UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2020
or
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission file number: 001-35380

Laredo Petroleum, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**45-3007926**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

15 W. Sixth Street	**Suite 900**	
Tulsa	**Oklahoma**	**74119**
(Address of principal executive offices)		(Zip code)

(918) 513-4570

(Registrant's telephone number, including area code)
Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Trading symbol	Name of each exchange on which registered
Common stock, $0.01 par value per share	LPI	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: **None**

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 (§ 232.405 of this chapter) during the preceding 12 months (or for 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 the 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 for 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 ☒

Aggregate market value of the voting and non-voting common equity held by non-affiliates was approximately $126.4 million on June 30, 2020, based on $13.86 per share, the last reported sales price of the common stock on the New York Stock Exchange on such date.

Number of shares of registrant's common stock outstanding as of February 15, 2021: 12,019,176

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2021 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2020, are incorporated by reference into Part III of this report for the year ended December 31, 2020.

Table of Contents

Glossary of Oil and Natural Gas Terms

The following terms are used throughout this Annual Report on Form 10-K (this "Annual Report"):

"*2D*"—Method for collecting, processing and interpreting seismic data in two dimensions.

"*3D*"—Method for collecting, processing and interpreting seismic data in three dimensions.

"*Allocation well*"—A horizontal well drilled by an oil and gas producer under two or more leaseholds that are not pooled, under a permit issued by the Texas Railroad Commission.

"*Basin*"—A large natural depression on the earth's surface in which sediments, generally brought by water, accumulate.

"*Bbl*" or "*barrel*"—One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate, natural gas liquids or water.

"*Benchmark Prices*"—The unweighted arithmetic average first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period before differentials, as required by SEC guidelines.

"*BOE*"—One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.

"*BOE/D*"—BOE per day.

"Brent"—A light (low density) and sweet (low sulfur) crude oil sourced from the North Sea, used as a pricing benchmark for ICE oil futures contracts.

"*Btu*"—British thermal unit, the quantity of heat required to raise the temperature of a one pound mass of water by one degree Fahrenheit.

"*Completion*"—The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"*Developed acreage*"—The number of acres that are allocated or assignable to productive wells or wells capable of production.

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

"*Dry hole*"—A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"*Exploratory well*"—A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

"*Field*"—An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"*Formation*"—A layer of rock which has distinct characteristics that differ from nearby rock.

"*Fracturing*" or "*Frac*"—The propagation of fractures in a rock layer by a pressurized fluid. This technique is used to release petroleum and natural gas for extraction.

"*GAAP*"—Generally accepted accounting principles in the United States.

"*Gross acres*" or "*gross wells*"—The total acres or wells, as the case may be, in which a working interest is owned.

"*HBP*"—Acreage that is held by production.

"Henry Hub"—A natural gas pipeline delivery point in south Louisiana that serves as the benchmark natural gas price underlying NYMEX natural gas futures contracts.

"*Horizon*"—A term used to denote a surface in or of rock, or a distinctive layer of rock that might be represented by a reflection in seismic data.

"*Horizontal drilling*"—A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"ICE"—The Intercontinental Exchange.

"*Initial Production*"—The measurement of production from an oil or gas well when first brought on stream. Often stated in terms of production during the first thirty days.

"*Liquids*"—Describes oil, condensate and natural gas liquids.

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

"*MBOE*"—One thousand BOE.

"*MMBOE*"—One million BOE.

"*Mcf*"—One thousand cubic feet of natural gas.

"*MMBtu*"—One million Btu.

"*MMcf*"—One million cubic feet of natural gas.

"*Natural gas liquids*" or "*NGL*"—Components of natural gas that are separated from the gas state in the form of liquids, which include propane, butanes and ethane, among others.

"*Net acres*"—The percentage of gross acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

"*NYMEX*"—The New York Mercantile Exchange.

"*Productive well*"—A well that is 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 non-producing reserves*" or "*PDNP*"—Developed non-producing reserves.

"*Proved developed reserves*" or "*PDP*"—Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"*Proved reserves*"—The estimated quantities of oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

"*Proved undeveloped reserves*" or "*PUD*"—Proved reserves that are expected to be recovered within five years from new wells on undrilled locations and for which a specific capital commitment has been made or from existing wells where a relatively major expenditure is required for recompletion.

"*Realized Prices*"—Prices which reflect adjustments to the Benchmark Prices for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the delivery point without giving effect to our commodity derivative transactions.

"*Recompletion*"—The process of re-entering an existing wellbore that is either producing or not producing and completing in new reservoirs in an attempt to establish or increase existing production.

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

"*Spacing*"—The distance between wells producing from the same reservoir.

"*Standardized measure*"—Discounted future net cash flows estimated by applying Realized Prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

"*Three stream*"—Production or reserve volumes of oil, natural gas liquids and natural gas, where the natural gas liquids have been removed from the natural gas stream and the economic value of the natural gas liquids is separated from the wellhead natural gas price.

"*Undeveloped acreage*"—Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

"*Wellhead natural gas*"—Natural gas produced at or near the well.

"*Wolfberry*"—A general industry term that applies to the vertical stratigraphic interval that can include the shallow Spraberry formation to the deeper Woodford formation throughout the Permian Basin.

"*Working interest*" or "*WI*"—The right granted to the lessee of a property to explore for and to produce and own crude oil, natural gas liquids, natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis.

"*WTI*"—West Texas Intermediate grade crude oil. A light (low density) and sweet (low sulfur) crude oil, used as a pricing benchmark for NYMEX oil futures contracts.

Cautionary Statement Regarding Forward-Looking Statements

Various statements contained in or incorporated by reference into this Annual Report are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These forward-looking statements include statements, projections and estimates concerning our operations, performance, business strategy, oil, NGL and natural gas reserves, drilling program capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "will," "foresee," "plan," "goal," "should," "intend," "pursue," "target," "continue," "suggest" or the negative thereof or other variations thereof or other words that convey the uncertainty of future events or outcomes. Forward-looking statements are not guarantees of performance. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Among the factors that significantly impact our business and could impact our business in the future are:

- the effects, duration, government response or other implications of the outbreak and continued spread of the coronavirus ("COVID-19"), or the threat and occurrence of other epidemic or pandemic diseases;
- changes in domestic and global production, supply and demand for oil, NGL and natural gas, including the decrease in demand and oversupply of oil and natural gas as a result of the COVID-19 pandemic and actions by the Organization of the Petroleum Exporting Countries members and other oil exporting nations ("OPEC+");
- the volatility of oil, NGL and natural gas prices, including in our area of operation in the Permian Basin;
- the potential impact of suspending drilling programs and completions activities or shutting in a portion of our wells, as well as costs to later restart, and co-development considerations such as horizontal spacing, vertical spacing and parent-child interactions on production of oil, NGL and natural gas from our wells;
- United States ("U.S.") and international economic conditions and legal, tax, political and administrative developments, including the effects of the recent U.S. presidential, congressional and state elections on energy, trade and environmental policies and existing and future laws and government regulations;
- our ability to comply with federal, state and local regulatory requirements;
- the ongoing instability and uncertainty in the U.S. and international energy, financial and consumer markets that could adversely affect the liquidity available to us and our customers and the demand for commodities, including oil, NGL and natural gas;
- our ability to execute our strategies, including our ability to successfully identify and consummate strategic acquisitions at purchase prices that are accretive to our financial results and to successfully integrate acquired businesses, assets and properties;
- competition in the oil and natural gas industry;
- our ability to discover, estimate, develop and replace oil, NGL and natural gas reserves and inventory;
- drilling and operating risks, including risks related to hydraulic fracturing activities and those related to inclement or extreme weather, impacting our ability to produce existing wells and/or drill and complete new wells over an extended period of time;
- the long-term performance of wells that were completed using different technologies;
- revisions to our reserve estimates as a result of changes in commodity prices, decline curves and other uncertainties;
- impacts of impairment write-downs on our financial statements;

- capital requirements for our operations and projects;
- our ability to continue to maintain the borrowing capacity under our Fifth Amended and Restated Credit Agreement (as amended, the "Senior Secured Credit Facility") or access other means of obtaining capital and liquidity, especially during periods of sustained low commodity prices;
- our ability to comply with restrictions contained in our debt agreements, including our Senior Secured Credit Facility and the indentures governing our senior unsecured notes, as well as debt that could be incurred in the future;
- our ability to generate sufficient cash to service our indebtedness, fund our capital requirements and generate future profits;
- our ability to hedge, and regulations that affect our ability to hedge;
- the availability and costs of drilling and production equipment, supplies, labor and oil and natural gas processing and other services;
- the availability and costs of sufficient gathering, processing, storage and export capacity in the Permian Basin and refining capacity in the U.S. Gulf Coast;
- the impact of repurchases, if any, of securities from time to time;
- the effectiveness of our internal controls over financial reporting and our ability to remediate a material weakness in our internal controls over financial reporting;
- our ability to maintain the health and safety of, as well as recruit and retain, qualified personnel necessary to operate our business;
- risks related to the geographic concentration of our assets; and
- our ability to secure or generate sufficient electricity to produce our wells without limitations.

