earnings, cash flows and financial position. Cap and trade programs offer greenhouse gas emission allowances that are gradually reduced over time. A cap and trade program or expanded use of cap and trade programs at the state level could impose direct costs on us through the purchase of allowances and could impose indirect costs by incentivizing consumers to shift away from fossil fuels. In addition, federal or state carbon taxes could directly increase our costs of operation and similarly incentivize consumers to shift away from fossil fuels.

In addition, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities. Members of the investment community have also begun to screen companies such as ours for sustainability performance, including practices related to greenhouse gases and climate change, before investing in our common units. Any efforts to improve our sustainability practices in response to these pressures may increase our costs, and we may be forced to implement technologies that are not economically viable in order to improve our sustainability performance and to meet the specific requirements to perform services for certain customers.

These various legislative, regulatory and other activities addressing greenhouse gas emissions could adversely affect our business, including by imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations, which could require us to incur costs to reduce emissions of greenhouse gases associated with our operations. Limitations on greenhouse gas emissions could also adversely affect demand for oil and gas, which could lower the value of our reserves and have a material adverse effect on our profitability, financial condition and liquidity. Furthermore, increasing attention to climate change risks has resulted in increased likelihood of governmental investigations and private litigation, which could increase our costs or otherwise adversely affect our business.

Endangered Species. The Endangered Species Act (ESA) prohibits the taking of endangered or threatened species or their habitats. While some of our assets and lease acreage may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in material compliance with the ESA. However, the designation of previously unidentified endangered or threatened species in areas where we intend to conduct construction activity or the imposition of seasonal restrictions on our construction or operational activities could materially limit or delay our plans.

Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could have a material adverse effect on our business.

State and federal regulatory agencies have recently focused on a possible connection between hydraulic fracturing related activities, particularly the underground injection of wastewater into disposal wells, and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In addition, a number of lawsuits have been filed in some states, including in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise to assess the relationship between seismicity and the use of such wells.

In our Utica and SCOOP operations, we make an effort to reuse/recycle all produced water from production and completion activities through our fracture stimulation operations when active. While our objective is to recycle or share 100% of all produced water, we do inject water into third-party commercially operated disposal wells in line with all state and federal mandated practices and cease produced water recycle whenever fracture stimulation operations are idle once sharing opportunities with other operators have been exhausted. In the state of Ohio, all water used during drilling operations is disposed of through injection into third-party salt water disposal wells regulated by applicable state agencies.

Future U.S. and state tax legislation may adversely affect our business, results of operations, financial condition and cash flow.

From time to time, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws affecting the oil and gas industry. For example, legislative proposals have been introduced in the U.S. Congress in the past that, if enacted, would (i) eliminate the immediate deduction for intangible drilling and development costs, (ii) repeal the percentage depletion allowance for oil and natural gas properties, and (iii) extend the amortization period for certain geological and geophysical expenditures. No accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. In addition, at the state level, legislative changes imposing increased taxes on oil and gas production have periodically been considered in Ohio and Oklahoma. These proposed changes in the U.S. federal and state tax law, if adopted, or other similar changes that would impose additional tax on our activities or reduce or eliminate deductions currently available with respect to natural gas and oil exploration, development or similar activities, could adversely affect our business, results of operations, financial condition and cash flows.

Our business is subject to complex and evolving laws and regulations regarding privacy and data protection.

The regulatory environment surrounding data privacy and protection is constantly evolving and can be subject to significant change. New laws and regulations governing data privacy and the unauthorized disclosure of confidential information pose increasingly complex compliance challenges and potentially elevate our costs as we collect and store personal data related to royalty owners. Any failure to comply with these laws and regulations could result in significant penalties and legal liability. For example, the California Consumer Privacy Act ("CCPA") was signed into law on June 28, 2018 and largely took effect on January 1, 2020. The CCPA, among other things, contains new disclosure obligations for businesses that collect personal information about California residents and enhanced consumer protections for those individuals, and provides for statutory fines for data security breaches or other CCPA violations. Meanwhile, over fifteen other states have considered privacy laws like the CCPA. We will continue to monitor and assess the impact of these state laws, which may impose substantial penalties for violations, impose significant costs for investigations and compliance, require us to change our business practices, allow private class-action litigation and carry significant potential liability for our business should we fail to comply with any such applicable laws.

Any failure, or perceived failure, by us to comply with applicable data protection laws could result in heightened risk of litigation, including private rights of action, and proceedings or actions against us by governmental entities or others, subject us to significant fines, penalties, judgments and negative publicity, require us to change our business practices, increase the costs and complexity of compliance, and adversely affect our business. As noted above, we are also subject to the possibility of cyber incidents or attacks, which themselves may result in a violation of these laws. Additionally, if we acquire a company that has violated or is not in compliance with applicable data protection laws, we may incur significant liabilities and penalties as a result.

We may have material liability related to plugging and abandonment, reclamation, civil lawsuits and regulatory fines associated with our divested Louisiana assets.

Gulfport operated hundreds of wells in Louisiana before divesting substantially all Louisiana assets to PEL Gulf Coast, LLC ("Perdido") in 2019. The Perdido Purchase Sale Agreement ("PSA") contains a broad assumption of all obligations, as well as defense and indemnity obligations, in favor of Gulfport and against Perdido for all current and former Gulfport wells. To the extent Perdido files for bankruptcy protection or is unable to meet its obligations, Gulfport may have material liability related to plugging and abandonment, reclamation, civil lawsuits and regulatory fines.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Information regarding our properties is included in Item 1 and in the Supplemental Information on Oil and Gas Exploration and Production Activities in Note 19 of the notes to our consolidated financial statements included in this report.

ITEM 3. LEGAL PROCEEDINGS

The information with respect to this Item 3. Legal Proceedings is set forth in Note 18 in the accompanying consolidated financial statements. Additionally, see Note 1 and Note 2 in the accompanying consolidated financial statements for additional discussion of on-going claims and disputes in our Chapter 11 proceedings, certain of which may be material.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Common Stock

On November 27, 2020, our common stock was suspended from trading on NASDAQ. On November 30, 2020, our common stock began trading on the OTC Pink Marketplace maintained by the OTC Markets Group, Inc. under the symbol "GPORQ". On February 2, 2021, NASDAQ filed a Form 25 delisting our common stock from trading on NASDAQ, which delisting became effective 10 days after the filing of the Form 25. In accordance with Rule 12d2-2 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), the de-registration of our common stock under section 12(b) of the Exchange Act became effective on February 12, 2021.

Shareholders

At the close of business on February 22, 2021, there were approximately 311 stockholders and 19,574 beneficial owners of our common stock.

Dividends

We have never paid dividends on our common stock.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected consolidated financial data of Gulfport as of and for the years ended December 31, 2020, 2019, 2018, 2017 and 2016. The data are derived from our audited consolidated financial statements. The table below should be read in connection with *Management's Discussion and Analysis of Financial Condition and Results of Operations* and our consolidated financial statements and the related notes appearing elsewhere in Items 7 and 8, respectively, of this report.

	Fiscal Year Ended December 31,				
	2020	2019	2018	2017	2016
	(In thousands, except share data)				
Selected Consolidated Statements of Operations Data:					
Revenues	$ 866,542	$ 1,563,126	$ 1,551,701	$ 1,320,303	$ 385,910
(Loss) Income from Operations	(1,362,605)	(1,703,693)	398,959	555,781	(862,422)
Income Tax Expense (Benefit)	7,290	(7,563)	(69)	1,809	(2,913)
Net (Loss) Income Available to Common Stockholders	$ (1,625,133)	$ (2,002,358)	$ 430,560	$ 435,152	$ (979,709)
Net (Loss) Income Per Common Share—Basic:	$ (10.14)	$ (12.49)	$ 2.46	$ 2.42	$ (7.97)
Net (Loss) Income Per Common Share—Diluted:	$ (10.14)	$ (12.49)	$ 2.45	$ 2.41	$ (7.97)

	At December 31,				
	2020	2019	2018	2017	2016
	(In thousands)				
Selected Consolidated Balance Sheet Data:					
Total assets	$ 2,539,871	$ 3,882,819	$ 6,051,036	$ 5,807,752	$ 4,223,145
Total debt, including current maturities	$ 253,743	$ 1,978,651	$ 2,087,416	$ 2,038,943	$ 1,593,875
Total liabilities subject to compromise	$ 2,293,480	$ —	$ —	$ —	$ —
Total liabilities	$ 2,840,371	$ 2,568,227	$ 2,723,268	$ 2,706,138	$ 2,039,253
Stockholders' (deficit) equity	$ (300,500)	$ 1,314,592	$ 3,327,768	$ 3,101,614	$ 2,183,892

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis represents management's perspective of our business, financial condition and overall performance. This information is intended to provide investors with an understanding of our past performance, current financial condition and outlook for the future and should be read in conjunction with “Item 8. Financial Statements and Supplementary Data” of this report. The following discussion and analysis generally discusses 2020 and 2019 items and year-to-year comparisons between 2020 and 2019. Discussions of 2018 items and year-to-year comparisons between 2019 and 2018 that are not included in this Form 10-K can be found in "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" in Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2019.

Overview

We are an independent natural gas-weighted exploration and production company focused on the exploration, acquisition and production of natural gas, crude oil and NGL in the United States with primary focus in the Appalachia and Anadarko basins. Our principal properties are located in Eastern Ohio targeting the Utica formation and in central Oklahoma targeting the SCOOP Woodford and SCOOP Springer formations.

Voluntary Reorganization Under Chapter 11

On November 13, 2020, we and our subsidiaries filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the Southern District of Texas. The Chapter 11 Cases are being administered jointly under the caption*In re Gulfport Energy Corporation, et al.,* Case No. 20-35562 (DRJ). We continue to operate our businesses as "debtors-in-possession" under the jurisdiction of the Bankruptcy Court, in accordance with the applicable provisions of the Bankruptcy Code and the orders of the Bankruptcy Court.

The Bankruptcy Court has granted first- and second- day motions filed by us that were designed primarily to mitigate the impact of the Chapter 11 Cases on our operations, customers and employees. As a result, we are able to conduct normal business activities and pay all associated obligations for the period following the Bankruptcy Filing and are authorized to pay owner royalties, employee wages and benefits and certain vendors and suppliers in the ordinary course for goods and services provided. During the pendency of the Chapter 11 Cases, all transactions outside the ordinary course of business require the prior approval of the Bankruptcy Court.

For the duration of the Chapter 11 Cases, our operations and ability to develop and execute our business plan are subject to the risks and uncertainties associated with the Chapter 11 process as described in Item 1A. “Risk Factors.” As a result of these risks and uncertainties, the number of our shares of common stock and stockholders, assets, liabilities, officers and/or directors could be significantly different following the outcome of the Chapter 11 Cases, and the description of our operations, properties and capital plans included in this Form 10-K may not accurately reflect our operations, properties and capital plans following the Chapter 11 Cases.

During the Chapter 11 Cases, we expect our financial results to continue to be volatile as restructuring activities and expenses, contract terminations and rejections and claims assessments significantly impact our consolidated financial statements. As a result, our historical financial performance is likely not indicative of our financial performance after the date of the Bankruptcy Filing. In addition, we have incurred significant professional fees and other costs in connection with preparation for the Chapter 11 Cases and expect that we will continue to incur significant professional fees and costs throughout our Chapter 11 Cases.

See Note 2 of the notes to our consolidated financial statements included in Item 8 of Part II of this report for a complete discussion of the Chapter 11 Cases.

Delisting of our Common Stock from Nasdaq

On November 27, 2020, our common stock was suspended from trading on NASDAQ.On November 30, 2020, our common stock began trading on the OTC Pink Marketplace maintained by the OTC Markets Group, Inc. under the symbol “GPORQ". On February 2, 2021, NASDAQ filed a Form 25 delisting our common stock from trading on NASDAQ, which delisting became effective 10 days after the filing of the Form 25. In accordance with Rule 12d2-2 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), the de-registration of our common stock under section 12(b) of the Exchange Act became effective on February 12, 2021.

COVID-19 Pandemic and Impact on Global Demand for Oil and Natural Gas

In March 2020, the World Health Organization classified the outbreak of COVID-19 as a pandemic and recommended containment and mitigation measures worldwide. The measures have led to worldwide shutdowns and halting of commercial and interpersonal activity, as governments around the world imposed regulations in efforts to control the spread of COVID-19 such as shelter-in-place orders, quarantines, executive orders and similar restrictions.

We remain focused on protecting the health and well-being of our employees and the communities in which we operate while assuring the continuity of our business operations. We have implemented preventative measures and developed corporate and field response plans to minimize unnecessary risk of exposure and prevent infection. We have a crisis management team for health, safety and environmental matters and personnel issues, and we have established a COVID-19 Response Team to address various impacts of the situation, as they have been developing. We also have modified certain business practices (including remote working for our corporate employees and restricted employee business travel) to conform to government restrictions and best practices encouraged by the Centers for Disease Control and Prevention, the World Health Organization and other governmental and regulatory authorities.

In May 2020, we began our phased transition back to the office for our corporate employees. As part of this transition, we have put into place preventative measures to focus on social distancing and minimizing unnecessary risk of exposure. Such measures include, but are not limited to, daily health surveys, protective masks in public areas of the building, no outside visitors, limiting the number of employees on elevators and additional sanitizing. As of the date of this filing, we have transitioned a majority of our corporate employees back to the corporate office; however, we continue to provide a balanced work schedule that allows for a significant portion of the work week to be performed remotely. We will continue to monitor trends and governmental guidelines and may adjust our return to office plans accordingly to ensure the health and safety of our employees.

As a result of our business continuity measures, we have not experienced significant disruptions in executing our business operations during 2020. While we did not experience significant disruptions to our operations in 2020, we are unable to predict the impact on our business, including our cash flows, liquidity, and results of operations in future periods due to numerous uncertainties. There is considerable uncertainty regarding the extent to which COVID-19 will continue to spread and the extent and duration of governmental and other measures implemented to slow the spread of the virus, such as large-scale travel bans and restrictions, quarantines, shelter-in-place orders and business and government shutdowns. Restrictions of this nature may cause, us, our suppliers and other business counterparties to experience operational delays, or delays in the delivery of materials and supplies. We expect the principal areas of operational risk for us are the availability and reliability of service providers and potential supply chain disruption. Additionally, the operations of our midstream service providers, on whom we rely for the transmission, gathering and processing of a significant portion of our produced natural gas, NGL and oil, may be disrupted or suspended in response to containing the outbreak, or the difficult economic environment may lead to the bankruptcy or closing of the facilities and infrastructure of our midstream service providers. This may result in substantial discount in the prices we receive for our produced natural gas, NGL and oil or result in the shut-in of producing wells or the delay or discontinuance of development plans for our properties.

One of the impacts of the pandemic has been a significant reduction in global demand for oil and natural gas. The significant decline in demand has been met with a sharp decline in oil prices following the announcement of price reductions and production increases in March 2020 by members of the Organization of Petroleum Exporting Countries, and other foreign, oil-exporting countries. The resulting supply/demand imbalance is having disruptive impacts on the oil and natural gas exploration and production industry and on other industries that serve exploration and production companies. These industry conditions, coupled with those resulting from the COVID-19 pandemic, has led to significant global economic contraction generally and in our industry in particular. We expect to see continued volatility in oil and natural gas prices for the foreseeable future, which may, over the long term, adversely impact our business. Continued depressed demand or prices for oil and natural gas would have a material adverse effect on our business, cash flows, liquidity, financial condition and results of operations.

Because of the sharp decline in oil prices since early March 2020, we chose to shut in a portion of our operated low margin, liquids-weighted production during the second quarter of 2020, largely consisting of legacy vertical production in the SCOOP. We also experienced shut-ins across both the SCOOP and Utica from our non-operated partners. All liquids-weighted volumes on both our operated assets and those of our non-operated partners have returned to production. A sharp decline in prices or a prolonged depressed environment may result in additional future shut ins. In addition, the COVID-19 pandemic creates risks of delays in new drilling and completion activities that could negatively impact us, our non-operated partners or our service providers.

In June 2020, in response to the depressed commodity price environment, we announced tiered salary reductions for most employees, senior management team and our Board of Directors as well as select furloughs to reduce costs and preserve liquidity. The employee salary reductions were re-instated in late September, while the senior management and Board of Directors reductions were re-instated at December 31, 2020. In addition, we reduced our workforce by approximately 10% in the third quarter of 2020 to align our workforce to the current and forecasted needs of operating our business plans.

We cannot predict the full impact that COVID-19 or the significant disruption and volatility currently being experienced in the oil and natural gas markets will have on our business, cash flows, liquidity, financial condition and results of operations at this time, due to numerous uncertainties. The ultimate impacts will depend on future developments, including, among others, the ultimate geographic spread of the virus, the consequences of governmental and other measures designed to prevent the spread of the virus, the development and distribution of effective treatments and vaccines, the duration of the outbreak, actions taken by members of OPEC and other foreign, oil-exporting countries, governmental authorities, customers, suppliers and other thirds parties, workforce availability, and the timing and extent to which normal economic and operating conditions resume. While we have seen meaningful recovery in demand during the second half of the year, significant uncertainty remains regarding the duration and extent of the impact of the pandemic on the energy industry, including demand and commodities pricing, although we expect to see further recovery as vaccines are distributed and more normal societal activity resumes. For additional discussion regarding risks associated with the COVID-19 pandemic, see Item 1A. “Risk Factors” in this report.

2020 Operational and Financial Highlights

In the current depressed commodity price environment and period of economic uncertainty, we took the following operational and financial measures in 2020 to improve our balance sheet and preserve liquidity:

- Reduced 2020 capital spending by more than 50% as compared to 2019;
- Divested our SCOOP water infrastructure assets to a third-party water service provider for $50 million;
- Reduced long-term debt related to our senior unsecured notes by $73.3 million through discounted repurchases;
- Reduced certain corporate general and administrative costs through pay reductions, furloughs and reductions in force;
- Evaluated economics across our portfolio and shut-in certain non-economical production in the second quarter of 2020;
- Continued to significantly improve operational efficiencies and reduce drilling and completion costs in both our SCOOP and Utica operating areas. In the Utica, our average spud to rig release time was 18.7 days in 2020, which was a 5% improvement from 2019 levels. In the SCOOP, our average spud to rig release time was 35.5 days, representing a 35% improvement compared to 2019 levels.

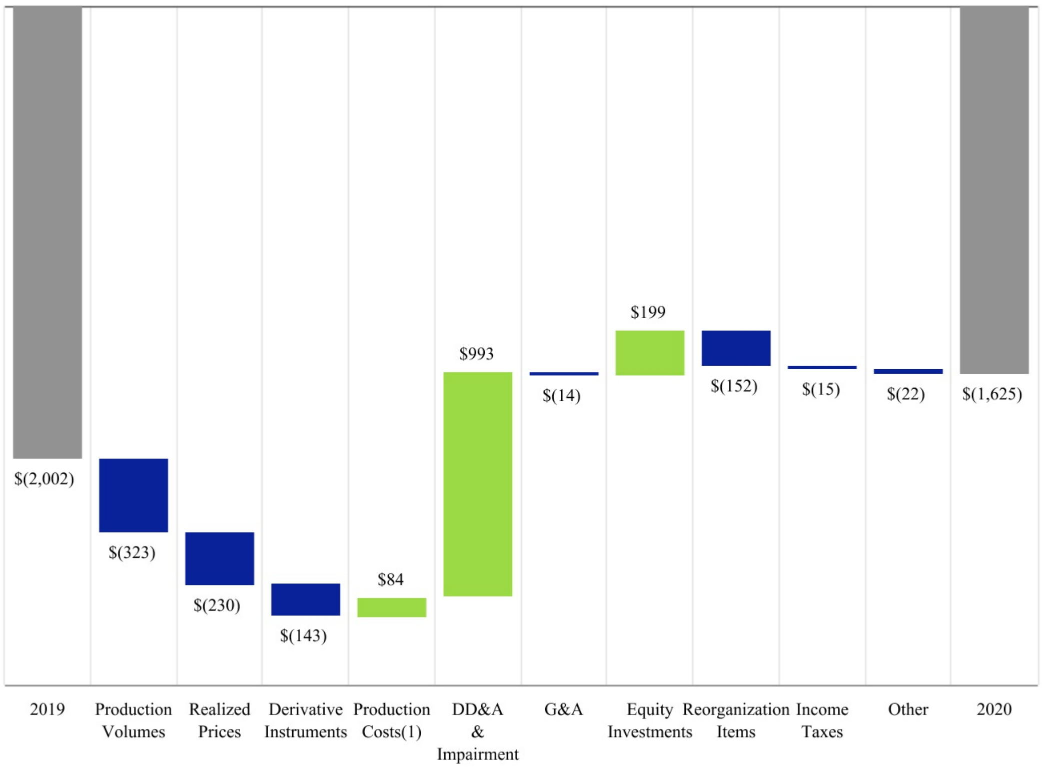
Although management's actions listed above have helped to improve the company's liquidity and leverage profile, continued macro headwinds including the depressed state of energy capital markets and extraordinarily low commodity price environment presented significant risks to the Company's ability to fund its operations going forward. On October 8, 2020, the borrowing base under our revolving credit facility was reduced for the second time in 2020 from $700 million to $580 million, thereby significantly reducing available liquidity. Considering the facts above, we elected not to make interest payments of $17.4 million due October 15, 2020 and $10.8 million due November 2, 2020 on our 2024 Notes and 2023 Notes, respectively. On November 13, 2020, we filed voluntary petitions for relief under Chapter 11 as discussed above.

Results of Operations

Comparison of the Years Ended December 31, 2020 and December 31, 2019

We reported a net loss of $1.6 billion for the year ended December 31, 2020 as compared to a net loss of $2.0 billion for the year ended December 31, 2019. The graph below shows the change in the net loss from the year ended December 31, 2020 to the year ended December 31, 2019. The material changes are further discussed by category on the following pages. Some totals and changes throughout below section may not sum or recalculate due to rounding.

Net Loss
($ In Millions)



[(1)] Includes lease operating expenses, taxes other than income and midstream, gathering and processing expenses.

Natural Gas, Oil and NGL Sales

	Years Ended December 31,		
	2020	2019	change
	(In thousands, unless otherwise stated)		
Natural gas (MMcf/day)			
Utica production volumes	795	1,062	(25)%
SCOOP production volumes	147	194	(24)%
Other production volumes[3]	—	—	(64)%
Total production volumes	943	1,255	(25)%
Total sales	$ 671,535	$ 1,135,381	(41)%
Average price without the impact of derivatives ($/Mcf)	$ 1.95	$ 2.48	(21)%
Impact from settled derivatives ($/Mcf)[1]	$ 0.33	$ 0.23	43 %
Average price, including settled derivatives ($/Mcf)	$ 2.28	$ 2.71	(16)%
Oil and condensate (MBbl/day)			
Utica production volumes	1	1	59 %
SCOOP production volumes	4	4	(14)%
Other production volumes[3]	—	1	(94)%
Total production volumes	5	6	(18)%
Total sales	$ 62,902	$ 117,937	(47)%
Average price without the impact of derivatives ($/Bbl)	$ 34.88	$ 53.95	(35)%
Impact from settled derivatives ($/Bbl)[2]	$ 25.76	$ 1.86	1285 %
Average price, including settled derivatives ($/Bbl)	$ 60.64	$ 55.81	9 %
NGL (MBbl/day)			
Utica production volumes	3	5	(41)%
SCOOP production volumes	8	9	(12)%
Other production volumes[3]	—	—	(50)%
Total production volumes	11	14	(22)%
Total sales	$ 66,814	$ 101,448	(34)%
Average price without the impact of derivatives ($/Bbl)	$ 16.86	$ 19.99	(16)%
Impact from settled derivatives ($/Bbl)	$ (0.04)	$ 2.79	(101)%
Average price, including settled derivatives ($/Bbl)	$ 16.82	$ 22.78	(26)%
Total (MMcfe/day)			
Utica production volumes	820	1,095	(25)%
SCOOP production volumes	217	274	(21)%
Other production volumes[3]	—	6	(94)%
Total production volumes	1,037	1,375	(25)%
Total sales	$ 801,251	$ 1,354,766	(41)%
Average price without the impact of derivatives ($/Mcfe)	$ 2.11	$ 2.70	(22)%
Impact from settled derivatives ($/Mcfe)	$ 0.42	$ 0.24	75 %
Average price, including settled derivatives ($/Mcfe)	$ 2.53	$ 2.94	(14)%

(1) In November 2020, the Company early terminated certain gas fixed price swaps which resulted in a cash payment of $60.2 million.
(2) In April 2020, the Company early terminated certain oil fixed price swaps which resulted in a cash receipt of $40.5 million.
(3) Includes Niobrara, Bakken and Southern Louisiana.

In 2020, our total unhedged natural gas, oil and NGL revenues decreased approximately $553.5 million, or 41%, as compared to 2019. A 25% decrease in total production volumes accounted for $323 million of lower natural gas, oil and NGL revenues. The decrease is production was primarily related to our significantly lower capital program beginning in the fourth quarter of 2019 into 2020. The remainder of the decrease in natural gas, oil and NGL revenues is related to a significant decrease in the realized prices for each of our commodities as compared to 2019 realized prices driven by depressed commodity market conditions.

The total natural gas, oil and NGL volumes hedged for 2020 and 2019 represented approximately 70% and 96%, respectively, of our total sales volumes for the applicable year.

Natural Gas, Oil and NGL Derivatives

	Years Ended December 31,	
	2020	2019
	($ In thousands)	
Natural gas derivatives - fair value (losses) gains	$ (89,310)	$ 89,576
Natural gas derivatives - settlement gains	113,075	104,874
Total gains on natural gas derivatives	23,765	194,450
Oil and condensate derivatives - fair value (losses) gains	(2,952)	2,952
Oil and condensate derivatives - settlement gains	46,462	4,083
Total gains on oil and condensate derivatives	43,510	7,035
NGL derivatives - fair value losses	(461)	(7,541)
NGL derivatives - settlement (losses) gains	(142)	14,173
Total (losses) gains on NGL derivatives	(603)	6,632
Contingent consideration arrangement - fair value (losses) gains	(1,381)	243
Total gains on natural gas, oil and NGL derivatives	$ 65,291	$ 208,360

Settlement gains (losses) in the table above represent realized cash gains or losses to the instruments described in Note 13 to our consolidated financial statements. Our hedging program provided cash settlements of $159.4 million in 2020 as compared to $123.1 million in 2019.

Lease Operating Expenses

	Years Ended December 31,		
	2020	2019	change
	($ In thousands, except per unit)		
Lease operating expenses			
Utica	$ 40,071	$ 50,832	(21)%
SCOOP	14,156	18,249	(22)%
Other[1]	8	4,415	(100)%
Total lease operating expenses	$ 54,235	$ 73,496	(26)%
Lease operating expenses per Mcfe			
Utica	$ 0.13	$ 0.13	5 %
SCOOP	0.18	0.18	(3)%
Other[1]	0.06	2.18	(97)%
Total lease operating expenses per Mcfe	$ 0.14	$ 0.15	(2)%

(1) Includes Niobrara, Bakken and Southern Louisiana

The decrease in total LOE in 2020 was primarily driven by the 25% decrease in our production resulting from production declines from our Utica and SCOOP properties as a result of reduced development activities in addition to the divestiture of our Southern Louisiana properties as discussed in Note 3 to our consolidated financial statements. LOE on a per unit basis was slightly lower for the year ended December 31, 2020 as compared to 2019 as a result of increased focus on reducing lease operating expenses within the organization as well as the divestiture of the Southern Louisiana properties which had a higher operating cost structure relative to our other assets.

Taxes Other Than Income

	Years Ended December 31,		
	2020	2019	change
	($ In thousands, except per unit)		
Production taxes	$ 17,511	$ 28,571	(39)%
Property taxes	$ 9,510	$ 9,470	— %
Other	$ 1,488	$ 2,469	(40)%
Total Taxes other than income	$ 28,509	$ 40,510	(30)%
Production taxes per Mcfe	$ 0.05	$ 0.06	(19)%

The decrease in production taxes in 2020 was primarily related to a decrease in revenue and production in 2020 as compared to 2019.

Midstream Gathering and Processing Expenses

	Years Ended December 31,		
	2020	2019	change
	($ In thousands, except per unit)		
Midstream gathering and processing expenses	$ 456,318	$ 508,843	(10)%
Midstream gathering and processing expenses per Mcfe	$ 1.20	$ 1.01	19 %

The decrease in midstream gathering and processing expenses in 2020 was primarily related to the 25% decrease in our production volumes. The increase in per unit midstream gathering and processing expenses in 2020 is primarily related to Utica production volumes falling below the minimum volume commitments we have on certain of our firm transportation agreements with pipeline companies and the resulting deficiency payments.

Depreciation, Depletion and Amortization

	Years Ended December 31,		
	2020	2019	change
	($ In thousands, except per unit)		
Depreciation, depletion and amortization of oil and gas properties	$ 229,703	$ 538,894	(57)%
Depreciation, depletion and amortization of other property and equipment	$ 10,041	$ 11,214	(10)%
Total Depreciation, depletion and amortization	$ 239,744	$ 550,108	(56)%
Depreciation, depletion and amortization per Mcfe	$ 0.63	$ 1.10	(42)%

The decrease in DD&A in 2020 was due to a decrease in the depletion rate, driven primarily by impairment charges in 2019 and 2020, which decreased the depletion base. The decrease was further driven by an approximate 25% decrease in production.

Impairment of Oil and Gas Properties. During 2020, we had $1.4 billion oil and natural gas properties impairment charges related primarily to the continued decline in commodity prices, compared to $2.0 billion impairment charges of oil and gas properties in 2019.

General and Administrative Expenses

	Years Ended December 31,		
	2020	2019	change
	($ In thousands, except per unit)		
General and administrative expenses, gross	$ 95,904	$ 86,854	10 %
Reimbursed from third parties	(11,567)	(11,173)	4 %
Capitalized general and administrative expenses	(25,008)	(30,139)	(17)%
General and administrative expenses, net	$ 59,329	$ 45,542	30 %
General and administrative expenses, net per Mcfe	$ 0.16	$ 0.09	72 %

The increase in general and administrative expenses, gross in 2020 was primarily due to an increase in non-recurring legal and consulting charges and compensation expense as a result of cash retention incentives paid to our employees during the third quarter of 2020. See Note 8 to our consolidated financial statements for further discussion on these cash retention incentive payments. This increase was partially offset by lower salary costs resulting from the reduction in workforce that was completed in the fourth quarter of 2019 and third quarter of 2020 as well as certain furloughs and pay reductions as discussed in the overview. The decrease in capitalized general and administrative expenses in 2020 was due to lower development activities for 2020 as compared to 2019.

Restructuring and Liability Management Expenses. In the third quarter of 2020 and fourth quarter of 2019, the Company announced and completed workforce reductions representing approximately 10% and 13%, respectively, of its headcount. In connection with the reduction, the Company incurred total restructuring charges of approximately $1.5 million and $4.6 million, primarily consisting of one-time employee-related termination benefits, for 2020 and 2019, respectively. Additionally, the Company incurred charges related to financial and legal advisors engaged to assist with the evaluation of a range of liability management alternatives during 2020 prior to the filing of the Chapter 11 Cases. While we expect to continue to incur significant financial and legal advisor fees throughout the Chapter 11 process, these costs will be presented in *Reorganization Items, Net* in our consolidated statements of operations.

Accretion Expense. Accretion expense decreased to $3.1 million for the 2020 from $3.9 million for the 2019, primarily as a result of asset divestitures discussed in Note 3.

Interest Expense

	Years Ended December 31, 2020	2019
	($ In thousands, except per unit)	
Interest expense on senior notes	98,528	125,687
Interest expense on pre-petition revolving credit facility	14,224	12,088
Interest expense on building loan and other	1,861	1,055
Capitalized interest	(907)	(3,372)
Interest on DIP credit facility	810	—
Amortization of loan costs	5,563	6,328
Total interest expense	$ 120,079	$ 141,786
Interest expense per Mcfe	$ 0.32	$ 0.28
Weighted average debt outstanding under revolving credit facility	$ 193,182	$ 161,416

The decrease in interest on senior notes in 2020 as compared to 2019 is primarily due to the Chapter 11 proceedings. As of the Petition Date, we are not paying or recognizing interest expense on any of our outstanding debt other than any post-petition amounts drawn on the Pre-Petition Revolving Credit Facility and the DIP Credit Facility.

Gain on Debt Extinguishment. In July of 2019, our Board of Directors authorized $100 million of cash to be used to repurchase its senior notes in the open market at discounted values to par. In December 2019, our Board of Directors increased the authorized size of the senior note repurchase program to $200 million in total. During 2020, we repurchased in the open market $73.3 million aggregate principal amount of our outstanding Senior Notes for $22.8 million in cash and recognized a $49.6 million gain on debt extinguishment. During 2019, we repurchased $190.1 aggregate principal amount of our outstanding Senior Notes for $138.8 million in cash and recognized a $48.6 million gain on debt extinguishment.

Equity Investments

	Years Ended December 31, 2020	2019	change
	($ In thousands)		
Loss (income) from equity method investments, net	$ 11,055	$ 210,148	(95)%

For 2020, the loss from equity method investments stems primarily from a $10.6 million loss related to our investment in Mammoth Energy, with no impairments recorded. The loss from equity method investments during 2019 was primarily the result of a $160.8 million impairment loss related to our investment in Mammoth Energy and a $32.4 million impairment loss related to our investment in Grizzly. See Note 5 to our consolidated financial statements for further discussion on our equity investments.

Reorganization Items, Net. The following table summarizes the components in reorganization items, net included in our consolidated statements of operations for the year ended December 31, 2020:

	Year Ended December 31, 2020
	(in thousands)
Adjustment for allowed claims	$ 104,943
Legal and professional fees	24,905
Write off of unamortized debt issuance costs	21,956
DIP credit facility financing fees	2,988
Gain on settlement of pre-petition accounts payable	(2,433)
Reorganization items, net	$ 152,359

We expect to incur significant legal and professional fees related to our ongoing Chapter 11 case in 2021.

Other Expense, Net

	Years Ended December 31,		
	2020	2019	change
	($ In thousands)		
Other expense, net	$ 21,738	$ 3,725	484 %

The increase in other expense in 2020 is primarily the result of a $16.6 million loss on the change in fair value of our contingent consideration agreement related to the sale of our SCOOP water infrastructure assets to a third-party water service provider. See Note 15 to our consolidated financial statements for further discussion on our contingent consideration agreement.

Income Taxes

	Years Ended December 31,		
	2020	2019	change
	($ In thousands)		
Income tax expense (benefit)	$ 7,290	$ (7,563)	(196)%

The change in income tax in 2020 is primarily the result of the recognition of a valuation allowance against a state deferred tax asset. At December 31, 2020, we had a federal net operating loss carryforward of $1.9 billion, in addition to numerous temporary differences, which gave rise to a net deferred tax asset, and a valuation allowance of $985.5 million maintained against the net deferred asset.

Liquidity and Capital Resources

Overview. Historically, our primary sources of capital funding and liquidity have been our operating cash flow, borrowings under our Pre-Petition Revolving Credit Facility and issuances of equity and debt securities. Our ability to issue additional indebtedness, dispose of assets or access the capital markets may be substantially limited or nonexistent during the Chapter 11 Cases and will require court approval in most instances. Accordingly, our liquidity will depend mainly on cash generated from operating activities and available funds under the DIP Credit Facility as discussed below.

Filing of the Chapter 11 Cases constituted an event of default with respect to certain of our secured and unsecured debt obligations. As a result of the Chapter 11 Cases, the principal and interest due under these debt instruments became immediately due and payable. However, the creditors are stayed from taking any action as a result of the default under Section 362 of the Bankruptcy Code.

As of December 31, 2020, we had a cash balance of $89.9 million compared to $6.1 million as of December 31, 2019, and a net working capital deficit of $100.5 million as of December 31, 2020, compared to a net working capital deficit of $145.3 million as of December 31, 2019. As of December 31, 2020, our working capital deficit includes $253.7 million of debt due in the next 12 months. Our total principal debt as of December 31, 2020 was $2.3 billion compared to $2.0 billion as of December 31, 2019. Additionally, as of December 31, 2020, we had outstanding borrowings of $157.5 million on our DIP credit facility with $105.0 million of incremental borrowing capacity. See Note 6 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of our debt obligations, including principal and carrying amounts of our notes.

We believe our cash flow from operations, borrowing capacity under the DIP Credit Facility and cash on hand will provide sufficient liquidity during the Chapter 11 process. We expect to incur significant costs related to our ongoing Chapter 11 Cases in 2021, including fees for legal, financial and restructuring advisors to the Company, certain of our creditors and royalty interest owners. Therefore, our ability to obtain confirmation of the Plan in a timely manner is critical to ensuring our liquidity is sufficient during the bankruptcy process.

Our ability to continue as a going concern is contingent on our ability to comply with the financial and other covenants contained in our DIP Credit Facility, the Bankruptcy Court's approval of the Plan and our ability to successfully implement the Plan and obtain exit financing, among other factors. As a result of the Bankruptcy Filing, the realization of assets and the satisfaction of liabilities are subject to uncertainty. While operating as debtors-in-possession under Chapter 11, we may settle liabilities, subject to the approval of the Bankruptcy Court or as otherwise permitted in the ordinary course of business (and subject to restrictions contained in the DIP Credit Facility), for amounts other than those reflected in the accompanying consolidated financial statements. Further, the Plan could materially change the amounts and classifications of assets and liabilities reported in the consolidated financial statements.

Debtor-In-Possession Credit Facility. Pursuant to the RSA, the Consenting RBL Lenders have agreed to provide the Company with a senior secured superpriority debtor-in-possession revolving credit facility in an aggregate principal amount of $262.5 million consisting of $105 million of new money and $157.5 million to roll up a portion of the existing outstanding obligations under the Pre-Petition Revolving Credit Facility. The proceeds of the DIP Credit Facility may be used for, among other things, post-petition working capital, permitted capital investments, general corporate purposes, letters of credit, administrative costs, premiums, expenses and fees for the transactions contemplated by the Chapter 11 Cases and payment of court approved adequate protection obligations.

Advances under our DIP Credit Facility may be in the form of either base rate loans or eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate of 3.50%, plus (2) the base rate. The interest rate for eurodollar loans is equal to (1) the applicable rate of 4.50%, plus (2) the highest of: (a) 1% or (b) the eurodollar rate. As of December 31, 2020, amounts borrowed under our DIP Credit Facility bore interest at the weighted average rate of 5.50%.

The DIP Credit Facility includes negative covenants that, subject to significant exceptions, limit our ability and the ability of our restricted subsidiaries to, among other things, (i) create liens on assets, property revenues, (ii) make investments, (iii) incur additional indebtedness, (iv) engage in mergers, consolidations, liquidations and dissolutions, (v) sell assets, (vi) pay dividends and distributions or repurchase capital stock, (vii) cease for any reason to be the operator of its properties, (viii) enter into letters of credit without prior written consent, (ix) enter into certain commodity hedging contracts except commodity hedging contracts with terms approved by the Bankruptcy Court in the hedging order or certain interest rate contracts, (x) change lines of business, (xi) engage in certain transactions with affiliates and (xii) incur more than a certain amount in capital expenditures in any calendar month. The DIP Credit Facility includes certain customary representations and warranties, affirmative covenants and events of default, including but not limited to defaults on account of nonpayment, breaches of representations and warranties and covenants, certain bankruptcy-related events, certain events under ERISA, material judgments and a change in control. If an event of default occurs, the lenders under the DIP Credit Facility will be entitled to take various actions, including the acceleration of all amounts due under the DIP Credit Facility and all actions permitted to be taken under the loan documents or application of law. In addition, the DIP Credit Facility is subject to various other financial performance covenants, including compliance with certain financial metrics and adherence to a budget approved by our DIP Credit Facility lenders.

Pre-Petition Revolving Credit Facility. We have entered into a senior secured revolving credit facility agreement, as amended, with The Bank of Nova Scotia, as the lead arranger and administrative agent and certain lenders from time to time party thereto. The credit agreement provides for a maximum borrowing base amount of $580 million and matures on December 31, 2021. The $292.9 million of outstanding borrowings under the Pre-Petition Revolving Credit Facility as of December 31, 2020 that were not rolled up into the DIP Credit Facility will remain outstanding throughout the Chapter 11 Cases and will continue to accrue interest on amounts drawn after the Petition Date. Additionally, as of December 31, 2020, we had an aggregate of $147.5 million of letters of credit outstanding under our Pre-Petition Revolving Credit Facility. This facility is secured by substantially all of our assets. Our wholly-owned subsidiaries, excluding Grizzly Holdings and Mule Sky, guarantee our obligations under our revolving credit facility.

Advances under our Pre-Petition Revolving Credit Facility may be in the form of either base rate loans or eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 0.25% to 1.25%, plus (2) the highest of: (a) the federal funds rate plus 0.50%, (b) the rate of interest in effect for such day as publicly announced from time to time by the administrative agent as its "prime rate," and (c) the eurodollar rate for an interest period of one month plus 1.00%. The interest rate for eurodollar loans is equal to (1) the applicable rate, which ranges from 1.25% to 2.25%, plus (2) the London interbank offered rate that appears on pages LIBOR01 or LIBOR02 of the Reuters screen that displays such rate for deposits in U.S. dollars, or, if such rate is not available, the rate as administered by ICE Benchmark Administration (or any other person that takes over administration of such rate) per annum equal to the offered rate on such other page or other service that displays an average London interbank offered rate as administered by ICE Benchmark Administration (or any other person that takes over the administration of such rate) for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the administrative agent shall inquire as the "London Interbank Offered Rate" for deposits in U.S. dollars. As of December 31, 2020, amounts borrowed under our revolving credit facility bore interest at the weighted average rate of 3.15%.

Senior Notes. In April 2015, we issued an aggregate of $350.0 million in principal amount of our 2023 Notes. Interest on these senior notes accrues at a rate of 6.625% per annum on the outstanding principal amount thereof, payable semi-annually on May 1 and November 1 of each year. As of December 31, 2020, after giving effect to open market repurchases of these 2023 Notes, $324.6 million principal amount remained outstanding. The 2023 Notes mature on May 1, 2023.

On October 14, 2016, we issued an aggregate of $650.0 million in principal amount of our 2024 Notes. Interest on the 2024 Notes accrues at a rate of 6.000% per annum on the outstanding principal amount thereof, payable semi-annually on April 15 and October 15 of each year. As of December 31, 2020, after giving effect to open market repurchases of these 2024 Notes, $579.6 million principal amount remained outstanding. The 2024 Notes mature on October 15, 2024.

On December 21, 2016, we issued an aggregate of $600.0 million in principal amount of our 2025 Notes. Interest on the 2025 Notes accrues at a rate of 6.375% per annum on the outstanding principal amount thereof, payable semi-annually on May 15 and November 15 of each year. As of December 31, 2020, after giving effect to open market repurchases of these 2025 Notes, $507.9 million principal amount remained outstanding. The 2025 Notes mature on May 15, 2025.

On October 11, 2017, we issued $450.0 million in aggregate principal amount of our 2026 Notes. Interest on the 2026 Notes accrues at a rate of 6.375% per annum on the outstanding principal amount thereof, payable semi-annually on January 15 and July 15 of each year. As of December 31, 2020, after giving effect to open market repurchases of these 2026 Notes, $374.6 million principal amount remained outstanding. The 2026 Notes mature on January 15, 2026.

All amounts outstanding on our Senior Notes have been classified as liabilities subject to compromise on the accompanying consolidated balance sheet as of December 31, 2020.

During the year ended December 31, 2020, we used borrowings under our revolving credit facility to repurchase in the open market approximately $73.3 million aggregate principal amount of our outstanding Notes for $22.8 million. We recognized a $49.6 million gain on debt extinguishment, which included retirement of unamortized issuance costs and fees associated with the repurchased debt.

Building Loan. On June 4, 2015, we entered into a loan for the construction of our corporate headquarters in Oklahoma City, which was substantially completed in December 2016. Interest accrues daily on the outstanding principal balance at a fixed rate of 4.50% per annum. The building loan matures on June 4, 2025. As of December 31, 2020, the total borrowings under the building loan were approximately $21.9 million, which has been classified as liabilities subject to compromise on the accompanying consolidated balance sheet as of December 31, 2020.

Supplemental Guarantor Financial Information. The 2023 Notes, 2024 Notes, 2025 Notes and 2026 Notes are guaranteed on a senior unsecured basis by all existing consolidated subsidiaries that guarantee our secured revolving credit facility or certain other debt (the "Guarantors"). The Senior Notes are not guaranteed by Grizzly Holdings or Mule Sky, LLC (the "Non-

Guarantors”). The Guarantors are 100% owned by the Parent, and the guarantees are full, unconditional, joint and several. There are no significant restrictions on the ability of the Parent or the Guarantors to obtain funds from each other in the form of a dividend or loan. The guarantees rank equally in the right of payment with all of the senior indebtedness of the subsidiary guarantors and senior in the right of payment to any future subordinated indebtedness of the subsidiary guarantors. The Senior Notes and the guarantees are effectively subordinated to all of our and the subsidiary guarantors' secured indebtedness (including all borrowings and other obligations under our amended and restated credit agreement) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated to all indebtedness and other liabilities of any of our subsidiaries that do not guarantee the Notes. Effective June 1, 2019, the Parent contributed interests in certain oil and gas assets and related liabilities to certain of the Guarantors.

SEC Regulation S-X Rule 13-01 requires the presentation of "Summarized Financial Information" to replace the "Condensed Consolidating Financial Information" required under Rule 3-10. Rule 13-01 allows the omission of Summarized Financial Information if assets, liabilities and results of operations of the Guarantors are not materially different than the corresponding amounts presented in our consolidated financial statements. The Parent and Guarantor subsidiaries comprise our material operations. Therefore, we concluded that the presentation of the Summarized Financial Information is not required as our Summarized Financial Information of the Guarantors is not materially different from our consolidated financial statements.

Derivatives and Hedging Activities. We seek to mitigate risks related to unfavorable changes in natural gas, oil and NGL prices, which are subject to significant and often volatile fluctuation, by entering into over-the-counter fixed price swaps, basis swaps, collars and various types of option contracts. These contracts allow us to mitigate the impact of declines in future natural gas, oil and NGL prices by effectively locking in floor price for a certain level of our production. However, these hedge contracts also limit the benefit to us in periods when the future market prices of natural gas, oil and NGL that are higher than the hedged prices.

As of December 31, 2020, we had the following open natural gas derivative instruments (we had no oil or NGL derivative instruments in place):

Year	Type of Derivative Instrument	Index	Daily Volume (MMBtu/day)	Weighted Average Price
2021	Swaps	NYMEX Henry Hub	410,000	$2.75
2021	Basis Swaps	Rex Zone 3	35,000	$(0.21)
2021	Costless Collars	NYMEX Henry Hub	250,000	$2.46/$2.81
2021	Basis Swaps	Tetco M2	60,000	$(0.67)
2022	Sold Call Options	NYMEX Henry Hub	153,000	$2.90
2022	Costless Collars	NYMEX Henry Hub	20,000	$2.80/$3.40
2023	Sold Call Options	NYMEX Henry Hub	628,000	$2.90

See Note 13 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of derivatives and hedging activities.

Subsequent to December 31, 2020 and as of March 1, 2021, we entered into the following natural gas, oil, and NGL derivative contracts as we work toward fulfilling minimum hedging requirements as provided for in the RSA:

Period	Type of Derivative Instrument	Index	Daily Volume(1)	Weighted Average Price
July 2021 - December 2021	Swaps	NYMEX WTI	2,250	$53.07
July 2021 - December 2021	Swaps	Mont Belvieu C3	3,100	$27.80
January 2022 - June 2022	Swaps	Mont Belvieu C3	1,000	$27.30
April 2021 - May 2021	Basis Swaps	Tetco M2	36,443	$(0.61)
February 2021 - October 2021	Basis Swaps	Rex Zone 3	94,505	$(0.22)
July 2021 - December 2021	Costless Collars	NYMEX Henry Hub	210,000	$2.67/$3.15
January 2022 - March 2022	Costless Collars	NYMEX Henry Hub	340,000	$2.82/$3.40

(1) Volume units for gas instruments are presented as MMBtu/day while oil and NGL is presented in Bbls/day.

Contractual and Commercial Obligations. The following table sets forth our contractual and commercial obligations at December 31, 2020:

Contractual Obligations	Payment due by period				
	Total	2021	2022-2023	2024-2025	2026 and Thereafter
	(In thousands)				
Long-term debt(1):					
Principal	$ 2,258,962	$ 451,159	$ 326,003	$ 1,107,183	$ 374,617
Interest(2)	518,752	184,106	212,606	121,111	929
Firm transportation and gathering contracts(3)	3,774,725	370,343	760,150	631,113	2,013,119
Operating lease liabilities(4)	342	117	195	30	—
Total contractual cash obligations(5)	$ 6,552,781	$ 1,005,725	$ 1,298,954	$ 1,859,437	$ 2,388,665

(1) The maturities of our debt obligations and associated interest reflect their original expiration dates and do not reflect any acceleration due to any events of default pertaining to these obligations. See Note 6 of the notes to our consolidated financial statements included in Item 8 of this report for a description of our long-term debt.
(2) Includes all contractual interest on amounts classified as liabilities subject to compromise, including interest accrued on Senior Notes as of the Petition Date.
(3) Our commitments under our firm transportation and gathering contracts do not reflect contracts expected to be rejected through our Chapter 11 proceedings. See Note 17 of the notes to our consolidated financial statements included in Item 8 of this report for a description of our firm transportation and gathering contracts.
(4) See Note 10 of the notes to our consolidated financial statements included in Item 8 of this report for a description of our operating lease liabilities.
(5) This table does not include derivative liabilities or the estimated discounted cost for future abandonment of oil and natural gas properties. See Notes 13 and 4 of the notes to our consolidated financial statements included in Item 8 of this report, respectively.

Off-balance Sheet Arrangements. We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2020, our material off-balance sheet arrangements and transactions include $147.5 million in letters of credit outstanding against our revolving credit facility and $111.4 million in surety bonds issued. Both the letters of credit and surety bonds are being used as financial assurance on certain firm transportation agreements. There are no other transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of our capital resources.

Capital Expenditures. Our capital commitments have been primarily for the execution of our operations. Our capital investment strategy is focused on prudently developing our existing properties in an effort to generate sustainable cash flow considering current and forecasted commodity prices.

We continually monitor market conditions and are prepared to adjust our development program if commodity prices dictate. We believe our cash flow from operations, borrowing capacity under the DIP Credit Facility and cash on hand will provide sufficient liquidity during the Chapter 11 process. We expect to incur significant costs associated with our ongoing Chapter 11 Cases in 2021, including fees for legal, financial and restructuring advisors to the Company, certain of our creditors and royalty interest owners. Therefore, our ability to obtain confirmation of the Plan in a timely manner is critical to ensuring our liquidity is sufficient during the bankruptcy process.

Commodity Price Risk. The volatility of the energy markets makes it extremely difficult to predict future oil and natural gas price movements with any certainty. During 2019, WTI prices ranged from $46.31 to $66.24 per barrel and the Henry Hub spot market price of natural gas ranged from $1.75 to $4.25 per MMBtu. During 2020, WTI prices ranged from $(36.98) to $63.27 per barrel and the Henry Hub spot market price of natural gas ranged from $1.33 to $3.14 per MMBtu. If the prices of oil and natural gas decline further, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected. In addition, lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development activities are curtailed, full cost accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. Reductions in commodity prices and/or our reserves could also negatively impact the borrowing base under our revolving credit facility, which could limit our liquidity and ability to fund development activities.

See Item 7A. "Quantitative and Qualitative Disclosures about Market Risk" for information regarding our open fixed price swaps at December 31, 2020.

Cash Flow from Operating Activities. Net cash flow provided by operating activities was $95.3 million for the year ended December 31, 2020 as compared to $724.0 million for 2019. This decrease was primarily the result of a decrease in cash receipts from our oil and natural gas purchasers due to a 41% decrease in net natural gas, oil and NGL sales excluding the impact of derivatives and, to a lesser extent, reorganization items related to our Chapter 11 Cases.

Divestitures. During 2020, we divested certain non-core assets and interests in operated and non-operated oil and natural gas properties for approximately cash proceeds of $51.0 million. Proceeds from these transactions were primarily used to repay debt and fund our development program. See Note 3 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion.