These forward-looking statements involve a number of risks and uncertainties that could cause actual results to differ materially from those suggested by the forward-looking statements. Forward-looking statements should therefore be considered in light of various factors, including those set forth in this Annual Report under "Item 1A. Risk Factors," in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Annual Report. In light of such risks and uncertainties, we caution you not to place undue reliance on these forward-looking statements. These forward-looking statements speak only as of the date of this Annual Report, or if earlier, as of the date they were made. We do not intend to, and disclaim any obligation to, update or revise any forward-looking statements unless required by securities law.

Part I

Item 1. Business

Laredo Petroleum, Inc. is a Delaware corporation formed in 2011 for the purpose of merging with Laredo Petroleum, LLC (a Delaware limited liability company formed in 2007) to consummate an initial public offering of common stock in December 2011 ("IPO"). Laredo Petroleum, Inc. was the survivor of such merger and currently has two wholly-owned subsidiaries, Laredo Midstream Services, LLC, a Delaware limited liability company ("LMS"), and Garden City Minerals, LLC, a Delaware limited liability company ("GCM").

Except where the context indicates otherwise, amounts, numbers, dollars and percentages presented in this Annual Report are rounded and therefore approximate. Unless the context otherwise requires, references in this Annual Report to "Laredo," the "Company," "we," "our," "us," or similar terms refer to Laredo Petroleum, Inc. and its subsidiaries at the applicable time, including former subsidiaries and predecessor companies, as applicable. For a full discussion of the development of our business, as well as our business strategy and competitive strengths, see "Part I, Item 1. Business" in our 2019 Annual Report on Form 10-K.

Overview

Laredo is an independent energy company focused on the acquisition, exploration and development of oil and natural gas properties, primarily in the Permian Basin of West Texas. The oil and liquids-rich Permian Basin is characterized by multiple target horizons, extensive production histories, long-lived reserves, high drilling success rates and high initial production rates. As of December 31, 2020, we had assembled 133,199 net acres in the Permian Basin, all of which were held in 290 sections. Our acreage is largely contiguous in the neighboring Texas counties of Howard, Glasscock, Reagan, Sterling and Irion. We have identified one operating segment: exploration and production.

Business Strategy and 2020 Operational Highlights

Our strategy is to create stakeholder value through the development of our Permian Basin acreage. We do this by optimizing our assets, managing our risk and seeking to acquire additional high-margin inventory.

We optimize our assets and achieve attractive rates of return on our capital deployed through a combination of (i) maintaining one of the lowest drilling and completions and operating cost structures in the Permian Basin, (ii) conservative well-spacing that seeks to balance location count and well productivity and (iii) strategic investments in midstream infrastructure. Key to our low costs are (i) the contiguous nature of our acreage which enables us to drill longer more capital efficient lateral wells, (ii) our high working interests and extensive interests in leases held by production that provide us the operational control necessary to enhance our returns through operational and cost efficiencies and (iii) the infrastructure in place in both our legacy acreage and more recently acquired acreage either owned by us or built around us by third-parties.

Throughout 2020, we transitioned our development program to our acreage positions in Howard and Glasscock counties that were assembled in separate transactions in the fourth quarter of 2019 and throughout 2020 totaling approximately 16,000 net acres. This move optimizes our capital investments by putting our low cost structure to work on our oiliest acreage to produce the highest rate of return. Commencing in March 2020, in response to the COVID-19 pandemic and the resulting fall in commodity prices, we slowed our operating cadence for a portion of the year. As commodity prices improved and drilling and completions costs decreased, improving expected returns on development capital, we returned to a consistent development pace at the end of 2020 and into 2021.

Our operational execution continued to exceed expectations during 2020, despite the dual challenges of a worldwide pandemic and a full transition of our drilling and completions operations to new areas of our leasehold. We maintained our drilling and completions efficiencies in our move to Glasscock and Howard counties, lowering drilling and completion costs 21% from levels at the end of 2019. Additionally, we reduced unit lease operating expenses ("LOE") 17% versus full-year 2019 and reduced unit general and administrative expenses ("G&A"), excluding long-term incentive plan expenses ("LTIP"), by 21% versus full-year 2019.

We proactively managed our risk in 2020 by pushing out our near-term debt maturities. Early in the year, we issued two series of senior unsecured notes and used the proceeds therefrom to, among other things, repay our then outstanding senior

unsecured notes. As a result, the maturity dates on our long-term debt were extended to 2025 and 2028. We believe that this extension provides us with financial flexibility to execute on our strategy. Additionally, we have historically hedged our production to protect cash flows and diminish the effects of commodity price fluctuations. During 2020, our hedging program provided us with approximately $234 million of cash flow. In addition to the hedges entered into in 2020, we will continue to seek hedging opportunities on a multi-year basis to further protect our cash flows.

Finally, we continued to expand our high-margin acreage in Howard and Glasscock counties in 2020. We intend to continue our efforts to add more of this type of acreage as we seek to increase oil as a percentage of our production and improve our margins and profitability as we take advantage of our low cost structure on more productive acreage. We are highly selective in the projects that we consider and we will continue to monitor the market for strategic opportunities that we believe could be accretive and enhance shareholder value. These opportunities may take the form of acquisitions, divestitures, mergers, redemptions, equity or debt repurchases, delevering or other similar transactions, any of which could result in the utilization of our Senior Secured Credit Facility and/or further accessing the capital markets.

Operating Areas

We focus our exploration, development and production efforts in one geographic operating area, the Permian Basin.

Well Data

We are currently focusing our development activities on horizontal drilling targets in the Upper Wolfcamp, Middle Wolfcamp and Lower Spraberry formations. Other formations for possible future development include the Upper Spraberry, Middle Spraberry, Lower Wolfcamp, Cline and Canyon. From our inception in 2006 through December 31, 2020, we have drilled and completed (i.e., the particular well is producing) 421 horizontal wells in the Upper and Middle Wolfcamp and Lower Spraberry and 967 vertical wells in the Wolfberry interval. Of these 421 horizontal wells, 221 were horizontal Upper Wolfcamp wells, 192 were horizontal Middle Wolfcamp wells and 8 were Lower Spraberry. We have also drilled and completed 33 horizontal Lower Wolfcamp wells, 66 horizontal Cline wells and one vertical Ellenberger saltwater disposal well. As of December 31, 2020, we had an average working interest of 97% in Laredo-operated active productive wells and 93% in all wells in which Laredo has an interest, and our leases are 88% held by production.

The following table sets forth certain information regarding productive wells as of December 31, 2020. All but three of our wells are classified as oil wells, all of which also produce liquids-rich natural gas and condensate. Wells are classified as oil or natural gas wells according to the predominant production stream. We also own royalty and overriding royalty interests in a small number of wells in which we do not own a working interest.

	Total producing wells				
	Gross			Net	
	Vertical	Horizontal	Total	Total	Average WI %
Permian-Midland Basin:					
Operated	795	527	1,322	1,286	97 %
Non-operated	59	16	75	16	21 %
Total	854	543	1,397	1,302	93 %

Drilling Activity

On December 31, 2020, we had one drilling rig drilling horizontal wells. We anticipate utilizing two horizontal drilling rigs during 2021. We do not anticipate utilizing any vertical drilling rigs in 2021. If we decrease our drilling rig count and/or completion crews, it will have a negative impact on our production. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Obligations and commitments" and Note 16.b to our consolidated financial statements included elsewhere in this Annual Report for additional information.