Uses of Funds. The following table presents the uses of our cash and cash equivalents for the years ended December 31, 2020 and 2019:

	Years Ended December 31, 2020	2019
	(In thousands)	
Oil and Natural Gas Property Expenditures:		
Drilling and completion costs	$ 321,811	$ 654,407
Leasehold acquisitions	18,135	39,664
Other	27,341	25,986
Total oil and natural gas property expenditures	$ 367,287	$ 720,057
Other Uses of Cash and Cash Equivalents		
Cash paid to repurchase senior notes	22,827	138,786
Cash paid to repurchase common stock	—	30,000
Additions to other property and equipment	799	5,021
DIP credit facility financing fees	2,988	—
Other	738	720
Total other uses of cash and cash equivalents	$ 27,352	$ 174,527
Total uses of cash and cash equivalents	$ 394,639	$ 894,584

Drilling and Completion Costs. During 2020, we spud 16 gross (16 net) wells and commenced sales from 25 gross (23.8 net) wells in the Utica for a total cost of approximately $192.2 million.

During 2020, we spud 10 gross (8.4 net) and commenced sales from 4 gross (3.8 net) wells in the SCOOP for a total cost of approximately $53.9 million. In addition, 19 gross (0.05 net) wells were spud and 12 gross (0.04 net) wells were turned to sales by other operators on our SCOOP acreage during 2020 for a total cost to us of approximately $0.6 million.

Drilling and completion costs presented in this section reflect incurred costs while drilling and completion costs presented above in *Uses of Funds* section reflect cash payments for drilling and completions.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States require us to make estimates and assumptions. The accounting estimates and assumptions we consider to be most significant to our financial statements are discussed below. Our management has discussed each critical accounting estimate with the Audit Committee of our Board of Directors.

The Company has applied FASB ASC Topic 852 -*Reorganizations* ("ASC 852") in preparing the consolidated financial statements, which specifies the accounting and financial reporting requirements for entities reorganizing through Chapter 11 bankruptcy proceedings. These requirements include distinguishing transactions associated with the reorganization separate from activities related to the ongoing operations of the business. Accordingly, pre-petition liabilities that may be impacted by the Chapter 11 proceedings have been classified as liabilities subject to compromise on the consolidated balance sheet as of December 31, 2020. Additionally, certain expenses, realized gains and losses and provisions for losses that are realized or incurred during the Chapter 11 Cases, including adjustments to the carrying value of certain indebtedness are recorded as reorganization items, net in the consolidated statements of operations for the year ended December 31, 2020. Refer to Note 2 for more information on the events of the bankruptcy proceedings as well as the accounting and reporting impacts of the reorganization.

Oil and Natural Gas Properties. We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including non-productive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and natural gas properties, are capitalized.

Under the full cost method, capitalized costs are amortized on a composite unit-of-production method based on proved oil and natural gas reserves. If we maintain the same level of production year over year, the depreciation, depletion and amortization expense may be significantly different if our estimate of remaining reserves or future development costs changes significantly.

We review the carrying value of our oil and natural gas properties under the full cost method of accounting prescribed by the SEC on a quarterly basis. This quarterly review is referred to as a ceiling test.

Two primary factors impacting this test are reserve estimates and the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended December 31, 2020. Downward revisions to estimates of oil and natural gas reserves and/or unfavorable prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. During the year ended December 31, 2020 we recorded impairments of our oil and natural gas properties in the amount of $1.4 billion compared to $2.0 billion during the year ended December 31, 2019. See Oil and Natural Gas Properties in Note 1 of the notes to our consolidated financial statements included in Item 8 of this report for further information on the full cost method of accounting.

Oil, Natural Gas and NGL Reserves. Estimates of oil and natural gas reserves and their values, future production rates, future development costs and commodity pricing differentials are the most significant of our estimates. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, recent commodity prices, operating costs and other factors. These revisions could materially affect our financial statements. The volatility of commodity prices results in increased uncertainty inherent in these estimates and assumptions. Changes in natural gas, oil or NGL prices could result in actual results differing significantly from our estimates. See Note 19 included in Item 8 of this report for further information.

Income Taxes. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized in the year in which realization becomes determinable. Quarterly, management performs a forecast of its taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established, if in management's opinion, it is more likely than not that some portion will not be realized. At December 31, 2020, a valuation allowance of $985.5 million had been established to fully offset our net deferred tax asset on our accompanying consolidated balance sheet.

Revenue Recognition. We derive almost all of our revenue from the sale of natural gas, crude oil and NGL produced from our oil and natural gas properties. Revenue is recorded in the month the product is delivered to the purchaser. We receive payment on substantially all of these sales from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers that month and the price we will receive. Variances between our estimated revenue and actual payment received for all prior months are recorded at the end of the quarter after payment is received. Historically, our actual payments received have not significantly deviated from our accruals.

Derivative Instruments. We seek to reduce our exposure to unfavorable changes in natural gas, oil and NGL prices, which are subject to significant and often volatile fluctuation, by entering into over-the-counter fixed price swaps, basis swaps, costless collars and various types of option contracts. All derivative instruments are recognized as assets or liabilities in the balance sheet, measured at fair value. We estimate the fair value of all derivative instruments using industry-standard models that considered various assumptions including current market and contractual prices for the underlying instruments, implied volatility, time value, nonperformance risk, as well as other relevant economic measures.

The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Our current commodity derivative instruments are not designated as hedges for accounting purposes. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities.

See Item 7A. "*Natural Gas, Oil and NGL Derivatives*" for a summary of our derivative instruments in place as of December 31, 2020.

Disclosures About Effects of Transactions with Related parties

Our equity method investees are considered related parties. See Notes 5, 10 and 16 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of transactions with our equity method investees.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk. Our results of operations and cash flows are impacted by changes in market prices for oil, natural gas and NGL, which have been historically volatile and are even more volatile as a result of COVID-19 and decisions of the Organization of Petroleum Exporting Countries and other high oil-exporting countries ("OPEC+") discussed in this Form 10-K. To mitigate a portion of our exposure to adverse price changes, we enter into various derivative instruments, we have entered into various derivative instruments. Our natural gas, oil and NGL derivative activities, when combined with our sales of natural gas, oil and NGL, allow us to predict with greater certainty the revenue we will receive. We believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

Our general strategy for protecting short-term cash flow and attempting to mitigate exposure to adverse natural gas, oil and NGL price changes is to hedge into strengthening natural gas, oil and NGL futures markets when prices reach levels that management believes are unsustainable for the long term, have material downside risk in the short term or provide reasonable rates of return on our invested capital. Information we consider in forming an opinion about future prices includes general economic conditions, industrial output levels and expectations, producer breakeven cost structures, liquefied natural gas trends, oil and natural gas storage inventory levels, industry decline rates for base production and weather trends. Executive management is involved in all risk management activities and the Board of Directors reviews our derivative program at its quarterly board meetings. We believe we have sufficient internal controls to prevent unauthorized trading.

We use derivative instruments to achieve our risk management objectives, including swaps and options. All of these are described in more detail below. We typically use swaps for a large portion of the oil and natural gas price risk we hedge. We have also sold calls, taking advantage of premiums associated with market price volatility.

We determine the notional volume potentially subject to derivative contracts by reviewing our overall estimated future production levels, which are derived from extensive examination of existing producing reserve estimates and estimates of likely production from new drilling. Production forecasts are updated at least monthly and adjusted if necessary to actual results and activity levels. We do not enter into derivative contracts for volumes in excess of our share of forecasted production, and if production estimates were lowered for future periods and derivative instruments are already executed for some volume above the new production forecasts, the positions would be reversed. The actual fixed price on our derivative instruments is derived from the reference NYMEX price, as reflected in current NYMEX trading. The pricing dates of our derivative contracts follow NYMEX futures. All of our commodity derivative instruments are net settled based on the difference between the fixed price as stated in the contract and the floating-price, resulting in a net amount due to or from the counterparty.

We review our derivative positions continuously and if future market conditions change and prices are at levels we believe could jeopardize the effectiveness of a position, we will mitigate this risk by either negotiating a cash settlement with our counterparty, restructuring the position or entering into a new trade that effectively reverses the current position. The factors we consider in closing or restructuring a position before the settlement date are identical to those we review when deciding to enter into the original derivative position. Gains or losses related to closed positions will be recognized in the month specified in the original contract.

We have determined the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to counterparty valuations for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. This non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. Future risk related to counterparties not being able to meet their obligations has been partially mitigated under our commodity hedging arrangements that require counterparties to post collateral if their obligations to us are in excess of defined thresholds. 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. See Note 13 of the notes to our consolidated financial statements included in Item 8 of this report for further discussion of the fair value measurements associated with our derivatives.

As of December 31, 2020, our natural gas derivative instruments consistent of the following types of instruments:

- *Swaps*: We receive a fixed price and pay a floating market price to the counterparty for the hedged commodity. In exchange for higher fixed prices on certain of our swap trades, we may sell call options.

- *Basis Swaps*: These instruments are arrangements that guarantee a fixed price differential to NYMEX from a specified delivery point. We receive the fixed price differential and pay the floating market price differential to the counterparty for the hedged commodity.

- *Options*: We sell, and occasionally buy, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, we pay the counterparty the excess on sold call options, and we receive the excess on bought call options. If the market price settles below the fixed price of the call option, no payment is due from either party.

- *Costless Collars*: Each two-way price collar has a set floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, the Company will cash-settle the difference with the counterparty.

Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or commodities prices increase. At December 31, 2020, we had a net liability derivative position of $20.8 million as compared to a net asset derivative position of $73.3 million as of December 31, 2019. Utilizing actual derivative contractual volumes, a 10% increase in underlying commodity prices would have reduced the fair value of these instruments by approximately $69.0 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by approximately $66.0 million. However, any realized derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

Interest Rate Risk. Our Pre-Petition Revolving Credit Facility and DIP Credit Facility are structured under floating rate terms, as advances under these facilities may be in the form of either base rate loans or eurodollar loans. As such, our interest expense is sensitive to fluctuations in the prime rates in the United States or, if the eurodollar rates are elected, the eurodollar rates. At December 31, 2020, we had $292.9 million in borrowings outstanding under our revolving credit facility which bore interest at the weighted average rate of 3.15%. At December 31, 2020, we had $157.5 million in borrowings under our DIP credit facility which bore interest at the weighted average rate of 5.50%A 1% increase in the average interest rate would have increased interest expense by approximately $2.1 million based on outstanding borrowings under our revolving credit facility and DIP credit facility at December 31, 2020. As of December 31, 2020, we did not have any interest rate swaps to hedge our interest risks.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Gulfport Energy Corporation

Opinion on the financial statements
We have audited the accompanying consolidated balance sheets of Gulfport Energy Corporation (a Delaware corporation) and subsidiaries (Debtor-in-Possession) (the “Company”) as of December 31, 2020 and 2019, the related consolidated statements of operations, comprehensive income (loss), stockholders’ (deficit) equity, and cash flows for each of the three years in the period ended December 31, 2020, and the related notes (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the Company’s internal control over financial reporting as of December 31, 2020, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”), and our report dated March 5, 2021 expressed an unqualified opinion.

Going Concern
The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the financial statements, the Company filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code during the year ended December 31, 2020, which constituted an event of default that accelerated the Company's obligations under the Company's pre-petition revolving credit facility and the indentures governing the Company's senior notes, resulting in the principal and interest due thereunder becoming immediately due and payable. These conditions, along with other matters as set forth in Note 1, raise substantial doubt about its ability to continue as a going concern. Management’s plans in regard to these matters are also described in Note 1. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Basis for opinion
These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical audit matters
The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Depletion expense and impairment of oil and gas properties impacted by the Company’s estimation of proved reserves

As described further in Note 1 to the financial statements, the Company uses the full cost method of accounting for oil and gas operations. This accounting method requires management to make estimates of proved reserves and related future net cash flows to compute and record depletion, depreciation and amortization, as well as to assess potential impairment of oil and gas properties (the full cost ceiling test). To estimate the volume of proved oil and gas reserve quantities, management makes significant estimates and assumptions including forecasting the production decline rate of producing properties and forecasting the timing and volume of production associated with the Company’s development plan for proved undeveloped properties. In addition, the estimation of proved reserves is also impacted by management’s judgments and estimates regarding the financial performance of wells associated with those proved reserves to determine if wells are expected to be economical under the appropriate pricing assumptions that are required in the estimation of depletion, depreciation and amortization expense and potential ceiling test impairment assessments. We identified the estimation of proved reserves as it relates to the recognition of depletion, depreciation and amortization expense and the assessment of potential impairment as a critical audit matter.

The principal consideration for our determination that the estimation of proved reserves is a critical audit matter is that relatively minor changes in certain inputs and assumptions that are necessary to estimate the volume and future cash flows of the Company's proved reserves could have a significant impact on the measurement of depletion, depreciation and amortization expense and/or impairment expense. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

Our audit procedures related to the estimation of proved reserves included the following, among others:

- We tested the design and operating effectiveness of internal controls relating to management's estimation of proved reserves for the purpose of estimating depletion, depreciation and amortization expense and assessing the Company's oil and gas properties for potential ceiling test impairment;
- We evaluated the independence, objectivity, and professional qualifications of the Company's reserves specialist, made inquiries of those reservoir engineers regarding the process followed and judgements made to estimate the Company's proved reserve volumes and read the report prepared by the Company's reserve specialist;
- We evaluated sensitive inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions that are derived from the Company's accounting records, such as historical pricing differentials, operating costs, estimated capital costs, and ownership interest. We tested management's process for determining the assumptions, including examining the underlying support, on a sample basis where applicable. Specifically, our audit procedures involved testing management's assumptions as follows:
    - Compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year and examined contractual support for pricing differentials, where applicable;
    - Tested the model used to estimate the operating costs at year end and compared to historical operating costs;
    - Tested the model used to determine the future capital expenditures and compared estimated future capital expenditures used in the reserve report to amounts expended for recently drilled and completed wells, where applicable;
    - Tested the working and net revenue interests used in the reserve report by inspecting land and division order records;
    - Evaluated the Company's evidence supporting the proved undeveloped properties reflected in the reserve report by examining historical conversion rates and support for the Company's ability to fund and intent to develop the proved undeveloped properties; and
    - Applied analytical procedures to the reserve report by comparing to historical actual results and to the prior year's reserve report.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2005.

Oklahoma City, Oklahoma
March 5, 2021

GULFPORT ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(DEBTOR-IN-POSSESSION)

	December 31, 2020	December 31, 2019
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 89,861	$ 6,060
Accounts receivable—oil and natural gas sales	119,879	121,210
Accounts receivable—joint interest and other	12,200	47,975
Prepaid expenses and other current assets	160,664	4,431
Short-term derivative instruments	27,146	126,201
Total current assets	409,750	305,877
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $1,457,043 and $1,686,666 excluded from amortization in 2020 and 2019, respectively	10,816,909	10,595,735
Other property and equipment	88,538	96,719
Accumulated depletion, depreciation, amortization and impairment	(8,819,178)	(7,228,660)
Property and equipment, net	2,086,269	3,463,794
Other assets:		
Equity investments	24,816	32,044
Long-term derivative instruments	322	563
Deferred tax asset	—	7,563
Operating lease assets	342	14,168
Operating lease assets - related parties	—	43,270
Other assets	18,372	15,540
Total other assets	43,852	113,148
Total assets	$ 2,539,871	$ 3,882,819
Liabilities and stockholders' (deficit) equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 244,903	$ 415,218
Short-term derivative instruments	11,641	303
Current portion of operating lease liabilities	—	13,826
Current portion of operating lease liabilities - related parties	—	21,220
Current maturities of long-term debt	253,743	631
Total current liabilities	510,287	451,198
Non-current liabilities:		
Long-term derivative instruments	36,604	53,135
Asset retirement obligation—long-term	—	60,355
Uncertain tax position liability	—	3,127
Non-current operating lease liabilities	—	342
Non-current operating lease liabilities - related parties	—	22,050
Long-term debt, net of current maturities	—	1,978,020
Total non-current liabilities	36,604	2,117,029
Liabilities subject to compromise	2,293,480	—
Total liabilities	2,840,371	2,568,227
Commitments and contingencies (Notes 17 and 18)		
Preferred stock, $0.01 par value; 5,000,000 authorized (30,000 authorized as redeemable 12% cumulative preferred stock, Series A), and none issued and outstanding	—	—
Stockholders' (deficit) equity:		
Common stock - $0.01 par value, 200,000,000 shares authorized, 160,762,186 issued and outstanding in 2020 and 159,710,955 in 2019	1,607	1,597
Paid-in capital	4,213,752	4,207,554
Accumulated other comprehensive loss	(43,000)	(46,833)
Accumulated deficit	(4,472,859)	(2,847,726)
Total stockholders' (deficit) equity	(300,500)	1,314,592
Total liabilities and stockholders' (deficit) equity	$ 2,539,871	$ 3,882,819

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(DEBTOR-IN-POSSESSION)

	For the Year Ended December 31,		
	2020	2019	2018
	(In thousands, except share data)		
REVENUES:			
Natural gas sales	$ 671,535	$ 1,135,381	$ 1,318,472
Oil and condensate sales	62,902	117,937	177,793
Natural gas liquid sales	66,814	101,448	178,915
Net gain (loss) on natural gas, oil, and NGL derivatives	65,291	208,360	(123,479)
Total Revenues	866,542	1,563,126	1,551,701
OPERATING EXPENSES:			
Lease operating expenses	54,235	73,496	79,716
Taxes other than income	28,509	40,510	48,298
Midstream gathering and processing expenses	456,318	508,843	486,845
Depreciation, depletion and amortization	239,744	550,108	486,664
Impairment of oil and natural gas properties	1,357,099	2,039,770	—
General and administrative expenses	59,329	45,542	47,100
Restructuring and liability management expenses	30,847	4,611	—
Accretion expense	3,066	3,939	4,119
Total Operating Expenses	2,229,147	3,266,819	1,152,742
(LOSS) INCOME FROM OPERATIONS	(1,362,605)	(1,703,693)	398,959
OTHER EXPENSE (INCOME):			
Interest expense	120,079	141,786	141,912
Interest income	(414)	(801)	(314)
Gain on debt extinguishment	(49,579)	(48,630)	—
Gain on sale of equity method investments	—	—	(124,768)
Loss (income) from equity method investments, net	11,055	210,148	(49,904)
Reorganization items, net	152,359	—	—
Other expense, net	21,738	3,725	1,542
Total Other Expense (Income)	255,238	306,228	(31,532)
(LOSS) INCOME BEFORE INCOME TAXES	(1,617,843)	(2,009,921)	430,491
INCOME TAX EXPENSE (BENEFIT)	7,290	(7,563)	(69)
NET (LOSS) INCOME	$ (1,625,133)	$ (2,002,358)	$ 430,560
NET (LOSS) INCOME PER COMMON SHARE:			
Basic	$ (10.14)	$ (12.49)	$ 2.46
Diluted	$ (10.14)	$ (12.49)	$ 2.45
Weighted average common shares outstanding—Basic	160,231,335	160,341,125	174,675,840
Weighted average common shares outstanding—Diluted	160,231,335	160,341,125	175,398,706

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME
(DEBTOR-IN-POSSESSION)

	For the Year Ended December 31,		
	2020	2019	2018
	(In thousands)		
Net (loss) income	$ (1,625,133)	$ (2,002,358)	$ 430,560
Foreign currency translation adjustment[1]	3,833	9,193	(15,487)
Other comprehensive income (loss)	3,833	9,193	(15,487)
Comprehensive (loss) income	$ (1,621,300)	$ (1,993,165)	$ 415,073

(1) No taxes were recorded for the years ended December 31, 2020, 2019 and 2018.

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' (DEFICIT) EQUITY
(DEBTOR-IN-POSSESSION)

	Common Stock		Paid-in Capital	Accumulated Other Comprehensive Loss	Accumulated Deficit	Total Stockholders' (Deficit) Equity
	Shares	Amount				
	(In thousands, except share data)					
Balance at January 1, 2018	183,105,910	$ 1,831	$ 4,416,250	$ (40,539)	$ (1,275,928)	$ 3,101,614
Net Income	—	—	—	—	430,560	430,560
Other Comprehensive Loss	—	—	—	(15,487)	—	(15,487)
Stock-based Compensation	—	—	11,332	—	—	11,332
Shares Repurchased	(20,746,536)	(207)	(200,044)	—	—	(200,251)
Issuance of Restricted Stock	626,671	6	(6)	—	—	—
Balance at December 31, 2018	162,986,045	$ 1,630	$ 4,227,532	$ (56,026)	$ (845,368)	$ 3,327,768
Net Loss	—	—	—	—	(2,002,358)	(2,002,358)
Other Comprehensive Income	—	—	—	9,193	—	9,193
Stock-based Compensation	—	—	10,677	—	—	10,677
Shares Repurchased	(3,951,198)	(40)	(30,648)	—	—	(30,688)
Issuance of Restricted Stock	676,108	7	(7)	—	—	—
Balance at December 31, 2019	159,710,955	$ 1,597	$ 4,207,554	$ (46,833)	$ (2,847,726)	$ 1,314,592
Net Loss	—	—	—	—	(1,625,133)	(1,625,133)
Other Comprehensive Income	—	—	—	3,833	—	3,833
Stock-based Compensation	—	—	6,444	—	—	6,444
Shares Repurchased	(243,054)	(3)	(233)	—	—	(236)
Issuance of Restricted Stock	1,294,285	13	(13)	—	—	—
Balance at December 31, 2020	160,762,186	$ 1,607	$ 4,213,752	$ (43,000)	$ (4,472,859)	$ (300,500)

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(DEBTOR-IN-POSSESSION)

	Year Ended December 31,		
	2020	2019	2018
	(In thousands)		
Cash flows from operating activities:			
Net (loss) income	$ (1,625,133)	$ (2,002,358)	$ 430,560
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depletion, depreciation and amortization	239,744	550,108	486,664
Impairment of oil and natural gas properties	1,357,099	2,039,770	—
Loss (income) from equity investments, net	11,055	210,289	(49,625)
Gain on debt extinguishment	(49,579)	(48,630)	—
Net loss (gain) on derivative instruments	(65,291)	(208,360)	123,479
Net cash receipts on settled derivative instruments	159,394	123,130	(58,428)
Non-cash reorganization items, net	21,956	—	—
Deferred income tax expense (benefit)	7,290	(7,563)	1,208
Gain on sale of equity method investments and other assets	—	(220)	(124,768)
Distributions from equity method investments	—	2,457	3,206
Other, net	31,984	15,178	17,039
Changes in operating assets and liabilities, net	6,785	50,192	(43,064)
Net cash provided by operating activities	95,304	723,993	786,271
Cash flows from investing activities:			
Additions to oil and natural gas properties	(367,287)	(720,057)	(899,083)
Proceeds from sale of oil and gas properties	50,971	48,527	5,114
Proceeds from sale of equity method investments	—	—	226,487
Other, net	1,729	(3,241)	(9,392)
Net cash used in investing activities	(314,587)	(674,771)	(676,874)
Cash flows from financing activities:			
Principal payments on pre-petition revolving credit facility	(383,290)	(877,000)	(220,000)
Borrowings on pre-petition revolving credit facility	713,701	952,000	265,000
Principal payments on DIP credit facility	(90,000)	—	—
Borrowings on DIP credit facility	90,000	—	—
Repurchase of senior notes	(22,827)	(138,786)	—
DIP credit facility financing fees	(2,988)	—	—
Payments on repurchase of stock under approved stock repurchase programs	—	(30,000)	(200,251)
Other, net	(1,512)	(1,673)	(1,406)
Net cash provided (used in) by financing activities	303,084	(95,459)	(156,657)
Net increase (decrease) in cash, cash equivalents and restricted cash	83,801	(46,237)	(47,260)
Cash, cash equivalents and restricted cash at beginning of period	6,060	52,297	99,557
Cash, cash equivalents and restricted cash at end of period	$ 89,861	$ 6,060	$ 52,297

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(DEBTOR-IN-POSSESSION)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business

Gulfport Energy Corporation, a Delaware corporation formed in 1997, is an independent natural gas-weighted exploration and production company focused on the production of natural gas, crude oil and NGL in the United States. The Company's principal properties are located in Eastern Ohio targeting the Utica formation and in central Oklahoma targeting the SCOOP Woodford and SCOOP Springer formations.

Voluntary Reorganization Under Chapter 11 of the Bankruptcy Code

On November 13, 2020, Gulfport Energy Corporation, Gator Marine, Inc., Gator Marine Ivanhoe, Inc., Grizzly Holdings, Inc., Gulfport Appalachia, LLC, Gulfport Midcon, LLC, Gulfport Midstream Holdings, LLC, Jaguar Resources LLC, Mule Sky LLC, Puma Resources, Inc. and Westhawk Minerals LLC filed voluntary petitions of relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the Southern District of Texas. The Chapter 11 Cases are being administered jointly under the caption *In re Gulfport Energy Corporation, et al.,* Case No. 20-35562 (DRJ). The debtors continue to operate their businesses as "debtors-in-possession" under the jurisdiction of the Bankruptcy Court, in accordance with the applicable provisions of the Bankruptcy Code and the orders of the Bankruptcy Court.

The commencement of a voluntary proceeding in bankruptcy constituted an event of default that accelerated the Company's obligations under the Company's Pre-Petition Revolving Credit Facility and the indentures governing the Company's senior notes, resulting in the principal and interest due thereunder becoming immediately due and payable. Subject to certain specific exceptions under the Bankruptcy Code, the filing of the Chapter 11 Cases automatically stayed all judicial or administrative actions against the Company and efforts by creditors to collect on or otherwise exercise rights or remedies with respect to pre-petition claims. Absent an order from the Bankruptcy Court, substantially all of the Debtors’ pre-petition liabilities are subject to settlement under the Bankruptcy Code.

The Company has applied FASB ASC Topic 852 -*Reorganizations* ("ASC 852") in preparing the consolidated financial statements, which specifies the accounting and financial reporting requirements for entities reorganizing through Chapter 11 bankruptcy proceedings. These requirements include distinguishing transactions associated with the reorganization separate from activities related to the ongoing operations of the business. Accordingly, pre-petition liabilities that may be impacted by the Chapter 11 proceedings have been classified as liabilities subject to compromise on the consolidated balance sheet as of December 31, 2020. Additionally, certain expenses, realized gains and losses and provisions for losses that are realized or incurred during the Chapter 11 Cases, including adjustments to the carrying value of certain indebtedness are recorded as reorganization items, net in the consolidated statements of operations for the year ended December 31, 2020. Refer to Note 2 for more information on the events of the bankruptcy proceedings as well as the accounting and reporting impacts of the reorganization.

Ability to Continue as a Going Concern

The accompanying consolidated financial statements are prepared in accordance with generally accepted accounting principles applicable to a going concern, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business.

As discussed above, the filing of the Chapter 11 Cases constituted an event of default under the Company’s Pre-Petition Revolving Credit Facility and the indentures governing the Company's senior notes (the "Default"), resulting in the principal and interest due thereunder becoming immediately due and payable. The Company does not have sufficient cash on hand or available liquidity to repay these amounts due. These conditions and events raise substantial doubt about the Company’s ability to continue as a going concern.

As part of the Chapter 11 Cases, the Company submitted the Plan to the Bankruptcy Court. The Company’s operations and its ability to develop and execute its business plan are subject to a high degree of risk and uncertainty associated with the Chapter 11 Cases. The outcome of the Chapter 11 Cases is subject to a high degree of uncertainty and is dependent upon factors that are outside of the Company’s control, including actions of the Bankruptcy Court and the Company’s creditors.

There can be no assurance that the Company will confirm and consummate the plan of reorganization as contemplated by the RSA with certain holders of the Company's senior notes or complete another plan of reorganization with respect to the Chapter 11 Cases. As a result, the Company has concluded that management's plans do not alleviate substantial doubt about the Company's ability to continue as a going concern.

While operating as a debtor-in-possession, the Company may settle liabilities, subject to the approval of the Bankruptcy Court or as otherwise permitted in the ordinary course of business, for amounts other than those reflected in the accompanying consolidated financial statements. Further, the Plan or other bankruptcy proceedings could materially change the amounts and classifications of assets and liabilities reported in the consolidated financial statements, including liabilities subject to compromise which will be resolved in connection with the Chapter 11 Cases. The accompanying consolidated financial statements do not include any adjustments related to the recoverability and classification of assets or the amounts and classification of liabilities or any other adjustments that might be necessary should the Company be unable to continue as a going concern or as a consequence of the Chapter 11 Cases.

Risks and Uncertainties

In March 2020, the World Health Organization classified the outbreak of COVID-19 as a pandemic and recommended containment and mitigation measures worldwide. The measures have led to worldwide shutdowns and halting of commercial and interpersonal activity, as governments around the world have imposed regulations in efforts to control the spread of COVID-19 such as shelter-in-place orders, quarantines, executive orders and similar restrictions.

Gulfport remains focused on protecting the health and well-being of its employees and the communities in which it operates while assuring the continuity of its business operations. The Company implemented preventative measures and developed corporate and field response plans to minimize unnecessary risk of exposure and prevent infection. Additionally, the Company has a crisis management team for health, safety and environmental matters and personnel issues, and has established a COVID-19 Response Team to address various impacts of the situation, as they have been developing. Gulfport has modified certain business practices (including remote working for its corporate employees and restricted employee business travel) to conform to government restrictions and best practices encouraged by the Centers for Disease Control and Prevention, the World Health Organization and other governmental and regulatory authorities. In May 2020, the Company began its phased transition back to the office for its corporate employees. As part of this transition, the Company put into place preventative measures to focus on social distancing and minimizing unnecessary risk of exposure. As of the date of this filing, Gulfport has transitioned the vast majority of its employees back to the corporate office; however, the Company continues to provide a balanced work schedule that allows for a significant portion of the work week to be performed remotely. The Company will continue to monitor trends and governmental guidelines and may adjust its return to office plans accordingly to ensure the health and safety of its employees. As a result of its business continuity measures, the Company has not experienced significant disruptions in executing its business operations in 2020.

On March 27, 2020, the U.S. government enacted the Coronavirus Aid, Relief, and Economic Security Act ("CARES Act"). The CARES Act did not have a material impact on the Company's consolidated financial statements. Gulfport is closely monitoring the impact of COVID-19 on all aspects of its business and the current commodity price environment and is unable to predict the impact it will have on its future financial position or operating results.

Decreased demand for oil and natural gas as a result of the COVID-19 pandemic has put further downward pressure on commodity pricing. In the current depressed commodity price environment and period of economic uncertainty, the Company has taken the following operational and financial measures in 2020 to improve its balance sheet and preserve liquidity:

- Reduced 2020 capital spending by more than 50% as compared to 2019
- Focused on operational efficiencies to reduce operating costs; including significant improvements in development and completion costs per lateral foot
- Repurchased $73.3 million of unsecured notes at a discount
- Evaluated economics across our portfolio and shut-in certain non-economical production in the second quarter of 2020
- Reduced recurring corporate general and administrative costs significantly through pay reductions, furloughs and reductions in force.

Although management's actions listed above have helped to improve the Company's liquidity and leverage profile, continued macro headwinds including the depressed state of energy capital markets and the extraordinarily low commodity price environments resulted in the Company filing for protection under Bankruptcy Rules as noted above.

Principles of Consolidation

The consolidated financial statements include the Company and its wholly-owned subsidiaries, Grizzly Holdings Inc., Jaguar Resources LLC, Gator Marine, Inc., Gator Marine Ivanhoe, Inc., Westhawk Minerals LLC, Puma Resources, Inc., Gulfport Appalachia LLC, Gulfport Midstream Holdings, LLC, Gulfport MidCon, LLC and Mule Sky LLC. All intercompany balances and transactions are eliminated in consolidation.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents for purposes of the consolidated financial statements.

Accounts Receivable

The Company sells oil and natural gas to various purchasers and participates in drilling, completion and operation of oil and natural gas wells with joint interest owners on properties the Company operates. The related receivables are classified as accounts receivable—oil and natural gas sales and accounts receivable—joint interest and other, respectively. Credit is extended based on evaluation of a customer's payment history and, generally, collateral is not required. Accounts receivable are due within 30 days and are stated at amounts due from customers, net of an allowance for doubtful accounts when the Company believes collection is doubtful. Accounts outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the customer's current ability to pay its obligation to the Company, amounts which may be obtained by an offset against production proceeds due the customer and the condition of the general economy and the industry as a whole. No material allowance was deemed necessary at December 31, 2020 and December 31, 2019.

Oil and Gas Properties

The Company uses the full cost method of accounting for oil and gas operations. Accordingly, all costs, including nonproductive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and gas properties, are capitalized. Additionally, interest is capitalized on the cost of unproved oil and natural gas properties that are excluded from amortization for which exploration and development activities are in process or expected within the next 12 months.

Under the full cost method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions or financial derivatives, if any, that hedge the Company's oil and natural gas revenue (only to the extent that the derivative instruments are treated as cash flow hedges for accounting purposes), and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of unproved properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. Ceiling test impairment can result in a significant loss for a particular period; however, future depletion expense would be reduced. A decline in oil and gas prices may result in an impairment of oil and gas properties. As a result of the decline in commodity prices throughout 2020, the Company recognized ceiling test impairments of $1.4 billion for the year ended December 31, 2020.

Such capitalized costs, including the estimated future development costs and site remediation costs of proved undeveloped properties, are depleted by an equivalent units-of-production method, converting barrels to gas at the ratio of one barrel of oil to six Mcf of gas. No gain or loss is recognized upon the disposal of oil and gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proved oil and gas reserves. Oil and gas properties not subject to amortization consist of the cost of unproved leaseholds and totaled approximately $1.5 billion and $1.7 billion at December 31, 2020 and December 31, 2019, respectively. These costs are reviewed quarterly by management for impairment. If impairment has occurred, the portion of cost in excess of the current value is transferred to the cost of oil and gas properties subject to amortization. Factors considered by management in its impairment assessment include drilling results by Gulfport and other operators, the terms of oil and gas leases not held by production, and available funds for exploration and development.

The Company accounts for its abandonment and restoration liabilities by recording a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, the Company increases the carrying amount of oil and natural gas properties by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is included in capitalized costs and depreciated consistent with depletion of reserves. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

Other Property and Equipment

Depreciation of other property and equipment is provided on a straight-line basis over the estimated useful lives of the related assets, which range from3 to 30 years.

Foreign Currency

The U.S. dollar is the functional currency for Gulfport's consolidated operations. However, the Company has an equity investment in a Canadian entity whose functional currency is the Canadian dollar. The assets and liabilities of the Canadian investment are translated into U.S. dollars based on the current exchange rate in effect at the balance sheet dates. Canadian income and expenses are translated at average rates for the periods presented and equity contributions are translated at the current exchange rate in effect at the date of the contribution. In addition, the Company has an equity investment in a U.S. company that has a subsidiary that is a Canadian entity whose functional currency is the Canadian dollar. Translation adjustments have no effect on net income and are included in accumulated other comprehensive income in stockholders' (deficit) equity. The following table presents the balances of the Company's cumulative translation adjustments included in accumulated other comprehensive loss, exclusive of taxes.

	(In thousands)
December 31, 2017	(39,190)
December 31, 2018	(54,677)
December 31, 2019	(45,484)
December 31, 2020	(41,651)

Net (Loss) Income per Common Share

Basic net (loss) income per common share is computed by dividing income attributable to common stock by the weighted average number of common shares outstanding for the period. Diluted net (loss) income per common share reflects the potential dilution that could occur if options or other contracts to issue common stock were exercised or converted into common stock. Potential common shares are not included if their effect would be anti-dilutive. Calculations of basic and diluted net (loss) income per common share are illustrated in Note 12.

Income Taxes

Gulfport uses the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized as income in the year in which realization becomes determinable. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

The Company is subject to U.S. federal income tax as well as income tax of multiple jurisdictions. The Company's 2003 – 2019 U.S. federal and 2009 - 2019 state income tax returns remain open to examination by tax authorities, due to net operating losses. As of December 31, 2020, the Company has no unrecognized tax benefits that would have a material impact on the effective rate. The Company recognizes interest and penalties related to income tax matters as interest expense and general and administrative expenses, respectively.

Revenue Recognition

The Company's revenues are primarily derived from the sale of natural gas, oil and condensate and NGL. Sales of natural gas, oil and condensate and NGL are recognized in the period that the performance obligations are satisfied. The Company generally considers the delivery of each unit (MMBtu or Bbl) to be separately identifiable and represents a distinct performance obligation that is satisfied at a point-in-time once control of the product has been transferred to the customer. The Company considers a variety of facts and circumstances in assessing the point of control transfer, including but not limited to (i) whether the purchaser can direct the use of the product, (ii) the transfer of significant risks, (iii) the Company's right to payment and (iv) transfer of legal title.

Gathering, processing and compression fees attributable to gas processing, as well as any transportation fees, including firm transportation fees, incurred to deliver the product to the purchaser, are presented as midstream, gathering and processing expense in the accompanying consolidated statements of operations.

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

The recognition of gains or losses on derivative instruments is outside the scope of ASC 606,*Revenue from Contracts with Customers* and is not considered revenue from contracts with customers subject to ASC 606. The Company may use financial or physical contracts accounted for as derivatives as economic hedges to manage price risk associated with normal sales, or in limited cases may use them for contracts the Company intends to physically settle but do not meet all of the criteria to be treated as normal sales.

The Company has elected to exclude from the measurement of the transaction price all taxes assessed by governmental authorities that are both imposed on and concurrent with a specific revenue-producing transaction and collected by the Company from a customer, such as sales tax, use tax, value-added tax and similar taxes.

See Note 9 for additional discussion of revenue from contracts with customers.

Investments—Equity Method

Investments in entities in which the Company owns an equity interest greater than 20% and less than 50% and/or investments in which it has significant influence are accounted for under the equity method. Under the equity method, the Company's share of investees' earnings or loss is recognized in the consolidated statements of operations.

The Company reviews its investments annually to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, the Company recognizes an impairment provision. The Company did not record any impairment charges related to its investments in Mammoth and Grizzly for the year ended December 31, 2020. During the year ended December 31, 2019, the Company recorded impairments of $160.8 million related to its investment in Mammoth Energy and $32.4 million related to its investment in Grizzly. There were no impairment charges recorded for the year ended December 31, 2018.See Note 5 for further discussion of Mammoth Energy and Grizzly impairments.

Accounting for Stock-based Compensation

Share-based payments to employees, including grants of restricted stock, are recognized as equity or liabilities at the fair value on the date of grant and to be expensed over the applicable vesting period. The vesting periods for restricted shares range between one to three years with annual vesting installments. The Company does not recognize expense based on an estimate of forfeitures, but rather recognizes the impact of forfeitures only as they occur. The Company will continue to account for its share-based payments consistent with prior periods until the Bankruptcy Court takes specific actions to modify or cancel existing awards.

Derivative Instruments

The Company utilizes commodity derivatives to manage the price risk associated with forecasted sale of its natural gas, crude oil and NGL production. All derivative instruments are recognized as assets or liabilities in the consolidated balance sheets, measured at fair value. The Company does not apply hedge accounting to derivative instruments. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements and revenues and expenses during the reporting period. Actual results could differ materially from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and gas reserve quantities and the related present value of estimated future net cash flows there from, the amount and timing of asset retirement obligations, the realization of deferred tax assets, the fair value determination of acquired assets and liabilities and the realization of future net operating loss carryforwards available as reductions of income tax expense. The estimate of the Company’s oil and gas reserves is used to compute depletion, depreciation, amortization and impairment of oil and gas properties.

Supplemental cash flow and non-cash information

	Year Ended December 31,		
	2020	2019	2018
Supplemental disclosure of cash flow information:		(In thousands)	
Cash paid for reorganization items, net	$ 24,553	$ —	$ —
Interest payments	$ 84,823	$ 142,664	$ 132,995
Income tax receipts	$ —	$ (1,794)	$ —
Supplemental disclosure of non-cash transactions:			
Capitalized stock-based compensation	$ 2,860	$ 5,766	$ 4,533
Asset retirement obligation capitalized	$ 2,358	$ 6,883	$ 1,452
Asset retirement obligation removed due to divestiture	$ (2,213)	$ (30,146)	$ —
Interest capitalized	$ 907	$ 3,372	$ 4,470
Pre-petition revolver principal transfer to DIP credit facility	$ 157,500	$ —	$ —
Fair value of contingent consideration asset on date of divestiture	$ 23,090	$ (1,137)	$ —
Foreign currency translation gain (loss) on equity method investments	$ 3,833	$ 9,193	$ (15,487)

Reclassifications

In the fourth quarter of 2020, the Company updated the presentation of certain costs on its consolidated statements of operations to better align its cost reporting with industry peers. In particular, the Company created a new expense line item titled “Taxes other than income” in its consolidated statement of operations. This new line item includes production taxes, property taxes and certain other non-income tax related costs incurred. Prior period amounts have been reclassified to align to this new approach. The reclassifications have no impact on previously reported total assets, liabilities, net (loss) income or total operating cash flows.

Impact on Previously Reported Results

During the third quarter of 2020, the Company identified that certain transportation activities during the years ended December 31, 2019 and 2018 were misclassified between "natural gas sales" and "midstream gathering and processing expenses" on its consolidated statements of operations. The Company assessed the materiality of this presentation on prior periods’ consolidated financial statements in accordance with the SEC Staff Accounting Bulletin No. 99, “Materiality”, codified in Accounting Standards Codification Topic 250, “Accounting Changes and Error Corrections". Based on this assessment, the Company concluded that the correction is not material to any previously issued financial statements. The correction had no impact on its consolidated balance sheets, consolidated statements of comprehensive income, consolidated statements of stockholders' equity or consolidated statements of cash flows. Additionally, the error had no impact on net loss or net loss per share. The Company will conform presentation of previously reported consolidated statements of operations in future filings.

The following tables present the effect of the correction on all affected line items of our previously issued consolidated financial statements of operations for the years ended December 31, 2019 and 2018.

	Year Ended December 31, 2019		
	As Reported	Adjustments	As Revised
		(In thousands)	
Natural gas sales	$ 918,263	$ 217,118	$ 1,135,381
Total Revenues	$ 1,346,008	$ 217,118	$ 1,563,126
Midstream gathering and processing expenses	$ 291,725	$ 217,118	$ 508,843
Total Operating Expenses	$ 3,049,701	$ 217,118	$ 3,266,819

	Year Ended December 31, 2018		
	As Reported	Adjustments	As Revised
		(In thousands)	
Natural gas sales	$ 1,121,815	$ 196,657	$ 1,318,472
Total Revenues	$ 1,355,044	$ 196,657	$ 1,551,701
Midstream gathering and processing expenses	$ 290,188	$ 196,657	$ 486,845
Total Operating Expenses	$ 956,085	$ 196,657	$ 1,152,742

Recent Adopted Accounting Pronouncements

On January 1, 2020, the Company adopted ASU No. 2016-13, *Financial Instruments-Credit Losses: Measurement of Credit Losses on Financial Instruments*, which replaces the incurred loss impairment methodology with a methodology that reflects expected credit losses and requires consideration of a broader range of reasonable and supportable information to inform credit loss estimates. The measurement of expected credit losses is based on relevant information about past events, including historical experience, current conditions and reasonable and supportable forecasts that affect the collectability of the reported amount. The Company adopted the new standard using the prospective transition method, and it did not have a material impact on the Company's consolidated financial statements and related disclosures.

2. CHAPTER 11 PROCEEDINGS

Restructuring Support Agreement

On November 13, 2020, the Debtors commenced the Chapter 11 Cases as described in Note 1 above. To ensure ordinary course operations, the Debtors have obtained approval from the Bankruptcy Court for certain "first day" motions, including motions to obtain customary relief intended to continue ordinary course operations after the Petition Date. In addition, the Debtors have received authority to use cash collateral of the lenders under the DIP Credit Facility.

On November 13, 2020, the Debtors entered into a restructuring support agreement with (i) over 95% of the lenders (the "Consenting RBL Lenders") party to the Pre-Petition Revolving Credit Facility, dated as of December 27, 2013, by and among the Company, as borrower, each of the lenders party thereto, the Bank of Nova Scotia, as administrative agent and issuing bank, the joint lead arrangers and joint bookrunners, the co-syndication agents, and the co-documentation agents and (ii) certain holders (the "Consenting Noteholders," and, together with the Consenting RBL Lenders, the "Consenting Stakeholders") holding over two-thirds of the Company's (a) 6.625% senior notes due 2023, issued under that certain Indenture, dated as of April 21, 2015, (b) 6.000% senior notes due 2024, issued under that certain Indenture, dated as of October 14, 2016, (c) 6.375% senior notes due 2025, issued under that certain Indenture, dated as of December 21, 2016, and (d) 6.375% senior notes due 2026, issued under that certain Indenture, dated as of October 11, 2017 (collectively, the "Unsecured Notes"), each by and among the Company, the subsidiary guarantors party thereto, and UMB Bank, N.A. as successor trustee.

The RSA outlines the key elements and actions the Company plans to take as part of Chapter 11 process, including equitizing a significant portion of its prepetition indebtedness and rejecting or renegotiating certain contracts which will result in a materially improved balance sheet and cost structure. The RSA contains certain covenants on the part of each of Gulfport and the Consenting Stakeholders, including commitments by the Consenting Stakeholders to vote in favor of the Plan and commitments of Gulfport and the Consenting Stakeholders to negotiate in good faith to finalize the documents and agreements governing the Restructuring. The RSA also places certain conditions on the obligations of the parties and provides that the RSA may be terminated upon the occurrence of certain events, including, without limitation, the failure to achieve certain milestones and certain breaches by the parties under the RSA. One such condition is the requirement to obtain sufficient savings on certain midstream obligations (as set forth in the RSA) through rejection of such contracts and/or renegotiation of their terms.

Although Gulfport intends to pursue the Restructuring in accordance with the terms set forth in the RSA, there can be no assurance that Gulfport will be successful in completing a restructuring or any other similar transaction on the terms set forth in the RSA, on different terms, or at all.

Plan of Reorganization

The Restructuring contemplated under the RSA will be pursued by Gulfport pursuant to a prearranged joint plan of reorganization (the “Plan”). Capitalized terms used under this heading titled “Joint Prearranged Chapter 11 Plan of Reorganization” but not otherwise defined herein shall have the meaning given to such terms in the Plan. The Plan can be found as an exhibit to this Form 10-K.

Below is a summary of the treatment that the stakeholders of the Company would receive under the Plan:

- each Holder of an Allowed Other Secured Claim shall receive, at the option of the applicable Debtor and with the consent of the Required Consenting Stakeholders (such consent not to be unreasonably withheld): (a) payment in full in Cash of its Allowed Other Secured Claim; (b) the collateral securing its Allowed Other Secured Claim; (c) Reinstatement of its Allowed Other Secured Claim; or (d) such other treatment rendering its Allowed Other Secured Claim unimpaired in accordance with section 1124 of the Bankruptcy Code;
- each Holder of an Allowed Other Priority Claim shall receive treatment in a manner consistent with section 1129(a)(9) of the Bankruptcy Code;
- each Holder of an Allowed RBL Claim shall receive, at the option of each such Holder, either (a) its Pro Rata share of the Exit RBL/Term Loan A Facility, if such Holder elects to participate in the Exit RBL/Term Loan A Facility or (b) its Pro Rata share of the Exit Term Loan B Facility, if such Holder does not elect to participate in the Exit RBL/Term Loan A Facility (including by not making any election with respect to the Exit Facility on the ballot);
- each Holder of an Allowed General Unsecured Claim against Gulfport Parent shall receive in full and final satisfaction of such Claim, its Pro Rata share of the Gulfport Parent Equity Pool; provided, however, that once the Holders of Notes Claims receive distributions of 94% of the New Common Stock (prior to and not including any dilution by the Management Incentive Plan or any conversion of New Preferred Stock into New Common Stock) in the aggregate on account of their Notes Claims against all Debtors, the Holders of Notes Claims shall waive any excess recovery on account of their Pro Rata share of the Gulfport Parent Equity Pool until Holders of Allowed General Unsecured Claims against Gulfport Parent have received New Common Stock with a value sufficient to satisfy their Allowed General Unsecured Claims against Gulfport Parent in full (based on Plan Value);
- each Holder of an Allowed General Unsecured Claim against Gulfport Subsidiaries shall receive in full and final satisfaction of such Claim, its Pro Rata share of: (a) the Gulfport Subsidiaries Equity Pool; (b) the Rights Offering Subscription Rights; and (c) the New Unsecured Notes;
- each Holder of an Allowed Notes Claim against Gulfport Parent shall receive, in full and final satisfaction of such Claim, its Pro Rata share of the Gulfport Parent Equity Pool; provided, however, that once the Holders of Notes Claims receive distributions of 94% of the New Common Stock (prior to and not including any dilution by the Management Incentive Plan or any conversion of New Preferred Stock into New Common Stock) in the aggregate on account of their Notes Claims against all Debtors, the Holders of Notes Claims shall waive any excess recovery on account of their Pro Rata share of the Gulfport Parent Equity Pool until Holders of Allowed General Unsecured Claims against Gulfport Parent have received New Common Stock with a value sufficient to satisfy their Allowed General Unsecured Claims against Gulfport Parent in full (based on Plan Value); provided further, however, distributions to any Holder of a Notes Claim against Gulfport Parent shall be subject to the rights and terms of the Notes Indentures and the rights of the Notes Trustee to assert the Notes Trustee Charging Lien;
- each Holder of an Allowed Notes Claim against Gulfport Subsidiaries shall receive, in full and final satisfaction of such Claim, its Pro Rata share of the: (i) Gulfport Subsidiaries Equity Pool, (ii) Rights Offering Subscription Rights, and (iii) New Unsecured Notes; provided, however, distributions to any Holder of a Notes Claim against Gulfport

Subsidiaries shall be subject to the rights and terms of the Notes Indentures and the rights of the Notes Trustee to assert the Notes Trustee Charging Lien;

- each Intercompany Claim shall be cancelled in exchange for the distributions contemplated by the Plan to Holders of Claims against and Interests in the respective Debtor entities and shall be considered settled pursuant to Bankruptcy Rule 9019;
- each Holder of an Intercompany Interest shall receive no recovery or distribution and shall be Reinstated solely to the extent necessary to maintain the Debtors' prepetition corporate structure for the ultimate benefit of the Holders of New Common Stock and New Preferred Stock; and
- all Existing Interests (i.e. equity) in Gulfport Parent and all Allowed Section 510(b) Claims, if any, shall be cancelled, released, extinguished, and of no further force or effect.

DIP Credit Facility

Pursuant to the RSA, the Consenting RBL Lenders have agreed to provide the Company with a senior secured superpriority debtor-in-possession revolving credit facility in an aggregate principal amount of $262.5 million consisting of (a) $105 million of new money and (b) $157.5 million to roll up a portion of the existing outstanding obligations under the Pre-Petition Revolving Credit Facility. The proceeds of the DIP Credit Facility may be used for, among other things, post-petition working capital, permitted capital investments, general corporate purposes, letters of credit, administrative costs, premiums, expenses and fees for the transactions contemplated by the Chapter 11 Cases and payment of court approved adequate protection obligations. In the current period, the Company incurred $3.0 million of fees related to the arrangement and funding of the DIP Credit Facility. The DIP Credit Facility was approved by the Bankruptcy Court on a final basis on December 18, 2020. See Note 6 for additional information.

Executory Contracts

Subject to certain exceptions, under the Bankruptcy Code, the Company may assume, assign, or reject certain executory contracts and unexpired leases subject to the approval of the Bankruptcy Court and certain other conditions. Generally, the rejection of an executory contract or unexpired lease is treated as a pre-petition breach of such executory contract or unexpired lease and, subject to certain exceptions, relieves the Company from performing its future obligations under such executory contract or unexpired lease but entitles the contract counterparty or lessor to a pre-petition general unsecured claim for damages caused by such deemed breach. Counterparties to rejected contracts or leases may assert unsecured claims in the Bankruptcy Court against the Company's estate for such damages. Generally, the assumption of an executory contract or unexpired lease requires the Company to cure existing monetary defaults under such executory contract or unexpired lease and provide adequate assurance of future performance. Accordingly, any description of an executory contract or unexpired lease with the Company, including where applicable a quantification of the Company's obligations under any such executory contract or unexpired lease of the Company, is qualified by any overriding rejection rights it has under the Bankruptcy Code.

Potential Claims

The Company has filed with the Bankruptcy Court schedules and statements setting forth, among other things, the assets and liabilities of the Company and each of its subsidiaries, subject to the assumptions filed in connection therewith. These schedules and statements may be subject to further amendment or modification after filing. Certain holders of pre-petition claims that are not governmental units were required to file proofs of claim by the deadline for general claims, which was set by the Bankruptcy Court as January 26, 2021. Governmental units are required to file proof of claims by May 12, 2021, the deadline that was set by the Bankruptcy Court.