Table of Contents

The following table summarizes our drilling activity with respect to the number of wells completed for the periods presented. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells.

	Years ended December 31,					
	2020		2019		2018	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	48	47.3	59	56.2	74	71.2
Dry	—	—	—	—	—	—
Total development wells	48	47.3	59	56.2	74	71.2
Exploratory wells:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total exploratory wells	—	—	—	—	—	—

Sales volumes, revenues, prices and expenses history

The following table presents information regarding our oil, NGL and natural gas sales volumes, sales revenues, average sales prices, and selected average costs and expenses per BOE sold for the periods presented and corresponding changes. Our reserves and sales volumes are reported in three streams: crude oil, NGL and natural gas. For additional information on price calculations, see the information in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

(unaudited)	Years ended December 31, 2020	2019	2018	2020 compared to 2019 Change (#)	Change (%)
Sales volumes:					
Oil (MBbl)	9,827	10,376	10,175	(549)	(5)%
NGL (MBbl)	10,615	9,118	7,259	1,497	16 %
Natural gas (MMcf)	70,049	60,169	44,680	9,880	16 %
Oil equivalents (MBOE)[(1)(2)]	32,117	29,522	24,881	2,595	9 %
Average daily oil equivalent sales volumes (BOE/D)[(2)]	87,750	80,883	68,168	6,867	8 %
Average daily oil sales volumes (Bbl/D)[(2)]	26,849	28,429	27,878	(1,580)	(6)%
Sales revenues (in thousands):					
Oil	$ 367,792	$ 572,918	$ 605,197	$(205,126)	(36)%
NGL	$ 78,246	$ 100,330	$ 149,843	$ (22,084)	(22)%
Natural gas	$ 50,317	$ 33,300	$ 53,490	$ 17,017	51 %
Average sales prices[(2)]:					
Oil ($/Bbl)[(3)]	$ 37.43	$ 55.21	$ 59.48	$ (17.78)	(32)%
NGL ($/Bbl)[(3)]	$ 7.37	$ 11.00	$ 20.64	$ (3.63)	(33)%
Natural gas ($/Mcf)[(3)]	$ 0.72	$ 0.55	$ 1.20	$ 0.17	31 %
Average sales price ($/BOE)[(3)]	$ 15.45	$ 23.93	$ 32.50	$ (8.48)	(35)%
Oil, with commodity derivatives ($/Bbl)[(4)]	$ 56.41	$ 54.37	$ 55.49	$ 2.04	4 %
NGL, with commodity derivatives ($/Bbl)[(4)]	$ 9.12	$ 13.61	$ 20.03	$ (4.49)	(33)%
Natural gas, with commodity derivatives ($/Mcf)[(4)]	$ 1.02	$ 1.05	$ 1.77	$ (0.03)	(3)%
Average sales price, with commodity derivatives ($/BOE)[(4)]	$ 22.50	$ 25.45	$ 31.72	$ (2.95)	(12)%
Selected average costs and expenses per BOE sold[(1)(2)]					
Lease operating expenses	$ 2.55	$ 3.08	$ 3.67	$ (0.53)	(17)%
Production and ad valorem taxes	1.03	1.38	1.99	(0.35)	(25)%
Transportation and marketing expenses	1.55	0.86	0.47	0.69	80 %
Midstream service expenses	0.12	0.15	0.12	(0.03)	(20)%
General and administrative (excluding LTIP)	1.29	1.63	2.51	(0.34)	(21)%
Total selected operating expenses	$ 6.54	$ 7.10	$ 8.76	$ (0.56)	(8)%
General and administrative (LTIP):					
LTIP cash	$ 0.06	$ —	$ —	$ 0.06	100 %
LTIP non-cash	$ 0.22	$ 0.22	$ 1.35	$ —	— %
Depletion, depreciation and amortization	$ 6.76	$ 9.00	$ 8.55	$ (2.24)	(25)%

(1) BOE is calculated using a conversion rate of six Mcf per one Bbl.

(2) The numbers presented in the years ended December 31, 2020, 2019 and 2018 columns are based on actual amounts and are not calculated using the rounded numbers presented in the table above.

(3) Price reflects the average of actual sales prices received when control passes to the purchaser/customer adjusted for quality, certain transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the delivery point.

(4) Price reflects the after-effects of our commodity derivative transactions on our average sales prices. Our calculation of such after-effects includes settlements of matured commodity derivatives during the respective periods in accordance with GAAP and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to commodity derivatives that settled during the respective periods.

Reserves

In this Annual Report, the information with respect to our estimated proved reserves has been prepared by Ryder Scott Company, L.P. ("Ryder Scott"), our independent reserve engineers, in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") applicable to the reporting dates presented.

The following table summarizes our total estimated net proved reserves presented on a three-stream basis, net acreage and producing wells as of the date presented, and net average daily production presented on a three-stream basis for the period presented.

	December 31, 2020					Year ended December 31, 2020			
	Estimated proved reserves[(1)]			Producing wells		Average daily production			
	MBOE	% Oil	Net acreage	Gross	Net	(BOE/D)	% Oil	% NGL	% Natural gas
Permian-Midland Basin	278,228	24 %	133,199	1,397	1,302	87,750	31 %	33 %	36 %

(1) See "—Our operations—Estimated proved reserves" for discussion of the prices utilized to estimate our reserves.

Our estimated proved reserves as of December 31, 2020 assume our ability to fund the capital costs necessary for their development and are affected by pricing assumptions. See Note 6.a to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our Realized Prices. See "Item 1A. Risk Factors—Risks related to our business—Estimating reserves and future net cash flows involves uncertainties. Negative revisions to reserve estimates, decreases in oil, NGL and natural gas prices or increases in service costs, may lead to decreased earnings and increased losses or impairment of oil and natural gas properties. The following table sets forth additional information regarding our estimated proved reserves as of the dates presented:

	December 31, 2020	December 31, 2019
Proved developed:		
Oil (MBbl)	51,751	52,711
NGL (MBbl)	96,251	90,861
Natural gas (MMcf)	633,503	600,334
Total proved developed (MBOE)	253,586	243,628
Proved undeveloped:		
Oil (MBbl)	16,008	25,928
NGL (MBbl)	4,671	11,337
Natural gas (MMcf)	23,781	74,903
Total proved undeveloped (MBOE)	24,642	49,749
Estimated proved reserves:		
Oil (MBbl)	67,759	78,639
NGL (MBbl)	100,922	102,198
Natural gas (MMcf)	657,284	675,237
Total estimated proved reserves (MBOE)	278,228	293,377
Percent developed	91 %	83 %

Technology used to establish proved reserves

Under SEC rules, proved reserves are those quantities of oil, NGL and natural gas that 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. Reasonable certainty implies a high degree of confidence that the quantities of oil, NGL and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that

establishes reasonable certainty. 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.

To establish reasonable certainty with respect to our estimated proved reserves, our internal reserve engineers and Ryder Scott, our independent reserve engineers, employed reliable technologies that have been demonstrated to yield results with consistency and repeatability.

Qualifications of technical persons and internal controls over reserves estimation process

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 Reserves Auditing Standards") and guidelines established by the SEC, Ryder Scott, our independent reserve engineers, estimated 100% of our proved reserve information as of December 31, 2020, 2019 and 2018 included in this Annual Report. The technical persons responsible for preparing the reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the SPE Reserves Auditing Standards.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to Ryder Scott in their reserves estimation process. Our technical team meets regularly with representatives of Ryder Scott to review properties and discuss methods and assumptions used in Ryder Scott's preparation of the year-end reserve estimates. The Ryder Scott reserve report is reviewed with representatives of Ryder Scott and our internal technical staff before dissemination of the information.

Our Vice President of Planning and Business Development is the technical person primarily responsible for overseeing the preparation of our reserve estimates. He has more than 30 years of practical experience, with 29 years of this experience being in the estimation and evaluation of reserves. He has a Bachelors and Masters of Science in Petroleum Engineering from Texas A&M University. Our Vice President of Planning and Business Development reports to our Chief Financial Officer. Reserve estimates are reviewed and approved by our senior engineering staff, other members of senior management and our technical staff, our audit committee and our Chief Executive Officer.