As of February 25, 2021, the Debtors have received approximately2,200 proofs of claim for an aggregate amount of approximately $12.5 billion. The Company will continue to evaluate these claims throughout the Chapter 11 process and recognize or adjust amounts in future financial statements as necessary using the best information available at such time. Differences between amounts scheduled by the Company and claims by creditors will ultimately be reconciled and resolved in connection with the claims resolution process. In light of the expected number of creditors, the claims resolution process may take considerable time to complete and likely will continue after the Company emerges from bankruptcy.

Financial Statement Classification of Liabilities Subject to Compromise

The accompanying audited consolidated balance sheet as of December 31, 2020, includes amounts classified as liabilities subject to compromise, which represent liabilities the Company anticipates will be allowed as claims in the Chapter 11 Cases.

These amounts represent the Company's current estimate of known or potential obligations to be resolved in connection with the Chapter 11 Cases, and may differ from actual future settlement amounts paid. Differences between liabilities estimated and claims filed, or to be filed, will be investigated and resolved in connection with the claims resolution process. The Company will continue to evaluate these liabilities throughout the Chapter 11 process and adjust amounts as necessary. Such adjustments may be material.

Liabilities subject to compromise includes amounts related to the rejection of various executory contracts. Additional amounts may be included in liabilities subject to compromise in future periods if additional executory contracts and/or unexpired leases are rejected. The nature of many of the potential claims arising under the Company's executory contracts and unexpired leases has not been determined at this time, and therefore, such claims are not reasonably estimable at this time and may be material. Damages related to rejected contracts are accounted for after they have been approved for rejection by the Bankruptcy Court.

The following table summarizes the components of liabilities subject to compromise included on the Company's audited consolidated balance sheet as of December 31, 2020:

	December 31, 2020 (in thousands)
Debt subject to compromise	$ 2,005,219
Accounts payable and accrued liabilities	164,939
Asset retirement obligations	63,566
Accrued interest on debt subject to compromise	55,634
Other liabilities	4,122
Liabilities subject to compromise	$ 2,293,480

Interest Expense

The Company has discontinued recording interest on debt instruments classified as liabilities subject to compromise as of the Petition Date. The contractual interest expense on liabilities subject to compromise not accrued in the consolidated statements of operations was approximately $15.3 million from the Petition Date through December 31, 2020.

Reorganization Items, Net

The Company has incurred and will continue to incur significant expenses, gains and losses associated with the reorganization, primarily the write-off of unamortized debt issuance costs, debt and equity financing fees, adjustments to allowed claims and legal and professional fees incurred subsequent to the Chapter 11 filings for the restructuring process. The amount of these items, which are being incurred in reorganization items, net within the Company's accompanying audited consolidated statements of operations, are expected to significantly affect the Company's statements of operations. The Company has incurred adjustments for allowable claims related to its legal proceedings and executory contracts approved for rejections by the Bankruptcy Court, with additional adjustments possible in future periods.

The following table summarizes the components in reorganization items, net included in the Company's audited consolidated statements of operations for the year ended December 31, 2020:

	Year Ended December 31, 2020 (in thousands)
Adjustment to allowed claims	$ 104,943
Legal and professional fees	24,905
Write off of unamortized issuance costs on debt subject to compromise	21,956
DIP credit facility financing fees	2,988
Gain on settlement of pre-petition accounts payable	(2,433)
Reorganization items, net	$ 152,359

3. DIVESTITURES

Sale of Water Infrastructure Assets

On January 2, 2020, the Company closed on the sale of its SCOOP water infrastructure assets to a third-party water service provider. The Company received $50.0 million in cash proceeds upon closing and has an opportunity to earn potential additional incentive payments over the next 15 years, subject to the Company's ability to meet certain thresholds which will be driven by, among other things, the Company's future development program and water production levels. The agreement contained no minimum volume commitments. The fair value of the contingent consideration as of the closing date was $23.1 million. See Note 15 for additional discussion of the fair value of the contingent consideration.

The divested assets were included in the amortization base of the full cost pool and no gain or loss was recognized in the accompanying consolidated statements of operations as a result of the sale.

Sale of Non-operated Utica Interests

In December 2019, the Company entered into an agreement to divest certain non-operated interests in the Utica for approximately $29.0 million in cash subject to customary closing terms and adjustments. This sale closed on December 30, 2019.

Sale of Bakken Overriding Royalty Interests

During 2019, the Company announced the sale of certain overriding royalty interests associated with assets the Company held in the Bakken. The sale closed on December 11, 2019 and, net of purchase price adjustments, the Company received approximately $7.0 million of total proceeds.

Sale of Southern Louisiana Assets

In December 2018, the Company entered into an agreement to sell its non-core assets located in the West Cote Blanche Bay and Hackberry fields of southern Louisiana to an undisclosed third party for a purchase price of approximately $19.7 million. The sale closed on July 3, 2019, subject to customary post-closing terms and conditions, with an effective date of August 15, 2018. The Company received approximately $9.2 million in cash and retained contingent overriding royalty interests. In addition, the Company could also receive contingent payments based on commodity prices exceeding specified thresholds over the two years following the closing date. See Note 13 for further discussion of the contingent consideration arrangement, which was determined to be an embedded derivative. The buyer assumed all plugging and abandonment liabilities associated with these assets which totaled approximately $30.0 million at the divestiture date.

4. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of December 31, 2020 and 2019 are as follows:

	December 31, 2020	December 31, 2019
	(In thousands)	
Oil and natural gas properties	$ 10,816,909	$ 10,595,735
Other depreciable property and equipment	85,530	91,198
Land	3,008	5,521
Total property and equipment	10,905,447	10,692,454
Accumulated depletion, depreciation, amortization and impairment	(8,819,178)	(7,228,660)
Property and equipment, net	$ 2,086,269	$ 3,463,794

Under the full cost method of accounting, capitalized costs of oil and natural gas properties are subject to a quarterly full cost ceiling test, which is discussed in Note 1. During the years ended December 31, 2020 and 2019, the Company incurred $1.4 billion and $2.0 billion of impairments, respectively, as a result of its oil and natural gas properties exceeding its calculated ceiling. The lower ceiling values resulted primarily from significant decreases in the 12-month average trailing prices for natural gas, oil and NGL, which significantly reduced proved reserves values and proved reserves. No impairment of oil and natural gas properties was required under the ceiling test for the year ended December 31, 2018.

General and administrative costs capitalized to the full cost pool represent management’s estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All general and administrative costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized general and administrative costs were approximately $25.0 million, $30.1 million and $37.7 million for the years ended December 31, 2020, 2019 and 2018, respectively. The average depletion rate per Mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $0.61, $1.08 and $0.96 per Mcfe for the years ended December 31, 2020, 2019 and 2018, respectively.

The following is a summary of Gulfport’s oil and natural gas properties not subject to amortization as of December 31, 2020:

	Costs Incurred in				
	2020	2019	2018	Prior to 2018	Total
	(In thousands)				
Acquisition costs	$ 18,485	$ 8,067	$ 98,876	$ 1,330,895	$ 1,456,323
Exploration costs	—	—	—	—	—
Development costs	—	—	—	—	—
Capitalized interest	—	121	172	427	720
Total oil and natural gas properties not subject to amortization	$ 18,485	$ 8,188	$ 99,048	$ 1,331,322	$ 1,457,043

The following table summarizes the Company’s non-producing properties excluded from amortization by area as of December 31, 2020:

	December 31, 2020
	(In thousands)
Utica	$ 793,441
SCOOP	662,614
Other	988
	$ 1,457,043

As of December 31, 2019, approximately $1.7 billion of non-producing property costs were subject to amortization.

The Company evaluates the costs excluded from its amortization calculation at least annually. Subject to industry conditions and the level of the Company’s activities, the inclusion of most of the above referenced costs into the Company’s amortization calculation typically occurs within three to five years. However, the majority of the Company's non-producing leases in the Utica have five-year extension terms which could extend this time frame beyond five years.

A reconciliation of the Company's asset retirement obligation for the years ended December 31, 2020 and 2019 is as follows:

	December 31, 2020	December 31, 2019
	(In thousands)	
Asset retirement obligation, beginning of period	$ 60,355	$ 79,952
Liabilities incurred	2,358	5,935
Liabilities settled	—	(273)
Liabilities removed due to divestitures	(2,213)	(30,146)
Accretion expense	3,066	3,939
Revisions in estimated cash flows	—	948
Total asset retirement obligation as of end of period	63,566	60,355
Less: amounts reclassified to liabilities subject to compromise	(63,566)	—
Total asset retirement obligation reflected as non-current liabilities	$ —	$ 60,355

5. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of December 31, 2020 and 2019:

	Approximate Ownership %	Carrying Value December 31, 2020	Carrying Value December 31, 2019	Loss (income) from equity method investments For the Year Ended December 31, 2020	2019	2018
				(In thousands)		
Investment in Grizzly Oil Sands ULC	24.5 %	$ 24,816	$ 21,000	$ 377	$ 32,710	$ 510
Investment in Mammoth Energy Services, Inc.	21.5 %	—	11,005	10,646	179,524	(49,969)
Investment in Tatex Thailand II, LLC	23.5 %	—	—	—	(2,086)	(241)
Other equity investments[(1)]	— %	—	39	32	—	(204)
		$ 24,816	$ 32,044	$ 11,055	$ 210,148	$ (49,904)

(1) Consists of sold/dissolved investments, including Windsor Midstream, LLC, which was dissolved as of December 31, 2020. Additionally, this includes the Company's investment in Strike Force that was sold in 2018, from which the Company recognized a gain of $96.4 million net of transaction fees, which is included in gain on sale of equity method investments in the accompanying consolidated statement of operations for the year ended December 31, 2018.

The tables below summarize financial information for the Company's equity investments, as of December 31, 2020 and 2019.

Summarized balance sheet information:

	December 31, 2020	December 31, 2019
	(In thousands)	
Current assets	$ 483,303	$ 421,326
Noncurrent assets	$ 1,092,495	$ 1,260,075
Current liabilities	$ 132,978	$ 132,569
Noncurrent liabilities	$ 148,240	$ 163,241

Summarized results of operations:

	December 31,		
	2020	2019	2018
	(In thousands)		
Gross revenue	$ 313,076	$ 625,012	$ 1,729,778
Net (loss) income	$ (106,072)	$ (76,523)	$ 253,451

Grizzly Oil Sands ULC

The Company, through its wholly owned subsidiary Grizzly Holdings, owns a24.5% interest in Grizzly, a Canadian unlimited liability company. The remaining interest in Grizzly is owned by Grizzly Oil Sands Inc. As of December 31, 2020, Grizzly had approximately 830,000 acres under lease in the Athabasca, Peace River and Cold Lake oil sands regions of Alberta, Canada.

The Company reviewed its investment in Grizzly at December 31, 2020 and December 31, 2019 for impairment based on certain qualitative and quantitative factors. This resulted in recording no impairment losses and $32.4 million for the years ended December 31, 2020 and 2019, respectively, which is included in loss from equity method investments, net in the accompanying consolidated statements of operations. The Company reviewed its investment in Grizzly for impairment at December 31, 2018 and determined no impairment was required.

The Company did not pay any cash calls during 2020 as a result of its election to cease funding further capital calls in 2019. The Company paid $0.4 million in cash calls during the year ended December 31, 2019 prior to this election. Grizzly's functional currency is the Canadian dollar. The Company's investment in Grizzly was increased by a $4.2 million foreign currency translation gain, increased by a $9.0 million foreign currency translation gain and decreased by a $15.2 million foreign currency translation loss for the years ended December 31, 2020, 2019 and 2018, respectively. The Company had $40.6 million and $44.8 million in accumulated other comprehensive loss in its accompanying consolidated balance sheets related to Grizzly at December 31, 2020 and December 31, 2019, respectively, that will be included in the calculations of future charge related to a sale or abandonment.

Mammoth Energy Services, Inc.

On June 29, 2018, the Company sold 1,235,600 shares of its Mammoth Energy common stock in an underwritten public offering for net proceeds of approximately $47.0 million. In connection with the Company's public offering of a portion of its shares of Mammoth Energy common stock, the Company granted the underwriters an option to purchase additional shares of its Mammoth Energy common stock. On July 26, 2018, the underwriters exercised this option, in part, and on July 30, 2018, the Company sold an additional 118,974 shares for net proceeds of approximately $4.5 million. Following the sales of these shares, the Company owned 9,829,548 shares, or 21.5% at December 31, 2018, of Mammoth Energy's outstanding common stock. As a result of the sales, the Company recorded a gain of $28.3 million, which is included in gain on sale of equity method investments in the accompanying consolidated statements of operations. The approximate fair value of the Company's investment in Mammoth Energy's common stock at December 31, 2019 was $21.6 million based on the quoted market price of Mammoth Energy's common stock.

At December 31, 2020, the Company owned 9,829,548 shares, or 21.5%, of the outstanding common stock of Mammoth Energy. As a result of the net loss Mammoth sustained in the first quarter of 2020, we recorded a loss of $10.6 million for the year ended December 31, 2020 which reduced the Company's investment balance in Mammoth to zero. This is included in loss (income) from equity method investments, net in the accompanying consolidated statements of operations. The Company's investment in Mammoth Energy was increased by a $0.2 million foreign currency gain and decreased by a $0.4 million foreign currency loss resulting from Mammoth Energy's foreign subsidiary for the years ended December 31, 2019 and 2018, respectively. During the year ended December 31, 2019, Gulfport received distributions of $2.5 million from Mammoth Energy as a result of dividends in February 2019 and May 2019. The approximate fair value of the Company's investment in Mammoth Energy's common stock at December 31, 2020 was $43.7 million based on the quoted market price of Mammoth Energy's common stock. The loss (income) from equity method investments presented in the table above reflects any intercompany profit eliminations.

Tatex Thailand II, LLC

The Company has an indirect ownership interest in Tatex Thailand II, LLC ("Tatex") and receivedno distributions from Tatex during the year ended December 31, 2020. The Company received $2.1 million in distributions from Tatex during the year ended December 31, 2019. Tatex previously held an 8.5% interest in an entity holding a reserve base in Southeast Asia, including the Phu Horm Field, before selling its interest in June 2019.

6. LONG-TERM DEBT

Long-term debt consisted of the following items as of December 31:

	2020	2019
	(In thousands)	
DIP credit facility	$ 157,500	$ —
Pre-petition revolving credit facility	292,910	120,000
6.625% senior unsecured notes due 2023	324,583	329,467
6.000% senior unsecured notes due 2024	579,568	603,428
6.375% senior unsecured notes due 2025	507,870	529,525
6.375% senior unsecured notes due 2026	374,617	397,529
Building loan	21,914	22,453
Net unamortized debt issuance costs	—	(23,751)
Total Debt, net	2,258,962	1,978,651
Less: current maturities of long term debt	(253,743)	(631)
Less: amounts reclassified to liabilities subject to compromise	(2,005,219)	—
Total Debt reflected as long term	$ —	$ 1,978,020

Chapter 11 Proceedings

Filing of the Chapter 11 Cases constituted an event of default with respect to certain of our secured and unsecured debt obligations. As a result of the Chapter 11 Cases, the principal and interest due under these debt instruments became immediately due and payable. However, Section 362 of the Bankruptcy Code stays the creditors from taking any action as a result of the default.

The principal amounts from the Senior Notes, Building Loan and Pre-Petition Revolving Credit Facility, other than letters of credit drawn on the Pre-Petition Revolving Credit Facility after the Petition Date, have been classified as liabilities subject to compromise on the accompanying audited consolidated balance sheet as of December 31, 2020. Additionally, non-cash adjustments were made to write off all of the related unamortized debt issuance costs of $22.0 million, which are included in reorganization items, net in the accompanying audited consolidated statements of operations for the year ended December 31, 2020, as discussed in Note 2.

Debtor-in-Possession Credit Agreement

Pursuant to the RSA, the Consenting RBL Lenders have agreed to provide the Company with a senior secured superpriority debtor-in-possession revolving credit facility in an aggregate principal amount of $262.5 million consisting of (a) $105 million of new money and (b) $157.5 million to roll up a portion of the existing outstanding obligations under the Pre-Petition Revolving Credit Facility. The terms and conditions of the DIP Credit Facility are set forth in that certain form of credit agreement governing the DIP Credit Facility. The proceeds of the DIP Credit Facility may be used for, among other things, post-petition working capital, permitted capital investments, general corporate purposes, letters of credit, administrative costs, premiums, expenses and fees for the transactions contemplated by the Chapter 11 Cases and payment of court approved adequate protection obligations. In the current period, the Company incurred $3.0 million of fees related to the arrangement and funding of the DIP Credit Facility. The DIP Credit Facility was approved by the Bankruptcy Court on a final basis on December 18, 2020.

Borrowings under the DIP Credit Facility will mature, and the lending commitments thereunder will terminate, upon the earliest to occur of: (a) August 30, 2021; (b) three (3) business days after the Petition Date, if the Interim Order and Hedging

Order have not been entered prior to the expiration of such period; (c) thirty five (35) days (or a later date consented to by the Administrative Agent and the Majority Lenders in their sole discretion) after the entry of the Interim Order, if the Bankruptcy Court has not entered the Final Order on or prior to such date; (d) the effective date of an Approved Plan of Reorganization, (e) the consummation of a sale of all or substantially all of the equity and/or assets of the Debtors and budgeted and necessary expenses of the estates; (f) the date of the payment in full, in cash, of all Obligations (and the termination of all Commitments in accordance with the terms hereof); and (g) the date of termination of all Commitments and/or the acceleration of all of the Obligations under the Agreement and the other Loan Documents following the occurrence and during the continuance of an Event of Default.

Borrowings under the DIP Credit Facility bear interest at a eurodollar rate or base rate, at our election, plus an applicable margin of 4.50% per annum for eurodollar loans and 3.50% per annum for base rate loans. At December 31, 2020, amounts borrowed under the DIP credit facility bore interest at a weighted average rate of 5.50%. In addition to paying interest on outstanding principal and letters of credit posted under the DIP Credit Facility, we are required to pay a commitment fee of 0.50% per annum to the lenders of the DIP Credit Facility in respect of the unutilized DIP commitments thereunder and a letter of credit fee equal to 0.20% per annum.

The DIP Credit Facility includes negative covenants that, subject to significant exceptions, limit the Company's ability and the ability of its restricted subsidiaries to, among other things, (i) create liens on assets, property revenues, (ii) make investments, (iii) incur additional indebtedness, (iv) engage in mergers, consolidations, liquidations and dissolutions, (v) sell assets, (vi) pay dividends and distributions or repurchase capital stock, (vii) cease for any reason to be the operator of its properties, (viii) enter into letters of credit without prior written consent, (ix) enter into certain commodity hedging contracts except commodity hedging contracts with terms approved by the Bankruptcy Court in the hedging order or certain interest rate contracts, (x) change lines of business, (xi) engage in certain transactions with affiliates and (xii) incur more than a certain amount in capital expenditures in any calendar month. The DIP Credit Facility includes certain customary representations and warranties, affirmative covenants and events of default, including but not limited to defaults on account of nonpayment, breaches of representations and warranties and covenants, certain bankruptcy-related events, certain events under ERISA, material judgments and a change in control. If an event of default occurs, the lenders under the DIP Credit Facility will be entitled to take various actions, including the acceleration of all amounts due under the DIP Credit Facility and all actions permitted to be taken under the loan documents or application of law. In addition, the DIP Credit Facility is subject to various other financial performance covenants, including compliance with certain financial metrics and adherence to a budget approved by the Company's DIP Credit Facility lenders.

Pre-Petition Revolving Credit Facility

The Company has entered into a senior secured revolving credit facility agreement, as amended, with The Bank of Nova Scotia, as the lead arranger and administrative agent and certain lenders from time to time party thereto. On May 1, 2020, the Company entered into the fifteenth amendment to the Amended and Restated Credit Agreement. As part of the amendment, the Company's borrowing base and elected commitment were reduced from $1.2 billion and $1.0 billion, respectively, to $700.0 million. Additionally, the amendment added a requirement to maintain a ratio of Net Secured Debt to EBITDAX (as defined under the revolving credit agreement) not exceeding 2.00 to 1.00, deferred the requirement to maintain a ratio of Net Funded Debt to EBITDAX of 4.00 to 1.00 until September 30, 2021, and added a limitation on the repurchase of unsecured notes, among other amendments.

On July 27, 2020, the Company entered into the sixteenth amendment to the Amended and Restated Credit Agreement. Among other changes, the Sixteenth Amendment amends the Credit Agreement to: (i) require that, in the event of any issuances of Senior Notes, including Second Lien Notes, after the effective date, the then effective borrowing base will be reduced by a variable amount prescribed in the Credit Agreement to the extent the proceeds are not used to satisfy previously issued senior notes within 90 days of such issuance; (ii) require that each Loan Notice specify the amount of the then effective Borrowing Base and Pro Forma Borrowing Base, the Aggregate Elected Commitment Amount, and the current Total Outstandings, both with and without regard to the requested Borrowing; (iii) permit the Borrower or any Restricted Subsidiary to enter into obligations in connection with a Permitted Bond Hedge Transaction or Permitted Warrant Transaction; (iv) permit the Borrower to make any payments of Senior Notes and Subordinated Obligation prior to their scheduled maturity, in any event not to exceed $750 million or, if lesser, the net cash proceeds of any Senior Notes issued within 90 days before such payment; (v) require that the Senior Notes have a stated maturity date of no earlier than March 13, 2024, as well as not require payment of principal prior to such date, in order for the Borrower to be permitted to secure indebtedness under the Senior Notes; (vi) permit certain additional liens securing obligations in respect of the incurrence or issuance of any Permitted Refinancing Notes (as such term is defined in the Credit Agreement) not to exceed $750 million, subject to the terms of an intercreditor agreement; and (vii) amend and restate the Applicable Rate Grid.

On October 8, 2020, the Company's borrowing base under its Pre-Petition Revolving Credit Facility was reduced for the second time in 2020 from $700 million to $580 million, thereby significantly reducing the Company's available liquidity. On October 15, 2020, the Company elected to not pay interest on certain Senior Notes outstanding triggering a default under the credit agreement. There was $292.9 million of outstanding borrowings under the Pre-Petition Revolving Credit Facility as of December 31, 2020 that were not rolled up into the DIP Credit Facility. This amount of indebtedness will remain outstanding throughout the Chapter 11 Cases and will continue to accrue interest at the default interest rate on amounts drawn after the Petition Date. The Company made certain adequate protection payments of $1.3 million on its Pre-Petition Revolving Credit Facility between the Petition Date and December 31, 2020 which reduced the amount of outstanding borrowings under the Pre-Petition Revolving Credit Facility classified as liabilities subject to compromise as of December 31, 2020 in the accompanying consolidated balance sheets.

Additionally, as of December 31, 2020, we had an aggregate of $147.5 million of letters of credit outstanding under our Pre-Petition Revolving Credit Facility. This facility is secured by substantially all of our assets. All of our wholly-owned subsidiaries, excluding Grizzly Holdings and Mule Sky, guarantee our obligations under our revolving credit facility.

During the fourth quarter of 2020, $171.8 million was drawn on letters of credit secured by the Company's Pre-Petition Revolving Credit Facility by its firm transportation providers. Of these drawn letters of credit, $96.2 million were drawn after the Petition Date. As these were post-petition activities, the post-petition letters of credit drawn are included in current portion of long-term debt, in the accompanying consolidated balance sheets. The pre-petition amounts are included in borrowings outstanding as of December 31, 2020 which are included in liabilities subject to compromise in the accompanying consolidated balance sheets. At December 31, 2020 the Company included $111.8 million in prepaid and other current assets in the accompanying consolidated balance sheets as an offset for the drawn letters of credit. A portion of the drawn letters of credit were netted against pre-petition accounts payable to the Company's firm transportation providers and another portion was charged to reorganization items, net in the accompanying consolidated statements of operations.

As of December 31, 2020, amounts borrowed under the Pre-Petition Revolving Credit Facility bore interest at the weighted average rate of 3.15%.

Senior Unsecured Notes

Loan issuance costs related to the Senior Notes have been presented as a reduction to the principal amount of the Senior Notes at December 31, 2019. At December 31, 2020, there were no remaining unamortized loan issuance costs related to the Senior Notes. The Company expensed approximately $22.0 million in unamortized loan issuance costs related to the Senior Notes to reorganization items, net as a result of the Chapter 11 filing and the application of ASC 852.

Building Loan

In June 2015, the Company entered into a loan for the construction of its corporate headquarters in Oklahoma City, which was substantially completed in December 2016. Interest accrues daily on the outstanding principal balance at a fixed rate of 4.50% per annum. The building loan matures on June 4, 2025. As of December 31, 2020, the total borrowings under the building loan were approximately $21.9 million, which has been classified as liabilities subject to compromise in the accompanying consolidated balance sheets as of December 31, 2020.

Debt Repurchases

In July of 2019, the Company's Board of Directors authorized $100 million of cash to be used to repurchase its Senior Notes in the open market at discounted values to par. In December 2019, the Company's Board of Directors increased the authorized size of its senior note repurchase program to $200 million in total. During the year ended December 31, 2020, the Company used borrowings under its revolving credit facility to repurchase in the open market approximately $73.3 million aggregate principal amount of its outstanding Notes for $22.8 million in cash and recognized a $49.6 million gain on debt extinguishment, which included retirement of unamortized issuance costs and fees associated with the repurchased debt. This gain is included in gain on debt extinguishment in the accompanying consolidated statements of operations.

Interest Expense

The following schedule shows the components of interest expense for the year ended December 31:

	2020	2019	2018
		(In thousands)	
Cash paid for interest	$ 84,823	$ 142,664	$ 132,995
Change in accrued interest	30,600	(3,834)	7,266
Capitalized interest	(907)	(3,372)	(4,470)
Amortization of loan costs	5,563	6,328	6,121
Total interest expense	$ 120,079	$ 141,786	$ 141,912

The Company capitalized approximately $0.9 million and $3.4 million in interest expense to undeveloped oil and natural gas properties during the years ended December 31, 2020 and 2019, respectively.

Fair Value of Debt

At December 31, 2020, the carrying value of the outstanding debt represented by the Notes was approximately $1.8 billion. Based on the quoted market prices (Level 1), the fair value of the Notes was determined to be approximately $1.2 billion at December 31, 2020.

7. CHANGES IN CAPITALIZATION

Stock Repurchases

In January 2018, the board of directors of the Company approved a stock repurchase program to acquire up to $100 million of the Company's outstanding stock during 2018. In May 2018, the Company's board of directors authorized the expansion of its stock repurchase program, authorizing the Company to acquire up to an additional $100 million of its outstanding common stock during 2018 for a total of up to $200 million. This repurchase program was authorized to extend through December 31, 2018 and the Company repurchased 20.7 million shares of common stock in 2018 for $200.0 million in aggregate consideration.

In January 2019, the board of directors of the Company approved a new stock repurchase program to acquire a portion of the Company's outstanding common stock within a 24-month period. During 2019, the Company repurchased 3.8 million shares for a cost of approximately $30 million under this board approved program. The program was suspended in the fourth quarter of 2019, and no further repurchases were made under this program.

For the years ended December 31, 2020 and 2019, the Company repurchased approximately 0.2 million and 0.1 million shares for approximately $0.2 million and $0.7 million, respectively, to satisfy tax withholding requirements incurred upon the vesting of restricted stock. All repurchased shares have been canceled and returned to the status of authorized but unissued shares.

8. STOCK-BASED COMPENSATION

The Company adopted the 2005 Plan in January 2005. The 2005 Plan was amended and restated in April 2013 with the 2013 Plan. During 2019, the Company further amended and restated the 2013 Plan with the 2019 Plan. The 2019 Plan provides for grants of options, stock appreciation rights, restricted awards (restricted stock and restricted stock units) and performance awards to employees, consultants and directors of the Company that, in aggregate, do not exceed 12,500,000 shares. The 2019 Plan is administered by the Compensation Committee of the Company's board of directors (the "Committee"). Among other responsibilities, the Committee selects individuals to receive awards and establishes the terms of awards. As of December 31, 2020, the Company has awarded an aggregate of 7,630,554 restricted stock units and 840,595 performance vesting restricted stock units under the 2019 Plan.

During the years ended December 31, 2020, 2019 and 2018 the Company's stock-based compensation cost was $16.3 million, $10.7 million and $11.3 million, respectively, of which the Company capitalized $2.9 million, $5.8 million and $4.5 million, respectively, relating to its exploration and development efforts. Stock compensation costs, net of the amounts capitalized, are included in general and administrative expenses in the accompanying consolidated statements of operations.

The following table summarizes restricted stock unit and performance vesting restricted stock unit activity for the twelve months ended December 31, 2020, 2019 and 2018:

	Number of Unvested Restricted Stock Units	Weighted Average Grant Date Fair Value	Number of Unvested Performance Vesting Restricted Stock Units	Weighted Average Grant Date Fair Value
Unvested shares as of January 1, 2018	976,027	$ 18.71	—	$ —
Granted	1,579,911	9.90	—	—
Vested	(626,671)	18.05	—	—
Forfeited	(393,456)	12.23	—	—
Unvested shares as of December 31, 2018	1,535,811	$ 11.57	—	$ —
Granted	4,011,073	$ 3.74	2,009,144	2.85
Vested	(676,108)	12.89	—	—
Forfeited	(772,458)	6.05	(225,484)	1.98
Unvested shares as of December 31, 2019	4,098,318	$ 4.73	1,783,660	$ 2.96
Granted	3,069,521	0.85	—	—
Vested	(1,294,285)	5.73	—	—
Forfeited	(4,171,041)	1.68	(943,065)	1.98
Unvested shares as of December 31, 2020	1,702,513	$ 4.74	840,595	$ 4.07

Restricted Stock Units

Restricted stock units awarded under the 2019 Plan generally vest over a period ofone year in the case of directors andthree years in the case of employees and vesting is dependent upon the recipient meeting applicable service requirements. Stock-based compensation costs are recorded ratably over the service period. The grant date fair value of restricted stock units represents the closing market price of the Company's common stock on the date of grant. Unrecognized compensation expense as of December 31, 2020 related to outstanding restricted stock units was $5.2 million. The expense is expected to be recognized over a weighted average period of 1.31 years.

Performance Vesting Restricted Stock Units

During the year ended December 31, 2019, the Company awarded performance vesting restricted stock units to certain of its executive officers under the 2019 Plan. The number of shares of common stock issued pursuant to the award will be based on Relative Total Shareholder Return ("RTSR"). RTSR is an incentive measure whereby participants will earn from 0% to 200% of the target award based on the Company's RTSR ranking compared to the RTSR of the companies in the Company's designated peer group at the end of the performance period. Awards will be earned and vested over a performance period measured from January 1, 2019 to December 31, 2021, subject to earlier termination of the performance period in the event of a change in control. The grant date fair value was determined using the Monte Carlo simulation method and is being recorded ratably over the performance period. Expected volatilities utilized in the Monte Carlo model were estimated using a historical period consistent with the remaining performance period of approximately two years. The risk-free interest rates were based on the U.S. Treasury rate for a term commensurate with the expected life of the grant. The Company assumed a range of risk-free interest rates of 1.56% to 2.42% and a range of expected volatilities of 29.1% to 85.1% to estimate the fair value of performance vesting units granted during the year ended December 31, 2020. Unrecognized compensation expense as of December 31, 2020 related to performance vesting restricted stock units was $1.4 million. The expense is expected to be recognized over a weighted average period of 1.27 years.

Cash Incentive Awards

On March 16, 2020, the Board of Directors of the Company approved the Company's 2020 Incentive Plan (the "2020 Incentive Plan"). The 2020 Incentive Plan provided for incentive compensation opportunities ("Incentive Awards") for select employees of the Company that were tied to the achievement of one or more performance goals relating to certain financial and operational metrics over a period of time. During March 2020, the Company awarded Incentive Awards to certain of its executive officers under the 2020 Incentive Plan. The cash amount of each award to be ultimately received was based on the attainment of certain financial, operational and total shareholder return performance targets and was subject to the recipient's continuous employment. The Incentive Awards were considered liability awards as the ultimate amount of the award was based, at least in part, on the price of the Company's shares, and as such, were remeasured to fair value at the end of each reporting period. In August 2020 all previous unpaid amounts related to the Incentive Awards issued under the 2020 Incentive Plan were canceled and replaced with cash retention incentives, as discussed below.

2020 Compensation Adjustments

On August 4, 2020, the Company's Board of Directors authorized a redesign of the incentive compensation program for the Company's workforce, including for its current named executive officers. In connection with a comprehensive review of the Company's compensation programs and in consultation with its independent compensation consultant and legal advisors, the Board of Directors determined that significant changes were appropriate to retain and motivate the Company's employees as a result of the ongoing uncertainty and unprecedented disruption in the oil and gas industry.

All unpaid amounts previously awarded pursuant to the 2020 Incentive Plan and all restricted stock units granted in March 2020 to the Company's named executive officers were cancelled and replaced with cash retention incentives. These cash retention incentives are equally weighted between achievement of certain specified performance metrics and a service period. Of the cash retention incentives, 50% may be clawed back on an after-tax basis if an executive officer terminates employment for any reason other than a qualifying termination prior to the earlier of July 31, 2021, a change in control or completion of a restructuring, and the remaining 50% will be subject to repayment on an after-tax basis if established performance metrics are not met over performance periods from August 1, 2020 through July 31, 2021. In total, $13.5 million in cash retention incentives were paid to the Company's executives in August 2020.

The transactions were considered a modification to the previously issued equity- and liability-classified awards, and the previously issued equity-classified awards were reclassified as liability awards. The after-tax value of the cash incentives paid to the Company's executives of $3.6 million as of December 31, 2020 was capitalized to prepaid expenses and other current assets in the accompanying consolidated balance sheets and will be amortized over the remaining service period. The Company immediately expensed the difference between the cash and after-tax value of the prepaid cash incentives of $4.8 million, which is not subject to the clawback provisions, and recognized an additional $1.5 million in stock compensation expense to adjust for the difference in cash retention amounts paid and expense previously recognized on the modified awards at the modification date.

9. REVENUE FROM CONTRACTS WITH CUSTOMERS

Revenue Recognition

The Company's revenues are primarily derived from the sale of natural gas, oil and condensate and NGL. Sales of natural gas, oil and condensate and NGL are recognized in the period that the performance obligations are satisfied. The Company generally considers the delivery of each unit (MMBtu or Bbl) to be separately identifiable and represents a distinct performance obligation that is satisfied at the time control of the product is transferred to the customer. Revenue is measured based on consideration specified in the contract with the customer, and excludes any amounts collected on behalf of third parties. These contracts typically include variable consideration that is based on pricing tied to market indices and volumes delivered in the current month. As such, this market pricing may be constrained (i.e., not estimable) at the inception of the contract but will be recognized based on the applicable market pricing, which will be known upon transfer of the goods to the customer. The payment date is usually within 30 days of the end of the calendar month in which the commodity is delivered.

Transaction Price Allocated to Remaining Performance Obligations

A significant number of the Company's product sales are short-term in nature generally through evergreen contracts with contract terms of one year or less. These contracts typically automatically renew under the same provisions. For those contracts, the Company has utilized the practical expedient allowed in the new revenue accounting standard that exempts the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For product sales that have a contract term greater than one year, the Company has utilized the practical expedient that exempts the Company from disclosure of the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required. Currently, the Company's product sales that have a contractual term greater than one year have no long-term fixed consideration.

Contract Balances

Receivables from contracts with customers are recorded when the right to consideration becomes unconditional, generally when control of the product has been transferred to the customer. Receivables from contracts with customers were $119.9 million and $121.2 million as of December 31, 2020 and December 31, 2019, respectively, and are reported in accounts receivable - oil and natural gas sales in the accompanying consolidated balance sheets. The Company currently has no assets or liabilities related to its revenue contracts, including no upfront or rights to deficiency payments.

Prior-Period Performance Obligations

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for certain sales may be received for 30 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production that was delivered to the purchaser and the price that will be received for the sale of the product. The differences between the estimates and the actual amounts for product sales is recorded in the month that payment is received from the purchaser. For the year ended December 31, 2020, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

10. LEASES

Nature of Leases

The Company has operating leases on certain equipment and field offices with remaining lease durations in excess of one year. The Company recognizes a right-of-use asset and lease liability on the balance sheet for all leases with lease terms of greater than one year. Short-term leases that have an initial term of one year or less are not capitalized.

The Company has entered into contracts for drilling rigs with varying terms with third parties to ensure operational continuity, cost control and rig availability in its operations. The Company has concluded its drilling rig contracts are operating leases as the assets are identifiable and the Company has the right to control the identified assets. The Company's drilling rig commitments are typically structured with an initial term of less than one year to two years, although at December 31, 2020, the Company did not have any active long-term drilling rig contracts in place. These agreements typically include renewal options at the end of the initial term. Due to the nature of the Company's drilling schedules and potential volatility in commodity prices, the Company is unable to determine at contract commencement with reasonable certainty if the renewal options will be exercised; therefore, renewal options are not considered in the lease term for drilling contracts. The operating lease liabilities associated with these rig commitments, when applicable, are based on the minimum contractual obligations, primarily standby rates, and do not include variable amounts based on actual activity in a given period. Pursuant to the full cost method of accounting, these costs are capitalized as part of oil and natural gas properties on the accompanying consolidated balance sheets. A portion of drilling costs are borne by other interest owners in our wells.

Effective October 1, 2014, the Company entered into an Amended and Restated Master Services Agreement for pressure pumping services with Stingray, a subsidiary of Mammoth Energy and a related party. Pursuant to this agreement, as amended effective July 1, 2018, Stingray has agreed to provide hydraulic fracturing, stimulation and related completion and rework services to the Company through 2021 and the Company has agreed to pay Stingray a monthly service fee plus the associated costs of the services provided. As discussed further in Note 18, the Company terminated the Master Services Agreement for pressure pumping with Stingray. As a result, in the first quarter of 2020, Gulfport removed the related right of use assets and lease liabilities associated with the terminated contract.

The Company rents office space for its field locations and certain other equipment from third parties, which expire at various dates through 2024. These agreements are typically structured with non-cancelable terms of one to five years. The Company has determined these agreements represent operating leases with a lease term that equals the primary non-cancelable contract term. The Company has included any renewal options that it has determined are reasonably certain of exercise in the determination of the lease terms.

As of December 31, 2020, all lease liabilities have been classified as liabilities subject to compromise in the accompanying consolidated balance sheet.

Discount Rate

As most of the Company's leases do not provide an implicit rate, the Company uses its incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. The Company's incremental borrowing rate reflects the estimated rate of interest that it would pay to borrow on a collateralized basis over a similar term an amount equal to the lease payments in a similar economic environment.

Future amounts due under operating lease liabilities as of December 31, 2020 were as follows:

	(In thousands)
2021	$ 129
2022	115
2023	90
2024	30
Total lease payments	364
Less: Imputed interest	(22)
Less: amounts reclassified to liabilities subject to compromise	(342)
Total lease liabilities	$ —

Lease costs incurred for the years ended December 31, 2020 and 2019 consisted of the following:

	For the Year Ended December 31,	
	2020	2019
	(In thousands)	
Operating lease cost	$ 9,658	$ 24,960
Operating lease cost - related party	—	22,440
Variable lease cost	586	2,172
Variable lease cost - related party	—	66,924
Short-term lease cost	9,361	834
Total lease cost(1)	$ 19,605	$ 117,330

(1) The majority of the Company's total lease cost was capitalized to the full cost pool, and the remainder was included in general and administrative expenses in the accompanying consolidated statements of operations.

Supplemental cash flow information for the years ended December 31, 2020 and 2019 related to leases was as follows:

	For the Year Ended December 31,	
	2020	2019
Cash paid for amounts included in the measurement of lease liabilities	(In thousands)	
Operating cash flows from operating leases	140	182
Investing cash flow from operating leases	10,272	24,263
Investing cash flow from operating leases - related party	6,800	84,750

The weighted-average remaining lease term as of December 31, 2020 was3.03 years. The weighted-average discount rate used to determine the operating lease liability as of December 31, 2020 was 4.22%.

11. INCOME TAXES

The income tax provision consists of the following:

	2020	2019	2018
		(In thousands)	
Current:			
State	$ —	$ —	$ (1,530)
Federal	(273)	(7)	253
Deferred:			
State	7,563	(7,556)	1,530
Federal	—	—	(322)
Total income tax expense (benefit) provision	$ 7,290	$ (7,563)	$ (69)

A reconciliation of the statutory federal income tax amount to the recorded expense follows:

	2020	2019	2018
		(In thousands)	
(Loss) income before federal income taxes	$ (1,617,843)	$ (2,009,921)	$ 430,491
Expected income tax at statutory rate	(339,747)	(422,083)	90,403
State income taxes	(14,696)	(28,316)	(511)
Other differences	10,800	3,372	1,078
Change in valuation allowance due to current year activity	350,933	439,464	(91,039)
Income tax expense (benefit) recorded	$ 7,290	$ (7,563)	$ (69)

The tax effects of temporary differences and net operating loss carryforwards, which give rise to deferred tax assets and liabilities at December 31, 2020, 2019 and 2018 are estimated as follows:

	2020	2019	2018
		(In thousands)	
Deferred tax assets:			
Net operating loss carryforward	$ 392,318	$ 269,851	$ 164,363
Oil and gas property basis difference	463,705	289,850	3,595
Investment in pass through entities	61,078	58,951	8,620
Stock-based compensation expense	1,223	1,440	616
Business energy investment tax credit	370	370	369
Charitable contributions carryover	318	297	269
Change in fair value of derivative instruments	7,656	11,219	2,761
Foreign tax credit carryforwards	523	943	2,009
Accrued liabilities	868	669	834
ARO liability	13,414	12,744	16,923
Non-oil and gas property basis difference	—	—	104
Lease liability	72	12,128	—
Reorganization items	25,714	—	—
State net operating loss carryover	22,191	13,258	11,526
Interest expense carryforward	—	23,818	—
Total deferred tax assets	989,450	695,538	211,989
Valuation allowance for deferred tax assets	(985,528)	(647,575)	(211,987)
Deferred tax assets, net of valuation allowance	3,922	47,963	2
Deferred tax liabilities:			
Non-oil and gas property basis difference	575	1,859	—
Change in fair value of derivative instruments	3,272	26,410	2
Right of use asset	72	12,128	—
Other	3	3	—
Total deferred tax liabilities	3,922	40,400	2
Net deferred tax asset	$ —	$ 7,563	$ —

The company recognized income tax expense of $7.3 million in 2020 and an income tax benefit of $7.6 million in 2019. The net change is primarily related to the recognition of the valuation allowance against the Oklahoma state tax deferred asset that was not realized as a result of the Oklahoma water asset sale as previously expected.

The Company has an available federal tax net operating loss carryforward estimated at approximately $1.9 billion as of December 31, 2020. These federal net operating loss carryforwards generated in tax years prior to 2018 will begin to expire in 2023. As a result of the Tax Cuts and Jobs Act, the 2018 through 2020 federal NOL carryforwards have no expiration. The Company also has state net operating loss carryovers of $441.0 million that began to expire in 2019 and federal foreign tax credit carryovers of $0.5 million that will expire in 2021.

At each reporting period, the Company weighs all available positive and negative evidence to determine whether its deferred tax assets are more likely than not to be realized. As a result of this analysis at December 31, 2020, the Company determined a valuation allowance was necessary with respect to its net deferred tax assets totaling $985.5 million.

There was an increase of $338.0 million, an increase of $439.5 million and a decrease of $86.8 million to the valuation allowance during 2020, 2019 and 2018, respectively. The increase in the valuation allowance in 2020 and 2019 was primarily due to increases in net deferred tax assets from pre-tax losses resulting from impairments in the Company's oil and natural gas properties. The decrease in the valuation allowance in 2018 was primarily due to decreases in net deferred tax assets due to pre-tax income.

On March 27, 2020, the CARES Act was enacted in response to the COVID-19 pandemic. The Act includes several significant provisions for corporations including allowing companies to carryback certain NOLs, increasing the amount of NOLs that corporations can use to offset income, and increasing the amount of deductible interest under section 163(j). The Company does not expect to be materially impacted by the CARES Act provision and does not anticipate the CARES Act to have a material effect on its ability to realized deferred tax assets.

The Company's ability to utilize NOL carryforwards and other tax attributes to reduce future federal taxable income is subject to potential limitations under Section 382 and its related tax regulations. The utilization of these attributes may be limited if certain ownership changes by 5% shareholders (as defined in Treasury regulations pursuant to Section 382) and the effects of stock issuances by the Company during any three-year period result in a cumulative change or more than 50% in the beneficial ownership of the Company. As of December 31, 2020, the Company has completed a Section 382 analysis, which reflects that no ownership change has occurred to further limit the use of NOL carryforwards or other tax attributes. There are conditions that exist that are beyond the Company's control which could cause an ownership change in the future and create a significant limitation on the Company's ability to utilize those tax attributes. On April 30, 2020, the board of directors of the Company adopted a tax benefits preservation plan in order to protect against a possible limitation on the Company's ability to use its tax net operating losses and certain other tax benefits to reduce potential future U.S. federal income tax obligations. The Tax Benefits Preservation Plan is intended to prevent against such an ownership change by deterring any person or group from acquiring beneficial ownership of 4.9% or more of the Company's securities.

As of December 31, 2020, the Company has recorded a liability associated with uncertain tax positions of $3.8 million, which is included in liabilities subject to compromise in the accompanying consolidated balance sheet as of December 31, 2020.

12. EARNINGS PER SHARE

Reconciliations of the components of basic and diluted net income per common share are presented in the tables below:

	For the Year Ended December 31,		
	2020	**2019**	**2018**
	(In thousands, except share data)		
Net (loss) income	$ (1,625,133)	$ (2,002,358)	$ 430,560
Basic Shares	160,231,335	160,341,125	174,675,840
Basic EPS	$ (10.14)	$ (12.49)	$ 2.46
Effect of dilutive securities:			
Stock options and awards	—	—	722,866
Dilutive Shares	160,231,335	160,341,125	175,398,706
Dilutive EPS	$ (10.14)	$ (12.49)	$ 2.45

There were no potential shares of common stock that were considered anti-dilutive for the year ended December 31, 2020, 3,867,084 shares for the year ended December 31, 2019, and no potential shares of common stock that were considered anti-dilutive for the year ended December 31, 2018.

13. DERIVATIVE INSTRUMENTS

Natural Gas, Oil and Natural Gas Liquids Derivative Instruments

The Company seeks to mitigate risks related to unfavorable changes in natural gas, oil and NGL prices, which are subject to significant and often volatile fluctuation, by entering into over-the-counter fixed price swaps, basis swaps, collars and various types of option contracts. These contracts allow the Company to mitigate the impact of declines in future natural gas, oil and NGL prices by effectively locking in floor price for a certain level of the Company's production. However, these hedge contracts also limit the benefit to the Company in periods when the future market prices of natural gas, oil and NGL that are higher than the hedged prices.

Fixed price swaps are settled monthly based on differences between the fixed price specified in the contract and the referenced settlement price. When the referenced settlement price is less than the price specified in the contract, the Company receives an amount from the counterparty based on the price difference multiplied by the volume. Similarly, when the referenced settlement price exceeds the price specified in the contract, the Company pays the counterparty an amount based on the price difference multiplied by the volume. The prices contained in these fixed price swaps are based on the NYMEX Henry Hub for natural gas. Below is a summary of the Company's open fixed price swap positions as of December 31, 2020.

	Index	Daily Volume (MMBtu/day)	Weighted Average Price
2021	NYMEX Henry Hub	410,000	$ 2.75

The Company entered into costless collars based off the NYMEX Henry Hub natural gas index. Each two-way price collar has a set floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, the Company will cash-settle the difference with the counterparty.

	Index	Daily Volume (MMBtu/day)	Weighted Average Floor/Ceiling Price
2021	NYMEX Henry Hub	250,000	$2.46/$2.81
2022	NYMEX Henry Hub	20,000	$2.80/$3.40

In the third quarter of 2019, the Company sold call options in exchange for a premium, and used the associated premiums received to enhance the fixed price for a portion of the fixed price natural gas swaps primarily for 2020. Each short call option has an established ceiling price. When the referenced settlement price is above the price ceiling established by these short call options, the Company pays its counterparty an amount equal to the difference between the referenced settlement price and the price ceiling multiplied by the hedged contract volumes.

	Index	Daily Volume (MMBtu/day)	Weighted Average Price
2022	NYMEX Henry Hub	153,000	$ 2.90
2023	NYMEX Henry Hub	628,000	$ 2.90

In addition, the Company entered into natural gas basis swap positions. As of December 31, 2020, the Company had the following natural gas basis swap positions open:

	Gulfport Pays	Gulfport Receives	Daily Volume (MMBtu/day)	Weighted Average Fixed Spread
2021	Rex Zone 3	NYMEX Plus Fixed Spread	35,000	$ (0.21)
2021	Tetco M2	NYMEX Plus Fixed Spread	60,000	$ (0.67)

Contingent Consideration Arrangement

The purchase and sale agreement for the sale of the Company's non-core assets located in the WCBB and Hackberry fields of Louisiana included a contingent consideration arrangement that entitles the Company to receive bonus payments if commodity prices exceed specified thresholds. The calculated fair value of this contingent payment arrangement was approximately $1.1 million as of the closing date of the divestiture. See below for threshold and potential payment amounts.

Period	Threshold(1)	Payment to be received(2)
January 2021 - June 2021	Greater than or equal to $60.65	$ 150,000
	Between $52.62 - $60.65	Calculated Value(3)
	Less than or equal to $52.62	$ —

(1) Based on the "WTI NYMEX + Argus LLS Differential," as published by Argus Media.
(2) Payment will be assessed monthly from July 2020 through June 2021. If threshold is met, payment shall be received within five business days after the end of each calendar month.
(3) If average daily price, as defined in (1), is greater than $52.62 but less than $60.65, payment received will be $150,000 multiplied by a fraction, the numerator of which is the amount determined by subtracting $52.62 from such average daily price, and the denominator of which is $8.03.

Balance sheet presentation

The Company reports the fair value of derivative instruments on the consolidated balance sheets as derivative instruments under current assets, noncurrent assets, current liabilities, and noncurrent liabilities on a gross basis. The Company determines the current and noncurrent classification based on the timing of expected future cash flows of individual trades. The following table presents the fair value of the Company's derivative instruments on a gross basis at December 31, 2020 and 2019:

	December 31,	
	2020	2019
	(In thousands)	
Commodity derivative instruments	$ 27,146	$ 125,383
Contingent consideration arrangement	—	818
Total short-term derivative instruments – asset	$ 27,146	$ 126,201
Commodity derivative instruments	322	—
Contingent consideration arrangement	—	563
Total long-term derivative instruments – asset	$ 322	$ 563
Total short-term derivative instruments – liability	$ 11,641	$ 303
Total long-term derivative instruments – liability	$ 36,604	$ 53,135

Gains and losses

The following table presents the gain and loss recognized in net gain (loss) on natural gas, oil and NGL derivatives in the accompanying consolidated statements of operations for the years ended December 31, 2020, 2019, and 2018.

	Net gain (loss) on derivative instruments		
	For the Year Ended December 31,		
	2020	2019	2018
	(In thousands)		
Natural gas derivatives	$ 23,765	$ 194,450	$ (116,130)
Oil derivatives	43,510	7,035	(13,084)
NGL derivatives	(603)	6,632	5,735
Contingent consideration arrangement	(1,381)	243	—
Total	$ 65,291	$ 208,360	$ (123,479)

Offsetting of derivative assets and liabilities

As noted above, the Company records the fair value of derivative instruments on a gross basis. The following table presents the gross amounts of recognized derivative assets and liabilities in the consolidated balance sheets and the amounts that are subject to offsetting under master netting arrangements with counterparties, all at fair value.

	As of December 31, 2020		
	Derivative instruments, gross	Netting adjustments	Derivative instruments, net
	(In thousands)		
Derivative assets	$ 27,468	$ (25,730)	$ 1,738
Derivative liabilities	$ (48,245)	$ 25,730	$ (22,515)

	As of December 31, 2019		
	Derivative instruments, gross	Netting adjustments	Derivative instruments, net
		(In thousands)	
Derivative assets	$ 126,764	$ (53,438)	$ 73,326
Derivative liabilities	$ (53,438)	$ 53,438	$ —

Concentration of Credit Risk

By using derivative instruments that are not traded on an exchange, the Company is exposed to the credit risk of its counterparties. Credit risk is the risk of loss from counterparties not performing under the terms of the derivative instrument. When the fair value of a derivative instrument is positive, the counterparty is expected to owe the Company, which creates credit risk. To minimize the credit risk in derivative instruments, it is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The Company's derivative contracts are with multiple counterparties to lessen its exposure to any individual counterparty. Additionally, the Company uses master netting agreements to minimize credit risk exposure. The creditworthiness of the Company's counterparties is subject to periodic review. None of the Company's derivative instrument contracts contain credit-risk related contingent features. Other than as provided by the Company's revolving credit facility, the Company is not required to provide credit support or collateral to any of its counterparties under its derivative instruments, nor are the counterparties required to provide credit support to the Company.