Proved undeveloped reserves

In order to maximize operational flexibility through the commodity price declines, we limit the portion of reserves categorized as "proved undeveloped" or "PUD" to approximately two years of activity. This is shorter than the five years allowed by SEC rules, but allows us to emphasize operations on our most economic investments and maintain conservative assurance that all PUD locations will be converted despite potential commodity price volatility.

Our proved undeveloped reserves decreased from 49,749 MBOE as of December 31, 2019 to 24,642 MBOE as of December 31, 2020. We estimate that we incurred $230 million of costs to convert 23,491 MBOE of proved undeveloped reserves from 42 locations into proved developed reserves in 2020. New proved undeveloped reserves of 9,753 MBOE were added during the year from (i) 5,808 MBOE from 7 Spraberry and 10 new Wolfcamp locations along with (ii) 3,945 MBOE from additional acreage acquired under proved locations in Howard County. 11,369 MBOE of negative revisions consisted of (i) 8,245 MBOE of negative revisions due to proved undeveloped locations that were removed due to year-end pricing and (ii) 3,124 MBOE of negative revisions from a decrease in previously estimated quantities due to performance and price. A final investment decision has been made on all 61 locations, and they are scheduled to be drilled and completed in 2021 to 2023.

Estimated total future development and abandonment costs related to the development of proved undeveloped reserves as shown in our December 31, 2020 reserve report are $279.5 million. Based on this report and our PUD booking methodology, the capital estimated to be spent to develop the proved undeveloped reserves from spud date through production is $186.4 million in 2021, $84.1 million in 2022, $4.1 million in 2023, $0.9 million in 2024 and $0.2 million in 2025. Based on our anticipated cash flows and capital expenditures, as well as the availability of capital markets transactions, all of the proved undeveloped locations are expected to be drilled and completed in 2021 to 2023. Reserve calculations at any end-of-year period are representative of our development plans at that time. Changes in circumstance, including commodity pricing, oilfield service costs, drilling and production results, technology, acreage position and availability and other economic and regulatory factors may lead to changes in development plans.

Table of Contents

Acreage

The following table sets forth certain information regarding our developed and undeveloped acreage as of December 31, 2020, including acreage HBP. A majority of our developed acreage is subject to liens securing our Senior Secured Credit Facility.

	Developed acres		Undeveloped acres		Total acres		% HBP
	Gross	Net	Gross	Net	Gross	Net	
Permian-Midland Basin	132,914	117,436	18,970	15,763	151,884	133,199	88 %

The following table sets forth our gross and net undeveloped acreage as of December 31, 2020 that will expire over the next four years unless production is established within the spacing units covering the acreage or the lease is renewed, renegotiated or extended under continuous drilling provisions prior to the primary term expiration dates.

	Years ended December 31,							
	2021		2022		2023		2024	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Permian-Midland Basin	7,398	5,064	1,686	1,832	1,035	176	—	—

Of the total undeveloped acreage identified as potentially expiring over the next three years as of December 31, 2020, 3,642 net acres have associated PUD reserves on our reserve report as of December 31, 2020, which we anticipate drilling to hold or renewing the associated leases. These PUD reserves represent 39% of our total PUD reserves as of December 31, 2020.

Of the total undeveloped acreage identified as potentially expiring over the next four years as of December 31,2019, 3,799 net acres had associated PUD reserves on our reserve report as of December 31, 2019. All acreage potentially expiring in 2020 was retained by either drilling or renewing leases.

Marketing

We market the majority of production from properties we operate for both our account and the account of the other working interest owners. We sell substantially all of our production under contracts ranging from terms of one month to multiple years, all at monthly calculated market prices. We typically sell production to a relatively limited number of customers, as is customary in the exploration, development and production business; however, we believe that our customer diversification affords us optionality in our sales destination.

As of December 31, 2020, we were committed to deliver, for sale or transportation, fixed volumes of product under certain contractual arrangements that specify the delivery of a fixed and determinable quantity:

	Total	2021	2022	2023	2024 and after
Crude oil (MBbl):					
Sales commitments	19,595	9,125	8,660	1,810	—
Transportation commitments:					
Field	43,830	10,950	10,950	10,950	10,980
To U.S. Gulf Coast	83,175	15,525	13,365	12,775	41,510
Natural gas (MMcf):					
Sales commitments	76,217	13,083	12,562	9,492	41,080
Total commitments (MBOE)[(1)]	159,303	37,781	35,069	27,117	59,336

(1) BOE is calculated using a conversion rate of six Mcf per one Bbl.

We have firm field transportation agreements that enable us or the purchasers of our oil production to move oil from our production area to major market hubs, including Colorado City, Texas; Midland, Texas; and Crane, Texas. If not fulfilled, we are subject to firm transportation payments on excess pipeline capacity and other contractual penalties. These commitments are normal and customary for our business. A portion of our commitments are related to transportation commitments

extending into 2024 with Medallion Pipeline Company, LLC ("Medallion") under which Medallion provides firm transportation capacity from our established Reagan County and Glasscock County acreage for redelivery to various major market hubs. We also have a firm transportation agreement with BridgeTex Pipeline Company, LLC to move oil from Colorado City, Texas to the U.S. Gulf Coast. In 2018, we signed an agreement with Gray Oak Pipeline, LLC to initially transport 25,000 barrels of oil per day increasing to 35,000 barrels of oil per day of our production from Crane, Texas to the U.S. Gulf Coast. Our shipments under this contract began in the fourth quarter of 2019. We believe these commitments enhance our ability to move our crude oil out of the Permian Basin and give us access to U.S. Gulf Coast pricing.

We have committed to deliver, for sale or transportation, fixed volumes of product under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. See Note 16.c to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our transportation commitments.

We believe that we could sell our production to numerous companies, so that the loss of any one of our major purchasers would not have a material adverse effect on our financial condition and results of operations solely by reason of such loss. For discussion on purchasers that individually accounted for 10% or more of each (i) oil, NGL and natural gas sales and (ii) sales of purchased oil in at least one of the years ended December 31, 2020, 2019 and 2018, see Note 15 to our consolidated financial statements included elsewhere in this Annual Report. See also "Item 1A. Risk Factors—Risks related to our business—The inability of our significant customers to meet their obligations to us may materially adversely affect our financial results."

Title to properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often cursory investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include customary royalty interests, liens incident to operating agreements and for current taxes, obligations or duties under applicable laws, development obligations under oil and gas leases or net profit interests.

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil, NGL and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 12.5% to 25%, resulting in a net revenue interest to us generally ranging from 75% to 87.5%.

Seasonality

Demand for oil and natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Regulation of the oil and natural gas industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, the production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. The State of Texas has regulations governing environmental and conservation matters, including provisions for the pooling of oil and natural gas properties, the permitting of allocation wells, the establishment of maximum allowable rates of production from oil and natural gas wells (including the proration of production to the market demand for oil, NGL and natural gas), the regulation of well spacing, the handling and disposing or discharge of waste materials and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil, NGL and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, Texas imposes a production or severance tax with respect to the production and sale of oil, NGL and natural gas within its jurisdiction. Texas further regulates drilling and operating activities by, among other things, requiring permits and bonds for the drilling and operation of wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

The regulatory burden on the industry increases the cost of doing business and affects profitability. Additional proposals and proceedings that affect the natural gas industry are regularly considered by the current administration, Congress, the states, the Environmental Protection Agency ("EPA"), the Federal Energy Regulatory Commission ("FERC") and the courts. We cannot predict when or whether any such proposals may become effective, under the current or any future administration.

We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered, and such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impacts of compliance.

Regulation of oil and gas pipelines

Our oil and gas pipelines are subject to construction, installation, operation and safety regulation by the U.S. Department of Transportation ("DOT") and various other federal, state and local agencies. Congress has enacted several pipeline safety acts over the years. Currently, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") under DOT administers pipeline safety requirements for natural gas and hazardous liquid pipelines. These regulations, among other things, address pipeline integrity management and pipeline operator qualification rules. In June 2016, Congress approved new pipeline safety legislation, the "Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016", which provides the PHMSA with additional authority to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of gas or hazardous liquids pipeline facilities. On October 1, 2019, PHMSA published final rules to expand its integrity management requirements and impose new pressure testing requirements on regulated pipelines, including certain segments outside high consequence areas. The rules, once effective, also extend reporting requirements to certain previously unregulated hazardous liquid gravity and rural gathering lines. Additional rulemakings are anticipated, including rulemakings to adjust repair criteria for gas transmission lines, to require inspection of gas pipelines following extreme events, and to extend regulatory safety requirements to certain gas gathering lines.

States are largely pre-empted by federal law from regulating pipeline safety but may assume responsibility for enforcing intrastate pipeline regulations at least as stringent as the federal standards, and many states have undertaken responsibility to enforce the federal standards. The Railroad Commission of Texas is the agency vested with intrastate natural gas pipeline regulatory and enforcement authority in Texas. The Commission's regulations adopt by reference the minimum federal safety standards for the transportation of natural gas. In addition, on December 17, 2019, the Commission adopted rules requiring that operators of gathering lines take "appropriate" actions to fix safety hazards.

Regulation of environmental and occupational health and safety matters

Our operations are subject to numerous stringent federal, state and local statutes and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment or occupational health and safety. Numerous governmental agencies, such as the EPA, issue regulations that often require difficult and costly compliance measures, the noncompliance with which carries substantial administrative, civil and criminal penalties and may result in injunctive obligations to remediate noncompliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, govern the sourcing and disposal of water used in the drilling, completion and production process, limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier, seismically active areas and other protected areas, require some form of remedial action to prevent or mitigate pollution from current or former operations such as plugging abandoned wells or closing earthen pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of production.

Certain of these laws and regulations impose strict liability (i.e., no showing of "fault" is required) that, in some circumstances, may be joint and several. Public interest in the protection of the environment has tended to increase over time. The trend of more expansive and stringent environmental legislation and regulations applied to the oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. Changes in environmental laws and regulations occur frequently, and to the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and clean-up requirements, our business and prospects, as well as the oil and natural gas industry in general, could be materially adversely affected.

Hazardous substance and waste handling

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes, and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict and, in some cases, joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. The Comprehensive Environmental Response, Compensation, and Liability Act, as amended (referred to as "CERCLA" or the "Superfund law") and comparable state laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons deemed "responsible parties." These persons include current owners or operators of the site where a release of hazardous substances occurred, prior owners or operators that owned or operated the site at the time of the release or disposal of hazardous substances, and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to strict and joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. Despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. In addition, we may have liability for releases of hazardous substances at our properties by prior owners or operators or other third parties. Finally, it is not uncommon for neighboring landowners and other third parties to file common law based claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

The Oil Pollution Act of 1990 (the "OPA") is the primary federal law imposing oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. Under the OPA, strict, joint and several liability may be imposed on "responsible parties" for all containment and clean-up costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters and natural resource damages, resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility. The OPA establishes a liability limit for onshore facilities, but these liability limits may not apply if: a spill is caused by a party's gross negligence or willful misconduct; the spill resulted from a violation of a federal safety, construction or operating regulation; or a party fails to report a spill or to cooperate fully in a clean-up. We are also subject to analogous state statutes that impose liabilities with respect to oil spills.

We also generate solid wastes, including hazardous wastes, which are subject to the requirements of the Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. Although RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA's hazardous waste regulations. These wastes, instead, are regulated under RCRA's less stringent solid waste provisions, state laws or other federal laws. It is also possible that these wastes, which could include wastes currently generated during our operations, will be designated as "hazardous wastes" in the future and, therefore, be subject to more rigorous and costly disposal requirements. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration and production wastes as "hazardous wastes." Also, in December 2016, the EPA agreed in a consent decree to review its regulation of oil and gas waste. However, in April 2019, the EPA concluded that revisions to the federal regulations for the management of oil and gas waste are not necessary at this time. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

We believe that we are in substantial compliance with the requirements of CERCLA, RCRA, OPA and related state and local laws and regulations, and that we hold all necessary and up-to-date permits, registrations and other authorizations required under such laws and regulations. Although we believe that the current costs of managing our wastes as they are presently classified are reflected in our budget, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Water and other waste discharges and spills

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act, the Safe Drinking Water Act ("SDWA"), the OPA and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers ("Corps"). On June 29, 2015, the EPA and the Corps jointly promulgated final rules redefining the scope of waters protected under the Clean Water Act. However, on October 22, 2019, the agencies repealed the 2015 rules. Both the 2015 rules and the 2019 repeal are subject to ongoing legal challenges. Also, on April 21, 2020, the EPA and the Corps published a final rule replacing the 2015 rules, and significantly reduced the waters subject to federal regulation under the Clean Water Act. Several state and environmental groups have challenged the replacement rules. As a result of such recent developments, substantial uncertainty exists regarding the scope of waters protected under the Clean Water Act. To the extent the rules expand the range of properties subject to the Clean Water Act's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. The State of Texas also maintains groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The underground injection of fluids is subject to permitting and other requirements under state laws and regulation. Obtaining permits has the potential to delay the development of oil and natural gas projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development, and require us to incur compliance costs.

These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances and may impose substantial potential liability for the costs of removal, remediation and damages. Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and the underground injection of fluids and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of significant quantities of oil. We maintain all required discharge permits necessary to conduct our operations, and we believe we are in substantial compliance with their terms.

Hydraulic fracturing

We use hydraulic fracturing as a means to maximize the productivity of almost every well that we drill and complete. Hydraulic fracturing is a necessary part of the completion process for our producing properties in Texas because our properties are dependent upon our ability to effectively fracture the producing formations in order to produce at economic rates. While hydraulic fracturing is not required to maintain any of our leasehold acreage that is currently held by production from existing wells, it will be required in the future to develop the provided non-producing and proved undeveloped reserves associated with this acreage. Nearly all of our proved undeveloped reserves associated with future completion, recompletion and refracture stimulation projects require hydraulic fracturing.

Hydraulic fracturing is a practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We have and continue to follow standard industry practices and applicable legal requirements. These protective measures include setting surface casing at a depth sufficient to protect fresh water formations and cementing the

well to create a permanent isolating barrier between the casing pipe and surrounding geological formations. This well design is intended to eliminate a pathway for the fracturing fluid to contact any aquifers. For recompletions of existing wells, the production casing is pressure tested prior to perforating the new completion interval. Injections rates and pressures are monitored in real time at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. Hydraulic fracturing operations would be shut down immediately if an abrupt change occurred to the injection pressure or annular pressure.

Approximately 99% of the hydraulic fracturing fluids we use are made up of water and sand. The remainder of the constituents in the fracturing fluid are managed and used in accordance with applicable requirements. In accordance with Texas regulations, we report the constituents of the hydraulic fracturing fluids utilized in our well completions on FracFocus (www.fracfocus.org). Hydraulic fracture stimulation requires the use of a significant volume of water. Upon flowback of the water, we dispose of it by recycling or by discharging into the approved disposal wells. We currently do not discharge water to the surface. Based upon results of testing the performance of recycled flowback/produced water in our fracing operations, we endeavor to maximize the utilization of recycled flowback/produced water via our owned and operated recycling facilities in Glasscock and Reagan County or via contractual arrangements with third parties in Howard County.

The SDWA regulates the underground injection of substances through the Underground Injection Control Program (the "UIC"). However, hydraulic fracturing is generally exempt from regulation under the UIC, and thus the process is typically regulated by state oil and gas commissions. Nevertheless, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the UIC. On February 12, 2014, the EPA published a revised UIC Program permitting guidance for oil and natural gas hydraulic fracturing activities using diesel fuel. The guidance document describes how Class II regulations may be tailored to address the purported unique risks of diesel fuel injection during the hydraulic fracturing process. Although the EPA is not the permitting authority for UIC Class II programs in Texas, where we maintain acreage, the EPA is encouraging state programs to review and consider use of this permit guidance. Furthermore, legislation has been proposed in recent sessions of Congress to repeal the hydraulic fracturing exemption from the SDWA, provide for federal regulation of hydraulic fracturing and require public disclosure of the chemicals used in the fracturing process.

In addition, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities. We cannot predict the impact that these actions may have on our business at this time, but further regulation of hydraulic fracturing activities could have a material impact on our business, financial condition and results of operation.