14. RESTRUCTURING AND LIABILITY MANAGEMENT EXPENSES

In the third quarter of 2020 and fourth quarter of 2019, the Company announced and completed workforce reductions representing approximately10% and 13%, respectively, of its headcount. Restructuring charges related to the reduction in workforce primarily consisted of one-time employee-related termination benefits. Additionally, the Company incurred charges related to financial and legal advisors engaged to assist with the evaluation of a range of liability management alternatives during 2020 prior to the filing of the Chapter 11 Cases.

The following table summarizes the expenses related to the Company's reductions in workforce as well as expenses incurred related to liability management efforts in the accompanying consolidated statements of operations for the years ended December 31, 2020 and 2019:

	For the Year Ended December 31,	
	2020	2019
	(in thousands)	
Reduction in workforce	$ 1,460	$ 4,611
Liability management	29,387	—
Total restructuring and liability management expenses	$ 30,847	$ 4,611

15. FAIR VALUE MEASUREMENTS

The Company records certain financial and non-financial assets and liabilities on the balance sheet at fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. Market or observable inputs are the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. Fair value measurements are classified and disclosed in one of the following categories:

Level 1 – Quoted prices in active markets for identical assets and liabilities.

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

Level 3 – Significant inputs to the valuation model are unobservable.

Valuation techniques that maximize the use of observable inputs are favored. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Reclassifications of fair value between Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter.

Financial assets and liabilities

The following tables summarize the Company's financial assets and liabilities by valuation level as of December 31, 2020 and 2019:

	December 31, 2020		
	Level 1	Level 2	Level 3
		(In thousands)	
Assets:			
Derivative Instruments	$ —	$ 27,468	$ —
Contingent consideration arrangement	$ —	$ —	$ 6,200
Total assets	$ —	$ 27,468	$ 6,200
Liabilities:			
Derivative Instruments	$ —	$ 48,245	$ —

	December 31, 2019		
	Level 1	Level 2	Level 3
		(In thousands)	
Assets:			
Derivative Instruments	$ —	$ 126,764	$ —
Liabilities:			
Derivative Instruments	$ —	$ 53,438	$ —

The Company estimates the fair value of all derivative instruments using industry-standard models that considered various assumptions including current market and contractual prices for the underlying instruments, implied volatility, time value, nonperformance risk, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be supported by observable data.

As discussed in Note 3, the water infrastructure sale included a contingent consideration arrangement. As of December 31, 2020, the fair value of the contingent consideration was $6.2 million, of which $1.1 million is included in prepaid expenses and other assets and $5.1 million is included in other assets in the accompanying consolidated balance sheets. The fair value of the contingent consideration arrangement is calculated using discounted cash flow techniques and is based on internal estimates of the Company's future development program and water production levels. Given the unobservable nature of the inputs, the fair value measurement of the contingent consideration arrangement is deemed to use Level 3 inputs. The Company has elected the fair value option for this contingent consideration arrangement and, therefore, records changes in fair value in earnings. As a result of a reduction in the future anticipated contingent consideration since the acquisition date, the Company recognized a loss of $16.6 million on changes in fair value of the contingent consideration during the year ended December 31, 2020, which is included in other expense (income) in the accompanying consolidated statements of operations. Settlements under the contingent consideration arrangement totaled $0.3 million during the year ended December 31, 2020.

Non-financial assets and liabilities

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 4 for further discussion of the Company's asset retirement obligations. Asset retirement obligations incurred during the year ended December 31, 2020 were approximately $2.4 million.

The Company did not record any other than temporary impairments on its equity method investments during the year ended December 31, 2020, however the Company recorded impairments on its investments during the year ended December 31, 2019. Due to the unobservable nature of the inputs, the fair value of the Company's investment in Grizzly as of December 31, 2019 was estimated using assumptions that represent Level 3 inputs. The fair value of the Company's investment in Mammoth Energy as of December 31, 2019 was estimated using Level 1 inputs, as the price per share was a quoted price in an active market for identical Mammoth Energy common shares.

Fair value of other financial instruments

The carrying amounts on the accompanying consolidated balance sheet for cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and current debt are carried at cost, which approximates market value due to their short-term nature. Long-term debt related to the Company's construction loan is carried at cost, which approximates market value based on the borrowing rates currently available to the Company with similar terms and maturities. See Note 6 for fair value of Company's long-term debt.

16. RELATED PARTY TRANSACTIONS

In the ordinary course of business, the Company has conducted business activities with certain related parties.

As of December 31, 2020, the Company held approximately21.5% of Mammoth Energy's outstanding common stock as discussed above inNote 5. Approximately $0.6 million, and $2.0 million of services provided by Mammoth Energy were included in lease operating expenses in the consolidated statements of operations for the years ended December 31, 2019 and 2018, respectively, with no material amounts for the year ended December 31, 2020. Approximately $3.1 million and $109.9 million of services provided by Mammoth Energy were capitalized to oil and natural gas properties before elimination of intercompany profits on the accompanying consolidated balance sheets during the years ended December 31, 2020 and 2019, respectively. At December 31, 2019, the Company owed Mammoth Energy approximately $8.4 million related to these services. Amounts owed to Mammoth Energy as of December 31, 2020 were immaterial.

See Note 18 for additional information on litigation proceedings with Mammoth Energy entities.

17. COMMITMENTS

Firm Transportation and Gathering Agreements

The Company has contractual commitments with pipeline carriers for future gathering and transportation of natural gas from the Company's producing wells to downstream markets. Under certain of these agreements, the Company has minimum daily volume commitments. The Company is also obligated under certain of these arrangements to pay a demand charge for firm capacity rights on pipeline systems regardless of the amount of pipeline capacity utilized by the Company. If the Company does not utilize the capacity, it often can release it to other counterparties, thus reducing its potential liability. Commitments related to future firm transportation and gathering agreements are not recorded as obligations in the accompanying consolidated balance sheets; however, they are reflected in the Company's estimates of proved reserves.

Additionally, one of the requirements provided for in the RSA is that the Company must permanently reduce its future demand reservation fees owed over the life of all of its firm transportation agreements, taken as a whole, by at least 50% of the amount of all such fees owed on October 31, 2020, as calculated on a PV-10 basis. Additionally, the Company must reduce the future firm transportation demand reservation volumes over the life of all of its firm transportation agreements, taken as a whole, by at least 35%. The below table reflects the Company's obligations as of December 31, 2020 excluding contemplation of contracts to be rejected throughout the Chapter 11 Cases.

A summary of these commitments at December 31, 2020 are set forth in the table below:

		(In thousands)
2021	$	370,343
2022		380,979
2023		379,171
2024		358,990
2025		272,123
Thereafter		2,013,119
Total	$	3,774,725

Future Sales Commitments

The Company has entered into various firm sales contracts with third parties to deliver and sell natural gas. The Company expects to fulfill its delivery commitments primarily with production from proved developed reserves. The Company's proved reserves have generally been sufficient to satisfy its delivery commitments during the three most recent years, and it expects such reserves will continue to be the primary means of fulfilling its future commitments. However, where the Company's proved reserves are not sufficient to satisfy its delivery commitments, it can and may use spot market purchases of third party production to satisfy these commitments.

A summary of these commitments at December 31, 2020 are set forth in the table below:

	(MMBtu per day)
2021	88,000
2022	58,000
2023	17,000
2024	—
2025	—
Thereafter	—
Total	163,000

Contributions to 401(k) Plan

Gulfport sponsors a 401(k) plan under which eligible employees may contribute a portion of their total compensation up to the maximum pre-tax threshold through salary deferrals. The plan is considered a Safe Harbor 401(k) and provides a company match on 100% of salary deferrals that do not exceed4% of compensation in addition to a match of 50% of salary deferrals that exceed4% but do not exceed 6% of compensation. The Company may also make discretionary elective contributions to the plan. During the years ended December 31, 2020, 2019 and 2018, Gulfport incurred $2.6 million, $2.9 million, and $2.6 million, respectively, in contributions expense related to this plan.

18. CONTINGENCIES

Litigation and Regulatory Proceedings

The Company is involved in a number of litigation and regulatory proceedings that may result in material liabilities, including those described below. Many of these proceedings are in early stages, and many of them seek or may seek damages and penalties, the amount of which is indeterminate. The Company's total accrued liabilities in respect of litigation and regulatory proceedings is determined on a case-by-case basis and represents an estimate of probable losses after considering, among other factors, the progress of each case or proceeding, its experience and the experience of others in similar cases or proceedings, and the opinions and views of legal counsel. Significant judgment is required in making these estimates and their final liabilities may ultimately be materially different.

The Company, along with a number of other oil and gas companies, has been named as a defendant intwo separate complaints, one filed by the State of Louisiana and the Parish of Cameron in the 38th Judicial District Court for the Parish of Cameron on February 9, 2016 and the other filed by the State of Louisiana and the District Attorney for the 15th Judicial District of the State of Louisiana in the 15th Judicial District Court for the Parish of Vermilion on July 29, 2016 (together, the "Complaints"). The Complaints allege that certain of the defendants' operations violated the State and Local Coastal Resources Management Act of 1978, as amended, and the rules, regulations, orders and ordinances adopted thereunder (the "CZM Laws") by causing substantial damage to land and waterbodies located in the coastal zone of the relevant Parish. The plaintiffs seek damages and other appropriate relief under the CZM Laws, including the payment of costs necessary to clear, re-vegetate, detoxify and otherwise restore the affected coastal zone of the relevant Parish to its original condition, actual restoration of such coastal zone to its original condition, and the payment of reasonable attorney fees and legal expenses and interest. The United States District Court for the Western District of Louisiana issued orders remanding the cases to their respective state court, and the defendants have appealed the remand orders to the 5th Circuit Court of Appeals.

In July 2019, Pigeon Land Company, Inc., a successor in interest to certain of the Company's legacy Louisiana properties, filed an action against the Company and a number of other oil and gas companies in the 16th Judicial District Court for the Parish of Iberia in Louisiana. The suit alleged negligence, strict liability and various violations of Louisiana statutes relating to property damage in connection with the historic development of the Company's Louisiana properties and sought unspecified damages (including punitive damages), an injunction to return the affected property to its original condition, and the payment of reasonable attorney fees and legal expenses and interest. This matter was voluntarily dismissed without prejudice on December 8, 2020.

In September 2019, a stockholder of Mammoth Energy filed a derivative action on behalf of Mammoth Energy against members of Mammoth Energy's board of directors, including a director designated by the Company, and its significant stockholders, including the Company, in the United States District Court for the Western District of Oklahoma. In January 2020, plaintiffs consolidated actions against the same defendants in the United States District Court for the District of Delaware. The consolidated and amended complaint alleges, among other things, that the Company breached its fiduciary duties and misappropriated information as a controlling shareholder of Mammoth Energy in connection with Mammoth Energy's activities in Puerto Rico following Hurricane Maria and the Company's secondary offering of Mammoth Energy common stock in June 2018. The complaint seeks unspecified damages, the payment of reasonable attorney fees and legal expenses and interest and to force Mammoth Energy and its board of directors to make specified corporate governance reforms.

In October 2019, Kelsie Wagner, in her capacity as trustee of various trusts and on behalf of the trusts and other similarly situated royalty owners, filed an action against us in the District Court of Grady County, Oklahoma. The suit alleged that the Company underpaid royalty owners and seeks unspecified damages for violations of the Oklahoma Production Revenue Standards Act and fraud. This matter is settled in principal and a voluntary dismissal without prejudice is anticipated.

In March 2020, Robert F. Woodley, individually and on behalf of all others similarly situated, filed a federal securities class action against the Company, David M. Wood, Keri Crowell and Quentin R. Hicks in the United States District Court for the Southern District of New York. The complaint alleges that the Company made materially false and misleading statements regarding the Company's business and operations in violation of the federal securities laws and seeks unspecified damages, the payment of reasonable attorneys' fees, expert fees and other costs, pre-judgment and post-judgment interest, and such other and further relief that may be deemed just and proper.

In June 2020, Sam L. Carter, derivatively on behalf of the Company, filed an action against certain of our current and former executive officers and directors in the United States District Court for the District of Delaware. The complaint alleged that the defendants breached their fiduciary duties to the Company in connection with certain alleged materially false and misleading statements regarding our business and operations in violation of the federal securities laws. The complaint sought to recover unspecified damages from the defendants, the implementation of specified corporate governance reforms, reasonable attorneys' and experts' fees, costs and expenses, and such other relief as may be deemed just and proper. The complaint was voluntarily dismissed without prejudice on October 6, 2020.

The Company filed a lawsuit against Stingray Pressure Pumping LLC, a subsidiary of Mammoth Energy ("Stingray"), for breach of contract and to terminate the Master Services Agreement for pressure pumping services, effective as of October 1, 2014, as amended (the "Master Services Agreement"), between Stingray and the Company. In March 2020, Stingray filed a counterclaim against the Company in the Superior Court of the State of Delaware. The counterclaim alleges that the Company has breached the Master Services Agreement. The counterclaim seeks actual damages, and Stingray filed claims in the Chapter 11 proceedings totaling $43.4 million related to breach of contract damages, attorneys' fees and interest.

In April 2020, Bryon Lefort, individually and on behalf of similarly situated individuals, filed an action against the Company in the United States District Court for the Southern District of Ohio Eastern Division. The complaint alleges that the Company violated the Fair Labor Standards Act ("FLSA"), the Ohio Wage Act and the Ohio Prompt Pay Act by classifying the plaintiffs as independent contractors and paying them a daily rate with no overtime compensation for hours worked in excess of 40 hours per week. The complaint seeks to recover unpaid regular and overtime wages, liquidated damages in an amount equal to six of all unpaid overtime compensation, the payment of reasonable attorney fees and legal expenses and pre-judgment and post-judgment interest, and such other damages that may be owed to the workers.

In August 2020, Muskie filed an action against the Company in the Superior Court of the State of Delaware for breach of contract. The complaint alleges that the Company breached its obligation to purchase a certain amount of proppant sand each month or make designated shortfall payments under the Sand Supply Agreement, effective October 1, 2014, as amended (the "Sand Supply Agreement"), between Muskie and the Company, and seeks payment of unpaid shortfall payments, and Muskie filed a claim in the Chapter 11 proceedings for $3.4 million.

SEC Investigation

The SEC has commenced an investigation with respect to certain actions by former Company management, including alleged improper personal use of Company assets, and potential violations by former management and the Company of the Sarbanes-Oxley Act of 2002 in connection with such actions. On February 24, 2021, without admitting or denying any of findings contained in the order, Gulfport resolved the SEC investigation through an administrative order that Gulfport violated Sections 13(a), 13(b)(2)(A), 13(b)(2)(B) and 14(a) of the Exchange Act and Rules 12b-20, 13a-1, 14a-3 and 14a-9. Under the administrative order and pursuant to Section 21C of the Exchange Act, Gulfport agreed to cease and desist from committing or causing any violations and any future violations of Sections 13(a), 13(b)(2)(A), 13(b)(2)(B) and 14(a) of the Exchange Act and Rules 12b-20, 13a-1, 14a-3 and 14a-9 thereunder. Based on the company's extensive cooperation and prompt remedial efforts, the SEC did not impose a monetary penalty.

Business Operations

The Company is involved in various lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions.

Environmental Contingencies

The nature of the oil and gas business carries with it certain environmental risks for Gulfport and its subsidiaries. They have implemented various policies, programs, procedures, training and audits to reduce and mitigate such environmental risks. They conduct periodic reviews, on a company-wide basis, to assess changes in their environmental risk profile. Environmental reserves are established for environmental liabilities for which economic losses are probable and reasonably estimable. The Company manages its exposure to environmental liabilities in acquisitions by using an evaluation process that seeks to identify pre-existing contamination or compliance concerns and address the potential liability. Depending on the extent of an identified environmental concern, they may, among other things, exclude a property from the transaction, require the seller to remediate the property to their satisfaction in an acquisition or agree to assume liability for the remediation of the property.

The Company received several Finding of Violation ("FOVs") from the USEPA alleging violations of the Clean Air Act in Ohio. The Company entered into a settlement with the Department of Justice and USEPA agreeing to pay $1.7 million and invest in improvements at 17 well pads. The settlement was filed with the U.S. District Court for the Southern District of Ohio in January 2020 and was fully paid in October 2020.

Other Matters

Based on management's current assessment, they are of the opinion that no pending or threatened lawsuit or dispute relating to its business operations is likely to have a material adverse effect on their future consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management's estimates.

Concentration of Credit Risk

Gulfport operates in the oil and natural gas industry principally in the states of Ohio and Oklahoma with sales to refineries, re-sellers such as marketers, and other end users. While certain of these customers are affected by periodic downturns in the economy in general or in their specific segment of the oil and gas industry, Gulfport believes that its level of credit-related losses due to such economic fluctuations has been immaterial and will continue to be immaterial to the Company's results of operations in the long term.

The Company maintains cash balances at several banks. Accounts at each institution are insured by the Federal Deposit Insurance Corporation. At December 31, 2020, Gulfport held no cash in excess of insured limits in these banks.

During the year ended December 31, 2020, one customer accounted for approximately 12% of the Company's total sales. During the year ended December 31, 2019, one customer accounted for approximately 14% of the Company's total sales. During the year ended December 31, 2018, two customers accounted for approximately 17% and 10% of the Company's total sales. The Company does not believe that the loss of any of these customers would have a material adverse effect on its natural gas, oil and condensate and NGL sales as alternative customers are readily available.

19. SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (UNAUDITED)

The Company owns a 24.5% interest in Grizzly. However, Grizzly did not have any material activity or proved reserves in the years presented below. As such, amounts related to Grizzly have been omitted below.

The following is historical revenue and cost information relating to the Company's oil and gas operations located entirely in the United States:

Capitalized Costs Related to Oil and Gas Producing Activities

	2020	2019
	(In thousands)	
Proved properties	$ 9,359,866	$ 8,909,069
Unproved properties	1,457,043	1,686,666
	10,816,909	10,595,735
Accumulated depreciation, depletion, amortization and impairment	(8,778,759)	(7,191,957)
Net capitalized costs	$ 2,038,150	$ 3,403,778

Costs Incurred in Oil and Gas Property Acquisition and Development Activities

	2020	2019	2018
		(In thousands)	
Acquisition	$ 15,260	$ 37,598	$ 119,444
Development	276,622	594,673	714,269
Exploratory	—	9,762	22,081
Total	$ 291,882	$ 642,033	$ 855,794

Capitalized interest is included as part of the cost of oil and natural gas properties. The Company capitalized $0.9 million, $3.4 million and $4.5 million during 2020, 2019, 2018, respectively, based on the Company's weighted average cost of borrowings used to finance expenditures.

In addition to capitalized interest, the Company capitalized internal costs totaling $25.0 million, $30.1 million and $37.7 million during 2020, 2019, and 2018, respectively, which were directly related to the acquisition, exploration and development of the Company's oil and natural gas properties.

Results of Operations for Producing Activities

The following schedule sets forth the revenues and expenses related to the production and sale of oil and natural gas. The income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include depreciation, depletion and amortization allowances, after giving effect to the permanent differences. The results of operations exclude general office overhead and interest expense attributable to oil and gas production.

	2020	2019	2018
		(In thousands)	
Revenues	$ 801,251	$ 1,354,766	$ 1,675,180
Production costs	(537,609)	(620,412)	(611,965)
Depletion	(229,702)	(539,379)	(476,517)
Impairment	(1,357,099)	(2,039,770)	—
Income tax (expense) benefit	(7,290)	7,563	68
Results of operations from producing activities	$ (1,330,449)	$ (1,837,232)	$ 586,766
Depletion per Mcf of gas equivalent (Mcfe)	$ 0.61	$ 1.08	$ 0.96

Oil and Natural Gas Reserves

The following table presents estimated volumes of proved developed and undeveloped oil and gas reserves as of December 31, 2020, 2019 and 2018 and changes in proved reserves during the last three years. The reserve reports use an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2020, 2019 and 2018, in accordance with guidelines of the SEC applicable to reserves estimates. The prices used for the 2020 reserve report are $39.54 per barrel of oil, $1.99 per MMbtu and $15.40 per barrel for NGL, adjusted by lease for transportation fees and regional price differentials, and for oil and gas reserves, respectively. The prices used at December 31, 2019 and 2018 for reserve report purposes are $55.85 per barrel, $2.58 per MMbtu and $21.25 per barrel for NGL and $65.56 per barrel, $3.10 per MMbtu and $32.02 per barrel for NGL, respectively.

Gulfport emphasizes that the volumes of reserves shown below are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data, as well as production performance data. These estimates are reviewed annually and revised, either upward or downward, as warranted by additional performance data.

	Oil (MMBbl)	Natural Gas (Bcf)	NGL (MMBbl)	Natural Gas Equivalent (Bcfe)
Proved Reserves				
December 31, 2017	19	4,825	76	5,395
Purchases of reserves	—	—	—	—
Extensions and discoveries	5	622	10	711
Sales of reserves	—	(43)	—	(45)
Revisions of prior reserve estimates	—	(827)	1	(821)
Current production	(3)	(444)	(6)	(497)
December 31, 2018	21	4,134	81	4,743
Purchases of reserves	—	—	—	—
Extensions and discoveries	4	997	13	1,097
Sales of reserves	(2)	(63)	—	(77)
Revisions of prior reserve estimates	(2)	(562)	(27)	(734)
Current production	(2)	(458)	(5)	(502)
December 31, 2019	18	4,048	62	4,528
Purchases of reserves	—	—	—	—
Extensions and discoveries	1	216	3	240
Sales of reserves	—	(74)	—	(75)
Revisions of prior reserve estimates	(4)	(1,564)	(23)	(1,725)
Current production	(2)	(345)	(4)	(380)
December 31, 2020	13	2,281	38	2,588
Proved developed reserves				
December 31, 2018	10	1,813	41	2,115
December 31, 2019	8	1,757	30	1,984
December 31, 2020	7	1,358	22	1,527
Proved undeveloped reserves				
December 31, 2018	11	2,321	40	2,628
December 31, 2019	10	2,291	32	2,544
December 31, 2020	7	923	16	1,061

Totals may not sum or recalculate due to rounding.

In 2020, the Company experienced extensions of 239.8 Bcfe of estimated proved reserves, which were primarily attributable to the Company's continued development of its Utica and SCOOP acreages. Of the total extensions, 150.6 Bcfe was attributable to the addition of 14 PUD locations in the Utica field, 87.8 Bcfe was attributable to the addition of eight PUD locations in the SCOOP field. The Company experienced total downward revisions of approximately 1.7 Tcfe in estimated proved reserves, of which 1,268.4 Bcfe was the result of commodity price changes. Commodity prices experienced volatility throughout 2020 and the 12-month average price for natural gas decreased from $2.58 per MMBtu for 2019 to $1.99 per MMBtu for 2020, the 12-month average price for NGL decreased from $21.25 per barrel for 2019 to $15.40 per barrel for 2020, and the 12-month average price for crude oil decreased from $55.85 per barrel for 2019 to $39.54 per barrel for 2020. An additional 720.3 Bcfe in downward revisions was a result of the exclusion of 48 PUD locations in the Utica field and 31 PUD locations in the SCOOP field, which was a result of changes in the Company's schedule that moved development of these PUD locations beyond five years of initial booking. The development plan change reflects the Company's commitment to capital discipline, funding future activities within cash flow and ongoing optimization of our development plan. Positive revisions of 263.8 Bcfe were experienced from a combination of operating and development cost improvements, well performance and working interest changes.

In 2019, the Company experienced extensions of 1.1 Tcfe of estimated proved reserves, which were primarily attributable to the Company's continued development of its Utica and SCOOP acreages. Of the total extensions, 793.5 Bcfe was attributable to the addition of 72 PUD locations in the Utica field, 302.9 Bcfe was attributable to the addition of 37 PUD locations in the SCOOP field. The Company experienced total downward revisions of approximately 733.8 Bcfe in estimated proved reserves, of which 347.2 Bcfe was a result of the exclusion of nine PUD locations in the Utica field and 22 PUD locations in the SCOOP field, which was a result of changes in the Company's schedule that moved development of these PUD locations beyond five years of initial booking. The development plan change reflects the Company's commitment capital discipline and funding future activities within cash flow. An additional 296.4 Bcfe in downward revisions was the result of commodity price changes. Commodity prices experienced volatility throughout 2019 and the 12-month average price for natural gas decreased from $3.10 per MMBtu for 2018 to $2.58 per MMBtu for 2019, the 12- month average price for NGL decreased from $32.02 per barrel for 2018 to $21.25 per barrel for 2019, and the 12-month average price for crude oil decreased from $65.56 per barrel for 2018 to $55.85 per barrel for 2019. The Company also experienced downward revisions of 90.2 Bcfe from a combination of working interest changes, optimization of well design in the current commodity price environment and well performance.

In 2018, the Company experienced extensions and discoveries of 711.2 Bcfe of estimated proved reserves, which were primarily attributable to the Company's continued development of its Utica and SCOOP acreages. Of the total extensions and discoveries, 556.3 Bcfe was attributable to the addition of 75 PUD locations in the Utica field, 90.1 Bcfe was attributable to the addition of 11 PUD locations in the SCOOP field and 3.0 Bcfe was attributable to the addition of 13 PUD locations in the Southern Louisiana fields as a result of the Company's current development plan that refocused some activity within existing fields. This change reflects the Company's ongoing efforts to optimize the development program with well selection based on economic returns, commodity mix and surface considerations.

In 2018, the Company experienced downward revisions of 1.0 Tcfe in estimated proved reserves with the exclusion of 127 PUD locations in the Company's Utica field and 12 PUD locations in the Company's SCOOP field, which was primarily the result of changes in the Company's development schedule moving development in excess of five years from initial booking. The development plan change, as approved by the Company's senior management and board of directors, is a result of continued focus on free cash flow generation. This downward revision was partially offset by upward revisions of 82.4 Bcfe in estimated proved reserves in 2018 due to changes in wellbore lateral length, 67.6 Bcfe due to changes in ownership interest, 27.9 Bcfe due to an increase in pricing and 8.3 Bcfe due to changes in well performance. In addition, the Company sold approximately 44.9 Bcfe of proved undeveloped oil and natural gas reserves associated with various non-operated interests, the majority of which were in the Company's Utica field.