Also, on March 26, 2015, the Bureau of Land Management (the "BLM") published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing, implementation of a casing and cementing program, management of recovered fluids, and submission to the BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, and the depths of all usable water. On March 28, 2017, the Trump Administration issued an executive order directing the BLM to review the rule, and, if appropriate, to initiate a rulemaking to rescind or revise it. Accordingly, on December 29, 2017, the BLM published a final rule to rescind the 2015 hydraulic fracturing rule; however, a coalition of environmentalists, tribal advocates and the State of California filed lawsuits challenging the rule rescission. At this time, it is uncertain when, or if, the hydraulic fracturing rule will be implemented, and what impact it would have on our operations.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or

proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanism.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances, impose additional requirements on hydraulic fracturing activities or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, pursuant to legislation adopted by the State of Texas in June 2011, beginning February 1, 2012, companies were required to disclose to the RRC and the public the chemical components used in the hydraulic fracturing process, as well as the volume of water used. Also, in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. The new rules took effect in January 2014. Additionally, on October 28, 2014, the RRC adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed, new disposal well. The disposal well rule amendments, which became effective on November 17, 2014, also clarify the RRC's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The RRC has used this authority to deny permits for waste disposal wells. In addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular.

A number of lawsuits and enforcement actions have been initiated across the country alleging that hydraulic fracturing practices have induced seismic activity and adversely impacted drinking water supplies, use of surface water, and the environment generally. Several states and municipalities have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances. If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to drill and produce from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings. In addition, if hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. These developments, as well as new laws or regulations, could cause us to incur substantial compliance costs, and compliance or the consequences of failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if federal or state legislation governing hydraulic fracturing is enacted into law.

For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, please read "-Regulation of environmental and occupational health and safety matters-Hydraulic fracturing." For related risks to our stockholders, please read "Item 1A. Risk Factors—Risks related to our business—Federal and state legislation and regulatory initiatives relating to hydraulic fracturing and water disposal wells could prohibit projects or result in materially increased costs and additional operating restrictions or delays because of the significance of hydraulic fracturing and water disposal wells in our business."

Air emissions

The federal Clean Air Act, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations, through the issuance of permits and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Also, on May 12, 2016, the EPA issued a final rule regarding the criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects.

In August 2012, the EPA published final rules that subject oil and natural gas production, processing, transmission, and storage operations to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for

Hazardous Air Pollutants. The rules include NSPS for completions of hydraulically fractured gas wells and establish specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rules seek to achieve a 95% reduction in volatile organic compounds ("VOC") emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of these requests for reconsideration. In particular, on May 12, 2016, the EPA amended its regulations to impose new standards for methane and VOC emissions for certain new, modified and reconstructed equipment, processes and activities across the oil and natural gas sector. However, in a March 28, 2017 executive order, the Trump administration directed the EPA to review the 2016 regulations and, if appropriate, to initiate a rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation's energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. Accordingly on August 13, 2020, the EPA issued amendments to the 2012 and 2016 NSPS requirements to ease regulatory burdens, including rescinding standards applicable to transmission or storage segments and eliminating methane requirements altogether. Various state, municipal and environmental groups have challenged the amendments, and, on January 20, 2021, President Biden issued an executive order directing the EPA to review the amendments consistent with several policy objectives, including reducing greenhouse gas emissions. Thus substantial uncertainty exists regarding the scope of NSPS requirements for oil and natural gas operations.

In addition, on November 18, 2016, the BLM finalized a waste prevention rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The rule requires operators to use currently available technologies and equipment to reduce flaring, periodically inspect their operations for leaks, and replace outdated equipment that vents large quantities of gas into the air. The rule also clarifies when operators owe the government royalties for flared gas. On March 28, 2017, the Trump Administration issued an executive order directing the BLM to review the above rule and, if appropriate, to initiate a rulemaking to rescind or revise it. On September 28, 2018, the BLM finalized revisions to the waste prevention rule to reduce "unnecessary compliance burdens." However, a federal court struck down the scaled-back rule on July 15, 2020, and shortly thereafter, on October 8, 2020, another federal court struck down the 2016 waste prevention rule. At this time, it is uncertain when, and to what extent, the waste prevention rule will be implemented, and what impact it will have on our operations.

The above standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions.

We have incurred additional capital expenditures to ensure compliance with these new regulations as they come into effect. We may also be required to incur additional capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits addressing other air emission related issues, which may have a material adverse effect on our operations. Obtaining permits also has the potential to delay the development of oil and natural gas projects. We believe that we currently are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our current operations.

Regulation of "greenhouse gas" emissions

In recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases ("GHGs"). The EPA has finalized a series of GHG monitoring, reporting and emission control rules for the oil and natural gas industry, and Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of the states have already taken measures to reduce GHG emissions primarily through the development of GHG emission inventories and/or regional GHG cap-and-trade programs. Also, states have imposed increasingly stringent requirements related to the venting or flaring of gas during oil and gas operations. In addition, some states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

At the international level, in December 2015, the United States participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties

to undertake "ambitious efforts" to limit the average global temperature and to conserve and enhance sinks and reservoirs of GHGs. The Paris Agreement went into effect on November 4, 2016. Although the United States withdrew from the Paris Agreement, effective November 4, 2020, President Biden issued an Executive Order on January 20, 2021 to rejoin the Paris Agreement, which will take effect on February 19, 2021. Furthermore, many state and local leaders have stated their intent to intensify efforts to support the commitments set forth in the international accord.

Restrictions on GHG emissions that may be imposed could adversely affect the oil and gas industry. The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil, NGL and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations.

Occupational Safety and Health Act

Certain of our operations are subject to applicable requirements of the federal Occupational Safety and Health Act, as amended ("OSHA") and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that certain information be provided to employees, state and local government authorities and citizens. We believe that we have measures, practices and policies in place to ensure that our operations are in substantial compliance with applicable federal OSHA and state occupational health and safety requirements.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Departments of Interior and Agriculture, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency prepares an environmental assessment to evaluate the potential direct, indirect and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a more detailed environmental impact study that is made available for public review and comment. Any exploration and production activities, as well as proposed exploration and development plans, on federal lands would require governmental permits that are subject to the requirements of NEPA. This environmental impact assessment process has the potential to delay the development of oil and natural gas projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Endangered Species Act

The Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species or its habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. If previously unprotected species, such as the dunes sagebrush lizard, are designated as endangered or threatened, or if we were to have a portion of our leases designated as critical or suitable habitat, it could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas, which could adversely impact the value of our leases.

Summary

In summary, we believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters during the years ended December 31, 2020, 2019 or 2018.

Regulation of derivatives

The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandates that the Commodity Futures Trading Commission (the "CFTC"), the SEC, and federal regulators of financial institutions (the "Prudential Regulators") adopt rules or regulations implementing the Dodd-Frank Act and providing definitions of terms used in the Dodd-Frank Act. The Dodd-Frank Act establishes margin requirements and requires clearing and trade execution practices for certain market participants and may result in certain market participants needing to curtail or cease their derivatives activities.

The CFTC, the SEC and the Prudential Regulators have issued many rules to implement the Dodd-Frank Act, including rules (the "Adopted Derivatives Rules") requiring clearing of hedges, or swaps, that are subject to it (currently, only certain interest rate and credit default swaps, which we do not presently have (the "Mandatory Clearing Rule"), establishing an "end user" exception to the Mandatory Clearing Rule (the "End User Exception"), setting forth collateral requirements in connection with swaps that are not cleared (the "Margin Rule") and also an exception to the Margin Rule for end users that are not financial end users (the "Non-Financial End User Exception") imposing position limits on certain futures contracts, including the NYMEX "Henry Hub" gas contract and "Light Sweet Crude" oil contract, and economically equivalent swaps (the "Position Limit Rule"). The Position Limit Rule is scheduled to take effect March 15, 2021 with the position limits provided for in the Position Limit Rule taking effect on January 1, 2022. The Position Limit Rule provides an exemption from the position limits for swaps that constitute "bona fide hedging positions" within the definition of such term under the Position Limit Rule, subject to the party claiming the exemption complying with the applicable filing, recordkeeping and reporting requirements of the Position Limit Rule.