Discounted Future Net Cash Flows

The following tables present the estimated future cash flows, and changes therein, from Gulfport's proven oil and gas reserves as of December 31, 2020, 2019 and 2018 using an unweighted average first-of-the-month price for the period January through December 31, 2020, 2019 and 2018.

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

	Year ended December 31,		
	2020	**2019**	**2018**
		(In millions)	
Future cash flows	$ 4,079	$ 10,451	$ 14,483
Future development and abandonment costs	(652)	(2,058)	(2,438)
Future production costs	(2,325)	(4,513)	(5,068)
Future production taxes	(137)	(333)	(456)
Future income taxes	—	—	(943)
Future net cash flows	965	3,547	5,578
10% discount to reflect timing of cash flows	(425)	(1,844)	(2,596)
Standardized measure of discounted future net cash flows	$ 540	$ 1,703	$ 2,982

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

	Year ended December 31,		
	2020	2019	2018
	(In millions)		
Sales and transfers of oil and gas produced, net of production costs	$ (264)	$ (734)	$ (1,063)
Net changes in prices, production costs, and development costs	(954)	(1,372)	591
Acquisition of oil and gas reserves in place	—	—	—
Extensions and discoveries	38	388	519
Previously estimated development costs incurred during the period	215	406	402
Revisions of previous quantity estimates, less related production costs	(255)	(321)	(357)
Sales of oil and gas reserves in place	(6)	(49)	(26)
Accretion of discount	170	298	264
Net changes in income taxes	—	425	(185)
Change in production rates and other	(109)	(319)	194
Total change in standardized measure of discounted future net cash flows	$ (1,165)	$ (1,278)	$ 339

20. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table summarizes quarterly financial data for the years ended December 31, 2020 and 2019:

	2020			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands)			
Revenues	$ 299,338	$ 186,301	$ 136,176	$ 244,727
(Loss) income from operations	(480,087)	(555,750)	(346,400)	19,632
Income tax expense	7,290	—	—	—
Net loss	(517,538)	(561,068)	(380,963)	(165,564)
Loss per share:				
Basic	$ (3.24)	$ (3.51)	$ (2.37)	$ (1.03)
Diluted	$ (3.24)	$ (3.51)	$ (2.37)	$ (1.03)

	2019			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands)			
Revenues	$ 372,462	$ 512,451	$ 341,745	$ 336,468
(Loss) income from operations	93,011	218,456	(570,955)	(1,444,205)
Income tax (benefit) expense	—	(179,331)	(144,047)	315,815
Net income (loss)	62,242	234,956	(484,802)	(1,814,754)
Income (loss) per share:				
Basic	$ 0.38	$ 1.47	$ (3.04)	$ (11.36)
Diluted	$ 0.38	$ 1.47	$ (3.04)	$ (11.36)

21. SUBSEQUENT EVENTS

Subsequent to December 31, 2020 and as of March 1, 2021, the Company entered into the following natural gas, oil, and NGL derivative contracts as it works toward fulfilling minimum hedging requirements as provided for in the RSA:

Period	Type of Derivative Instrument	Index	Daily Volume(1)	Weighted Average Price
July 2021 - December 2021	Swaps	NYMEX WTI	2,250	$53.07
July 2021 - December 2021	Swaps	Mont Belvieu C3	3,100	$27.80
January 2022 - June 2022	Swaps	Mont Belvieu C3	1,000	$27.30
April 2021 - May 2021	Basis Swaps	Tetco M2	36,443	$(0.61)
February 2021 - October 2021	Basis Swaps	Rex Zone 3	94,505	$(0.22)
July 2021 - December 2021	Costless Collars	NYMEX Henry Hub	210,000	$2.67/$3.15
January 2022 - March 2022	Costless Collars	NYMEX Henry Hub	340,000	$2.82/$3.40

(1) Volume units for gas instruments are presented as MMBtu/day while oil and NGL is presented in Bbls/day.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures

Under the direction of our Chief Executive Officer and President and our Chief Financial Officer, we have established disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and President and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

As of December 31, 2020, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and President and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and President and our Chief Financial Officer have concluded that, as of December 31, 2020, our disclosure controls and procedures are effective.

Remediation of Previously Identified Material Weakness

As disclosed in our Annual Report on Form 10-K for the year ended December 31, 2019, our management determined that a material weakness existed in our internal control over financial reporting over the review of the evaluation of our unevaluated oil and gas properties.

We have taken the necessary steps to enhance the underlying control activities, which now include redesigned processes and controls to timely identify the transfer of leasehold costs associated with acreage expirations, lease transfers, and proved reserve additions in conjunction with our current development plans.

Based on the results of management's evaluation, we have concluded that the controls are designed and operating effectively as of December 31, 2020 and, therefore, the previously disclosed material weakness has been remediated.

Changes in Internal Control over Financial Reporting

During the quarter ended December 31, 2020, we added certain key controls related to our ongoing reorganization.

Except as described above, there were no changes in our internal control over financial reporting during the quarter ended December 31, 2020, which materially affected, or were reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for the fair presentation of the consolidated financial statements of Gulfport Energy Corporation. Management is also responsible for establishing and maintaining a system of adequate internal controls over financial reporting as defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. These internal controls are designed to provide reasonable assurance that the reported financial information is presented fairly, that disclosures are adequate and that the judgments inherent in the preparation of financial statements are reasonable. There are inherent limitations in the effectiveness of any system of internal control, including the possibility of human error and overriding of controls. Consequently, an effective internal control system can only provide reasonable, not absolute, assurance with respect to reporting financial information.

Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in the *2013 Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in the 2*013 Internal Control-Integrated Framework,* management did not identify and material weakness in our internal control over financial reporting and concluded that out internal control over financial reporting was effective as of December 31, 2020.

Grant Thornton LLP, the independent registered public accounting firm that audited our financial statements for the year ended December 31, 2020 included with this Annual Report on Form 10-K, has also audited our internal control over financial reporting as of December 31, 2020, as stated in their accompanying report.

/s/ David M. Wood		/s/ Quentin Hicks	
Name:	David M. Wood	Name:	Quentin Hicks
Title:	Chief Executive Officer and President, Director	Title:	Chief Financial Officer

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Gulfport Energy Corporation

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Gulfport Energy Corporation (a Delaware corporation) and subsidiaries (Debtor-in-Possession) (the "Company") as of December 31, 2020, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2020, and our report dated March 5, 2021 expressed an unqualified opinion on those financial statements.

Basis for opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and limitations of internal control over financial reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 5, 2021

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The names of executive officers and certain other senior officers of the Company and their ages, titles and biographies as of the date hereof are incorporated by reference from Item 1 of Part I of this report. The other information called for by this Item 10 is incorporated herein by reference to the definitive proxy statement to be filed by Gulfport pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2021 (the 2021 Proxy Statement).

ITEM 11. EXECUTIVE COMPENSATION

The information called for by this Item 11 is incorporated herein by reference to the 2021 Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information called for by this Item 12 is incorporated herein by reference to the 2021 Proxy Statement.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information called for by this Item 13 is incorporated herein by reference to the 2021 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information called for by this Item 14 is incorporated herein by reference to the 2021 Proxy Statement.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following financial statements, financial statement schedules and exhibits are filed as part of this report:

1. *Financial Statements.* Gulfport's consolidated financial statements are included in Item 8 of Part II of this report. Reference is made to the accompanying Index to Financial Statements.
2. *Financial Statement Schedules.* No financial statement schedules are applicable or required.
3. *Exhibits.* The exhibits listed below in the Index of Exhibits are filed, furnished or incorporated by reference pursuant to the requirements of Item 601 of Regulation S-K.

INDEX OF EXHIBITS

Exhibit Number	Description	Incorporated by Reference				Filed or Furnished Herewith
		Form	SEC File Number	Exhibit	Filing Date	
3.1	Restated Certificate of Incorporation.	8-K	000-19514	3.1	4/26/2006	
3.2	Certificate of Amendment No. 1 to Restated Certificate of Incorporation.	10-Q	000-19514	3.2	11/6/2009	
3.3	Certificate of Amendment No. 2 to Restated Certificate of Incorporation.	8-K	000-19514	3.1	7/23/2013	
3.4	Second Amended and Restated Bylaws of Gulfport Energy Corporation.	8-K	000-19514	3.1	2/27/2020	
3.5	First Amendment to the Second Amended and Restated Bylaws of Gulfport Energy Corporation	8-K	001-19514	3.1	5/29/2020	
3.6	Certificate of Designation of Series B Junior Participating Preferred Stock of Gulfport Energy Corporation	8-A	001-19514	3.1	4/30/2020	
4.1	Form of Common Stock certificate.	SB-2	333-115396	4.1	7/22/2004	
4.2	Indenture, dated as of April 21, 2015, among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of the Company's 6.625% Senior Notes due 2023).	8-K	000-19514	4.1	4/21/2015	
4.3	Indenture, dated as of October 14, 2016, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of Gulfport Energy Corporation's 6.000% Senior Notes due 2024).	8-K	000-19514	4.1	10/19/2016	
4.4	Indenture, dated as of December 21, 2016, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of Gulfport Energy Corporation's 6.375% Senior Notes due 2025).	8-K	000-19514	4.1	12/21/2016	

4.5	Indenture, dated as of October 11, 2017, among Gulfport Energy Corporation, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as trustee (including the form of Gulfport Energy Corporation's 6.375% Senior Notes due 2026).	8-K	000-19514	4.1	10/11/2017
4.6	Tax Benefits Preservation Plan, dated as of April 30, 2020, between Gulfport Energy Corporation and Computershare Trust Company, N.A., as rights agent (which includes the Form of Rights Certificate as Exhibit B thereto)	8-A	001-19514	4.1	4/30/2020
10.1+	2019 Amended and Restated Stock Incentive Plan	DEF 14A	000-19514	Appendix A	4/30/19
10.2+	2019 Amended and Restated Stock Incentive Plan Form of Performance Share Award Agreement.	8-K	000-19514	10.3	8/12/19
10.3+	2014 Executive Annual Incentive Compensation Plan.	8-K	000-19514	10.1	4/7/2014
10.4+	Form of Stock Option Agreement.	8-K	000-19514	10.2	4/26/2006
10.5+	Form of Restricted Stock Award Agreement.	10-K	000-19514	10.3	2/28/2014
10.6+	2013 Restated Stock Incentive Plan.	S-4	333-189992	10.1	7/17/2013
10.7+	Gulfport Energy Corporation 2020 Incentive Plan.	8-K	000-19514	10.1	3/17/2020
10.8+	Form of 2020 Cash Award under Gulfport Energy Corporation 2020 Incentive Plan.	8-K	000-19514	10.2	3/17/2020
10.9	Employment Agreement, entered into and effective as of August 1, 2019, by and between Gulfport Energy Corporation and David M. Wood.	10-Q	000-19514	10.3	8/2/2019
10.10	Employment Agreement, entered into and effective as of August 1, 2019, by and between Gulfport Energy Corporation and Donnie Moore.	10-Q	000-19514	10.4	8/2/2019
10.11	Employment Agreement, entered into and effective as of August 1, 2019, by and between Gulfport Energy Corporation and Patrick K. Craine.	10-Q	000-19514	10.5	8/2/2019
10.12	Employment Agreement, effective as of August 26, 2019, by and between Gulfport Energy Corporation and Quentin Hicks.	8-K	000-19514	10.1	8/12/19
10.13	Employment Agreement dated November 13, 2020, by and between the Company and Michael Sluiter.	8-K	001-19514	10.4	11/16/2020
10.14	Amended and Restated Credit Agreement, dated as of December 27, 2013, by and among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and the other lenders party thereto.	8-K	000-19514	10.1	1/3/2014

10.15	First Amendment to Amended and Restated Credit Agreement, dated as of April 23, 2014, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and the other lenders party thereto.	8-K	000-19514	10.1	4/28/2014
10.16	Second Amendment to Amended and Restated Credit Agreement, dated as of November 26, 2014, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto.	8-K	000-19514	10.1	12/3/2014
10.17	Third Amendment to Amended and Restated Credit Agreement, dated as of April 10, 2015, among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto.	8-K	000-19514	10.1	4/15/2015
10.18	Fourth Amendment to Amended and Restated Credit Agreement, dated as of May 29, 2015, among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, and the lenders party thereto.	10-Q	000-19514	10.2	8/7/2015
10.19	Fifth Amendment to Amended and Restated Credit Agreement, dated as of September 18, 2015, among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto.	8-K	000-19514	10.1	9/24/2015
10.20	Sixth Amendment, dated February 19, 2016, to Amended and Restated Credit Agreement, dated as of September 18, 2015, among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto.	10-Q	000-19514	10.2	5/5/2016
10.21	Seventh Amendment to Amended and Restated Credit Agreement, dated as of December 13, 2016, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto.	8-K	000-19514	10.1	12/15/2016
10.22	Eighth Amendment to Amended and Restated Credit Agreement, entered into as of March 29, 2017, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent and L/C issuer, and the lenders party thereto.	8-K	000-19514	10.1	4/4/2017
10.23	Ninth Amendment to Amended and Restated Credit Agreement, entered into as of May 4, 2017, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent and L/C issuer, the existing lenders named therein and JPMorgan Chase Bank, N.A., Commonwealth Bank of Australia, ABN, AMRO Capital USA LLC, Fifth Third Bank and Canadian Imperial Bank of Commerce, New York branch, as new lenders.	10-Q	000-19514	10.2	5/9/2017

10.24	Tenth Amendment to Amended and Restated Credit Agreement, dated as of October 4, 2017, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto.	8-K	000-19514	10.1	10/5/2017
10.25	Eleventh Amendment to Amended and Restated Credit Agreement, dated as of November 21, 2017, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto.	8-K	000-19514	10.1	11/28/2017
10.26	Twelfth Amendment to Amended and Restated Credit Agreement, dated as of May 21, 2018, among Gulfport Energy Corporation, as borrower, The Bank of Nova Scotia, as administrative agent, and the lenders party thereto.	8-K	000-19514	10.1	5/25/2018
10.27	Thirteenth Amendment to the Amended and Restated Credit Agreement, dated as of November 28, 2018, between Gulfport Energy Corporation, as Borrower, The Bank of Nova Scotia, as Administrative Agent and the lenders party thereto.	8-K	000-19514	10.1	12/4/2018
10.28	Fourteenth Amendment to the Amended and Restated Credit Agreement, dated as of June 3, 2019, between Gulfport Energy Corporation, as Borrower, The Bank of Nova Scotia, as Administrative Agent and the lenders party thereto.	8-K	000-19514	10.1	6/7/2019
10.29	Fifteenth Amendment to the Amended and Restated Credit Agreement, dated as of May 1, 2020, between Gulfport Energy Corporation, as Borrower, the Bank of Nova Scotia, as Administrative Agent and the lenders party thereto.	10-Q	001-19514	10.3	8/7/2020
10.30	Sixteenth Amendment to the Amended and Restated Credit Agreement, dated as of July 27, 2020, between Gulfport Energy Corporation, as Borrower, the Bank of Nova Scotia, as Administrative Agent and the lenders party thereto	8-K	001-19514	10.1	7/30/2020
10.31	First Forbearance Agreement and Amendment to Amended and Restated Credit Agreement, dated as of October 15, 2020, by and among the Gulfport Energy Corporation, as Borrower, the Bank of Nova Scotia, as Administrative Agent and the lender party thereto.	8-K	001-19514	10.1	10/16/2020
10.32	Second Forbearance Agreement and Amendment to Amended and Restated Credit Agreement, dated as of October 26, 2020, by and among the Gulfport Energy Corporation, as Borrower, the Bank of Nova Scotia, as Administrative Agent and the lender party thereto.	8-K	001-19514	10.1	10/29/2020
10.33	Restructuring Support Agreement, dated November 13, 2020.	8-K	001-19514	10.2	11/16/2020
10.34	Backstop Commitment Agreement, dated November 13, 2020 (incorporated by reference to Exhibit D of the Restructuring Support Agreement attached as Exhibit 10.33 hereto).	8-K	001-19514	10.2	11/16/2020

10.35	Form of DIP Credit Agreement (incorporated by reference to Exhibit E of the Restructuring Support Agreement attached as Exhibit 10.33 hereto).	8-K	001-19514	10.4	11/16/2020	
10.36	Senior Secured Super Priority Debtor-in-Possession Credit Agreement, dated as of November 17, 2020, by and among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, and the other lenders party thereto.	8-K	001-19514	10.1	11/20/2020	
10.37#	Sand Supply Agreement, effective as of October 1, 2014, by and between Muskie Proppant LLC and Gulfport Energy Corporation.	10-Q	000-19514	10.1	11/7/2014	
10.38#	Amendment to Sand Supply Agreement, dated as of November 3, 2015, by and between Muskie Proppant LLC and Gulfport Energy Corporation.	10-Q	000-19514	10.2	11/5/2015	
10.39	Second Amendment to Sand Supply Agreement, dated as of August 6, 2018, between Gulfport Energy Corporation and Muskie Proppant LLC.	10-Q	000-19514	10.2	11/1/2018	
10.40#	Amended and Restated Master Services Agreement, effective as of October 1, 2014, by and between Gulfport Energy Corporation and Stingray Pressure Pumping LLC.	10-Q	000-19514	10.2	11/7/2014	
10.41#	Amendment to Amended and Restated Master Services Agreement, dated as of February 18, 2016 to be effective as of January 1, 2016, by and between Gulfport Energy Corporation and Stingray Pressure Pumping LLC.	10-K	000-19514	10.19	2/19/2016	
10.42#	Amendment No. 2, dated as of July 10, 2018, between Stingray Pressure Pumping, LLC and Gulfport Energy Corporation to that certain Amended & Restated Master Services Agreement for Pressure Pumping Services, effective as of October 1, 2014, as amended effective January 1, 2016.	10-Q	000-19514	10.2	8/2/2018	
10.43+	Form of Indemnification Agreement.	S-4	333-199905	10.1	11/6/2014	
14	Code of Ethics.	8-K	000-19514	14	2/14/2006	
21	Subsidiaries of the Registrant.					X
23.1	Consent of Grant Thornton LLP.					X
23.2	Consent of Netherland, Sewell & Associates, Inc.					X
31.1	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.					X
31.2	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.					X

32.1	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.	X
32.2	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.	X
99.1	Report of Netherland, Sewell & Associates, Inc.	X
101.INS	Inline XBRL Instance Document.	X
11.SCH*	Inline XBRL Taxonomy Extension Schema Document.	X
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.	X
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.	X
101.LAB	Inline XBRL Taxonomy Extension Labels Linkbase Document.	X
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.	X

* Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The registrant hereby undertakes to furnish supplemental copies of any of the omitted schedules upon request by the SEC.

** The Company agrees to furnish a copy of any of its unfiled long-term debt instruments to the Securities and Exchange Commission upon request.

\+ Management contract, compensatory plan or arrangement.

\# Confidential treatment has been requested for portions of this exhibit. These portions have been omitted and submitted separately to the Securities and Exchange Commission.

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: March 5, 2021

GULFPORT ENERGY CORPORATION

By: /s/ QUENTIN HICKS

Quentin Hicks
Chief Financial Officer

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date:	March 5, 2021	By:	/s/ DAVID M. WOOD **David M. Wood** **Chief Executive Officer and President, Director** **(Principal Executive Officer)**
Date:	March 5, 2021	By:	/s/ ALVIN BLEDSOE **Alvin Bledsoe** **Chairman of the Board and Director**
Date:	March 5, 2021	By:	/s/ QUENTIN HICKS **Quentin Hicks** **Chief Financial Officer** **(Principal Accounting and Financial Officer)**
Date:	March 5, 2021	By:	/s/ DEBORAH G. ADAMS **Deborah G. Adams** **Director**
Date:	March 5, 2021	By:	/s/ SAMANTHA HOLROYD **Samantha Holroyd** **Director**
Date:	March 5, 2021	By:	/s/ VALERIE JOCHEN **Valerie Jochen** **Director**
Date:	March 5, 2021	By:	/s/ C. DOUG JOHNSON **C. Doug Johnson** **Director**
Date:	March 5, 2021	By:	/s/ BEN T. MORRIS **Ben T. Morris** **Director**
Date:	March 5, 2021	By:	/s/ JOHN W. SOMERHALDER II **John W. Somerhalder II** **Director**

Exhibit 21

SUBSIDIARIES OF GULFPORT ENERGY CORPORATION

Name of Subsidiary	**Jurisdiction of Organization**
Grizzly Holdings, Inc.	Delaware
Jaguar Resources LLC	Delaware
Puma Resources, Inc.	Delaware
Gator Marine, Inc.	Delaware
Gator Marine Ivanhoe, Inc.	Delaware
Westhawk Minerals LLC	Delaware
Gulfport Appalachia, LLC (formerly known as Gulfport Buckeye LLC)	Delaware
Gulfport Midstream Holdings, LLC	Delaware
Gulfport MidCon, LLC	Delaware
Mule Sky LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 5, 2021, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Gulfport Energy Corporation on Form 10-K for the year ended December 31, 2020. We consent to the incorporation by reference of said reports in the Registration Statements of Gulfport Energy Corporation on Forms S-8 (File No. 333-206564, effective August 25, 2015; File No. 333-135728, effective July 12, 2006; File No. 333-129178, effective October 21, 2005; and File No. 333-55738, effective February 16, 2001).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 5, 2021

NETHERLAND, SEWELL & ASSOCIATES, INC.

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the inclusion in the Form 10-K of Gulfport Energy Corporation (the "Form 10-K") of our report dated February 5, 2021 on oil and gas reserves of Gulfport Energy Corporation and its subsidiaries as of December 31, 2020, located in the United States and information from our prior reserve reports referenced in the Form 10-K, to all references to our firm included in the Form 10-K and to the incorporation by reference of such reports in the Registration Statements of Gulfport Energy Corporation on Form S-8 (File No. 333-206564, effective August 25, 2015; File No. 333-135728, effective July 12, 2006; File No. 333-129178, effective October 21, 2005; and File No. 333-55738, effective February 16, 2001) and on Form S-3ASR (File No. 33-215078, automatically effective December 14, 2016, and File No. 333-217362, automatically effective April 18, 2017).

NETHERLAND, SEWELL & ASSOCIATES, INC.

/s/ Richard B. Talley, Jr.
By:
Richard B. Talley, Jr., P.E.
Senior Vice President

Houston, Texas
March 5, 2021

Exhibit 31.1

CERTIFICATION

I, David M. Wood, Chief Executive Officer of Gulfport Energy Corporation, certify that:

1. I have reviewed this Annual Report on Form 10-K of Gulfport Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statement made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in the Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information;

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: March 5, 2021

/s/ David M. Wood
David M. Wood
Chief Executive Officer and President

Exhibit 31.2

CERTIFICATION

I, Quentin Hicks, Chief Financial Officer of Gulfport Energy Corporation, certify that:

1. I have reviewed this Annual Report on Form 10-K of Gulfport Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statement made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in the Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information;

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: March 5, 2021

/s/ Quentin Hicks
Quentin Hicks
Chief Financial Officer

Exhibit 32.1

CERTIFICATION OF PERIODIC REPORT

I, David M. Wood, Chief Executive Officer of Gulfport Energy Corporation (the “Company”), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2020 (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 5, 2021

/s/ David M. Wood
David M. Wood
Chief Executive Officer and President

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION OF PERIODIC REPORT

I, Quentin Hicks, Chief Financial Officer of Gulfport Energy Corporation (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2020 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 5, 2021

/s/ Quentin Hicks
Quentin Hicks
Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

February 5, 2021

Mr. David M. Wood
Gulfport Energy Corporation
3001 Quail Springs Parkway
Oklahoma City, Oklahoma 73134

Dear Mr. Wood:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2020, to the Gulfport Energy Corporation (Gulfport) interest (both direct and indirect) in certain oil and gas properties located in the United States. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Gulfport. Reserves have been included for locations in the proved undeveloped category based on Gulfport's reasonable expectation that it will emerge from bankruptcy with available financing to implement the development plan for these locations. This expectation is supported by the current bankruptcy plan submitted to the court and the anticipated approval of that plan. It is our understanding that this plan reduces Gulfport's debt and provides access to adequate funding to meet the required capital budget. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Gulfport's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Gulfport interest in these properties, as of December 31, 2020, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	6,637.2	21,478.4	1,338,969.3	672,963.8	498,734.8
Proved Developed Non-Producing	0.0	103.9	19,031.0	6,411.3	4,980.3
Proved Undeveloped	6,846.7	16,052.2	923,207.3	284,903.3	36,283.7
Total Proved	13,483.8	37,634.5	2,281,207.8	964,278.6	539,998.8

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. Estimates of proved undeveloped reserves have been included for certain locations that generate positive future net revenue but have negative present worth discounted at 10 percent based on the constant price and cost parameters discussed in subsequent paragraphs of this letter. These locations have been included based on the operators' declared intent to drill these wells, as evidenced by Gulfport's internal budget, reserves estimates, and price forecast. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is Gulfport's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Gulfport's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2020. For oil and NGL volumes, the average West Texas Intermediate spot price of $39.54 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $1.985 per MMBTU is adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $34.44 per barrel of oil, $15.35 per barrel of NGL, and $1.331 per MCF of gas.

Operating costs used in this report are based on operating expense records of Gulfport. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs and per-unit-of-production costs. The fees associated with Gulfport's transportation contracts are included as additional operating expenses. Headquarters general and administrative overhead expenses of Gulfport are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Gulfport and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Gulfport's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Gulfport interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Gulfport receiving its net revenue interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Gulfport, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Gulfport, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. Richard B. Talley, Jr., a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2004 and has over 5 years of prior industry experience. Edward C. Roy III, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2008 and has over 11 years of prior industry experience. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III
By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

/s/ Richard B. Talley, Jr.	/s/ Edward C. Roy III
By:	By:
Richard B. Talley, Jr., P.E. 102425	Edward C. Roy III, P.G. 2364
Senior Vice President	Vice President
Date Signed: February 5, 2021	Date Signed: February 5, 2021

RBT:SAO

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs*. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.
(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(i) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, 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—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

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

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

- *(a) Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
- *(b) Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

- *(a) Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
- *(b) Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
- *(c) Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
- *(d) Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
- *(e) Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
- *(f) Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category 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.

- (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

> From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):
>
> Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.
>
> Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:
>
> - The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);
> - The company's historical record at completing development of comparable long-term projects;
> - The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;
> - The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and
> - The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.