We qualify for the End User Exception and will utilize it if the Mandatory Clearing Rule is expanded to cover swaps in which we participate, we qualify for the Non-Financial End User Exception and will not be required to post margin in connection with uncleared swaps under the Margin Rule, and our existing and anticipated hedging positions constitute "bona fide hedging positions" under the Position Limit Rule, and we intend to undertake the filing, recordkeeping and reporting necessary to utilize the bona fide hedging position exemption under the Position Limit Rule when it becomes effective, so we do not expect to be directly affected by any such rules. However, most if not all of our hedge counterparties will be subject to mandatory clearing in connection with their hedging activities with parties who do not qualify for the End User Exception and will be required to post margin in connection with their hedging activities with other swap dealers, major swap participants, financial end users and other persons that do not qualify for the Non-Financial End User Exception. In addition, the European Union and other non-U.S. jurisdictions have enacted laws and regulations (including laws and regulations giving the European Union financial authorities the power to write down amounts we may be owed on hedging agreements with counterparties subject to such laws and regulations and/or require that we accept equity interests in such counterparties in lieu of cash in satisfaction of such amounts, collectively the "Foreign Regulations"), which may apply to our transactions with counterparties subject to such Foreign Regulations (the "Foreign Counterparties") and the U.S. adopted law and rules (the "U.S. Resolution Stay Rules") clarifying similar rights of U.S. banking authorities with respect to banking institutions subject to their regulation.

Disclosures required pursuant to Section 13(r) of the Securities Exchange Act of 1934

Pursuant to Section 13(r) of the Securities Exchange Act of 1934, we, Laredo, are required to disclose in our periodic reports to the SEC, whether we or any of our "affiliates" (as defined in Rule 12b-2 under the Exchange Act) knowingly engaged in certain activities, transactions or dealings relating to Iran or with certain individuals or entities targeted by United States' economic sanctions during the period covered by the report. Disclosure is generally required even where the activities, transactions or dealings were conducted in compliance with applicable law. Because the SEC defines the term "affiliate" broadly, it includes any entity under common "control" with us (and the term "control" is also construed broadly by the SEC). Neither we nor any of our affiliates engaged in certain activities, transactions or dealings relating to Iran or with certain individuals or entities targeted by United States' economic sanctions during the period covered by the report.

Human Capital

The *Laredo Way* is a path designed for our employees to experience mutual respect, openness, honesty and a spirit of trust and collaboration while employed by Laredo. Laredo's key human capital objectives are to attract, retain, motivate and develop the highest quality talent possible. To support these objectives, we support and encourage an inclusive work

environment to help our employees attain their highest level of productivity, creativity and efficiency. Diverse and sound ideas, approaches and individual experiences are essential features of inclusion. We foster an environment of safety and inclusion through the implementation of our Code of Conduct and Business Ethics and annual anti-harassment training. We firmly believe that everyone at Laredo contributes to our success.

Workforce Composition

As of December 31, 2020, we employed 257 full-time employees, 123 of which were based in our field offices. We also employed a total of 24 contract personnel who assist our full-time employees with respect to specific tasks and perform various field and other services. Nearly one-half of our employees possess technical and professional backgrounds, often holding advanced degrees. Our professional staff includes geoscientists, petroleum and chemical engineers, land women and men, accountants, computer and data scientists, financial analysts, lawyers and human resource specialists. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory.

Diversity and Inclusion

We believe that a diverse workforce will help our organization better accomplish our mission. We are proud that nearly 30% of our leadership positions are filled by women. To increase our hiring of traditionally underrepresented groups and women, Laredo proactively sources open positions on job sites specifically focused on diversity. This allows us to gain candidates from underrepresented talent pools to help fill our positions. At the end of our fiscal year 2020, our workforce identified as or consisted of:

- 25% diverse based on ethnicity
- 27% women
- 38% women in professional roles or higher
- 5% US military veterans

Laredo strives to provide a comfortable and progressive workplace where communication is open and problems can be discussed and resolved in a mutually respectful atmosphere. We take into account individual circumstances and the individual employee. Working together, we are stronger, and we will continue to honor diversity and inclusion as key values of the *Laredo Way*.

Health and Safety

We know that an engaged, healthy, safe and well-trained workforce is key to our world-class culture and helps us accomplish our strategic goals. Safety is a core part of Laredo's culture, and we pride ourselves on our commitment to conduct all operations in a safe manner. We are always striving for an incident free workplace and we are proud of our record of safe operations. Our safety best practices include: annual job training, pre-job safety meetings, on-site contractor management and safety personnel, hazard hunts, bi-annual external safety audits, stop work authority, after-action review and root cause analysis.

As we continue to adapt to new ways of working during the COVID-19 pandemic, we will continue to operate responsibly while always putting the safety and well-being of our employees, their families and our communities first. We have implemented several measures for all employees, such as keeping pay and benefits whole for those who are finding their work routines disrupted by the pandemic and limiting in-person or onsite gatherings to essential and safety purposes only. We are monitoring the pandemic closely and are committed to prioritizing the health and safety of our people and communities above all else.

Total Rewards

To attract and retain exceptional talent, we provide our employees a comprehensive total rewards program, which includes a comprehensive benefits offering and competitive compensation package. We recognize that by offering relevant and innovative total rewards programs to our employees, we send a message that we are listening to their needs and promoting flexibility as well as sound health and wellness opportunities. In addition to competitive salaries, we offer both short and long term incentive programs, company-matched 401K contributions, flexible working schedules and many more employee-focused programs. Demonstrating our commitment to our employees' health and well-being, highlighted below are several benefits of our total rewards program.

- ***Healthcare****:* We cover over 80% of health insurance premiums to ensure our employees and their families have access to affordable healthcare.
- ***Fitness***: We provide an onsite fitness center for our Tulsa employees and access to local fitness facilities for our field personnel.
- ***Family***: We provide flexible work schedules to enable our employees to attend important family events during the workday and onsite lactation rooms to provide mothers with a calm and private space.
- ***Trust***: We provide a hotline for employees and contractors to report grievances without retaliation and allow us to review and adjust policies, where necessary.

Training

Identifying, attracting, retaining, motivating and developing our employees is crucial to all aspects of our long-term success and is central to our long-term strategy. We recognize and support our employees' desire to continue to learn and develop and offer opportunities both internally and externally to participate in learning programs. We offer tuition reimbursement benefits for extended educational learning opportunities. Additionally, we have a robust training program for our lease operators and field technicians that provides consistency in our processes and gives the management team clarity when considering field employees for promotional opportunities. Administration of this program is a joint effort between leadership on the production team and the learning and development staff that allows us to train our employees with the goal of promoting from within for all promotions in the field. We pride ourselves on the ability to promote our talented employees. We will continue to invest in our employees to ensure that we continue building an inclusive culture that inspires loyalty and encourages innovation as key values of the *Laredo Way*.

Available information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC, which are available to the public from commercial document retrieval services and at the SEC's website at http://www.sec.gov. Our common stock is listed and traded on the New York Stock Exchange under the symbol "LPI."

We also make available on our website (http://www.laredopetro.com) all of the documents that we file with the SEC and amendments to those reports, including related exhibits and supplemental schedules, filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Our Code of Conduct and Business Ethics, Code of Ethics For Senior Financial Officers, Corporate Governance Guidelines and the charters of our audit committee, compensation committee and nominating and corporate governance committee are also available on our website and in print free of charge to any stockholder who requests them. Requests should be sent by mail to our corporate secretary at our executive office. Information contained on our website is not incorporated by reference into this Annual Report. We intend to disclose on our website any amendments or waivers to our Code of Ethics that are required to be disclosed pursuant to Item 5.05 of Form 8-K.

Item 1A. Risk Factors

Our business involves a high degree of risk. If any of the following risks, or any risks described elsewhere in this Annual Report, were actually to occur, our business, financial condition or results of operations could be materially adversely affected and the trading price of our shares could decline resulting in the loss of part or all of your investment. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial may also adversely affect us.

Risks related to our business

Our business and operations have been and will likely continue to be adversely affected by the recent COVID-19 pandemic and responses.

The spread of the COVID-19 coronavirus caused, and is continuing to cause, severe disruptions in the worldwide and U.S. economy, including the global and domestic decreased demand for oil and natural gas, which has had an adverse effect on our business, financial condition and results of operations. Moreover, since the beginning of January 2020, the COVID-19 pandemic has caused significant disruption in the financial markets both globally and in the United States. The continued spread of the COVID-19 coronavirus could also negatively impact the availability of key personnel and adequate staffing for field operations necessary to conduct our business. If the COVID-19 coronavirus continues to spread or the response to contain the COVID-19 pandemic is unsuccessful, we could continue to experience a material adverse effect on our business, financial condition and results of operations.

The duration and extent to which the COVID-19 crisis and oil price volatility adversely affects our business, financial condition and results of operations will depend on future developments, which are highly uncertain and cannot be predicted, including the scope and duration of the pandemic and actions taken by oil producing countries, governmental authorities and other third parties in response. Current levels in the price of oil, NGL and natural gas, as well as ongoing volatility, have also had an adverse impact on both the level at which we are able to hedge our anticipated production and the cost, whether in terms of premiums for puts or foregone upside for collars, of such hedging which could continue to materially and adversely affect us, and we cannot predict the ultimate impact of this situation on, business, financial condition and results of operations.

As a result of the volatility in prices for oil, NGL and natural gas, we have taken and may be required to take further write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we have been required to, and may be required to further, write-down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations–Pricing and reserves" and Note 6.a to our consolidated financial statements included elsewhere in this Annual Report for additional information.

Oil, NGL and natural gas prices are volatile. The continuing and extended volatility in oil, NGL and natural gas prices has adversely affected, and may continue to adversely affect, our business, financial condition and results of operations and may in the future affect our ability to meet our capital expenditure obligations and financial commitments as well as negatively impact our stock price.

The prices we receive for our oil, NGL and natural gas production heavily influence our revenue, profitability, access to capital and future rate of growth. Commodity prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the market for oil, NGL and natural gas has been volatile and will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- the effects, duration, government response or other implications of the outbreak and continued spread of COVID-19, or the threat and occurrence of other epidemic or pandemic diseases;
- worldwide and regional economic and financial conditions, as well as legal, tax, political and administrative developments, impacting the global supply and demand for oil, NGL and natural gas;

- actions of OPEC+ relating to oil, NGL and natural gas production and price controls;
- the level of global oil, NGL and natural gas exploration, production and supplies, in particular due to supply growth from the United States;
- foreign and domestic supply capabilities for oil, NGL and natural gas;
- the price and quantity of U.S. imports and exports of oil, natural gas, including liquefied natural gas, and NGL;
- the pricing disparity between oil and natural gas and the negative effect it may have on our cash flow from operations;
- political conditions in or affecting other oil, NGL and natural gas-producing countries;
- the extent to which U.S. shale producers act as "swing producers" adding or subtracting to the world supply of oil, NGL and natural gas;
- future regulations prohibiting or restricting our ability to apply hydraulic fracturing to our wells;
- current and future regulations regarding well spacing;
- prevailing prices on local oil, NGL and natural gas price indexes in the areas in which we operate;
- localized and global supply and demand fundamentals and transportation availability;
- weather conditions and outbreak of disease;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- domestic, local and foreign governmental regulation and taxes.

Lower oil, NGL and natural gas prices have reduced, and may in the future continue to reduce, our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil, NGL and natural gas reserves as existing reserves are depleted. A further decrease in oil, NGL and natural gas prices could render uneconomic a large portion of our exploration, development and exploitation projects. This has already resulted in us having to make significant downward adjustments to our estimated proved reserves, and we may need to make further downward adjustments in the future. Furthermore, under our Senior Secured Credit Facility, scheduled borrowing base redeterminations occur by May 1 and November 1 of each year, and the lenders have the right to call for an interim redetermination of the borrowing base one time between any two scheduled redetermination dates and in other specified circumstances. A reduced borrowing base could trigger repayment obligations under our Senior Secured Credit Facility. Also, lower oil, NGL and natural gas prices would likely cause a decline in our stock price.

There is no guarantee that we will be successful in optimizing our spacing, drilling and completions techniques in order to maximize our rate of return, cash flow from operations and shareholder value.

As we accumulate and process geological and production data, we attempt to create a development plan, including well spacing and completion design, that maximizes our rate of return, cash flow from operations and shareholder value. However, due to many factors, including some beyond our control, there is no guarantee that we will be able to find the optimal plan or one that provides continuous improvement. If we are unable to design and implement an effective spacing, drilling and completions strategy, it may have a material adverse effect on our production results, financial performance, stock price and net asset value.

Competition in the oil and natural gas industry is intense, making it difficult for us to acquire properties, market oil, NGL and natural gas and secure trained personnel.

Our ability to acquire additional locations and to find and develop reserves in the future may depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive, concentrated geographic environment for acquiring properties, marketing oil, NGL and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil, NGL and natural gas industry, especially in our focus

areas. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil, NGL and natural gas properties and exploratory locations and to evaluate, bid for and purchase a greater number of properties and locations than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

We may be subject to risks in connection with acquisitions and disposition of assets.

The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil, NGL and natural gas prices and their applicable differentials;
- timing of development;
- capital and operating costs; and
- potential environmental and other liabilities.

The successful disposition of assets requires an assessment of several factors, including historical operations, potential environmental and other liabilities and impact on our business. The accuracy of these assessments is inherently uncertain. Our assessment will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller or buyer may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire or sell assets on an "as is" basis. Even in those circumstances in which we have contractual indemnification rights for pre-closing liabilities, it remains possible that the seller or buyer will not be able to fulfill its contractual obligations. Problems with assets we acquire or dispose of could have a material adverse effect on our business, financial condition and results of operations.

We may be unable to quickly adapt to changes in market/investor priorities.

Historically, one of the key drivers in the unconventional resource industry has been growth in production and reserves. With the continued downturn and volatility in oil and natural gas prices and the possibility that interest rates will rise increasing the cost of borrowing, capital efficiency and free cash flow from earnings have become the key drivers for energy companies, particularly shale producers. Shifts in focus such as these sometimes require changes in planning and resource management, which may not occur instantaneously. Any delay in responding to such changes in market sentiment or perception may result in the investment community having a negative sentiment regarding our business plan, potential profitability and our ability to operate in a manner deemed "efficient," which may have a negative impact on the price of our common stock.

Estimating reserves and future net cash flows involves uncertainties. Negative revisions to reserve estimates, decreases in oil, NGL and natural gas prices or increases in service costs, may lead to decreased earnings and increased losses or impairment of oil and natural gas properties.

The reserves data included in this Annual Report represent estimates. Reserves estimation is a subjective process of evaluating underground accumulations of oil, NGL and natural gas that cannot be measured in an exact manner. Reserves that are "proved reserves" are those estimated quantities of oil, NGL and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions and that relate to specific locations for which the extraction of hydrocarbons must have commenced or the operator must be reasonably certain will commence within a five-year period.

The estimation process relies on interpretations of available geological, geophysical, engineering and production data. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of developmental expenditures, including more rapid production declines than previously expected and many other factors beyond the control of the operator. Further, initial production rates reported by us or other operators may not be indicative of future or long-term production rates. Production declines may be rapid and irregular when compared to a well's initial production or initial estimates. In addition, the estimates of future net cash flows from our proved reserves and the present value of such estimates are based upon certain assumptions about future production levels, prices and costs that may not prove to be correct.

Negative revisions in the estimated quantities of proved reserves have the effect of increasing the rates of depletion on the affected properties, which decrease earnings or result in losses through higher depletion expense. These revisions, as well as revisions in the assumptions of future cash flows of these reserves, may also trigger impairment losses on certain properties, which would result in a non-cash charge to earnings. See Note 20.d to our consolidated financial statements included elsewhere in this Annual Report.

Unless we replace our oil, NGL and natural gas production, our reserves and production will continue to decline, which would adversely affect our future cash flows and results of operations.

Producing oil, NGL and natural gas reservoirs are generally characterized by rapidly declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploration, development and exploitation activities and/or continually acquire properties containing proved reserves, our proved reserves will continue to decline as those reserves are produced. Our future oil, NGL and natural gas reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

Insufficient transportation capacity in the Permian Basin, and the challenges to alleviating such transportation constraints, could cause significant fluctuations in our realized oil prices and our results of operations.

In our area of operation, the Permian Basin has been characterized by periods when oil and/or natural gas production has surpassed local transportation capacity, resulting in substantial discounts to the price received for crude oil prices quoted for WTI oil and Henry Hub natural gas. The expansion and construction of pipeline facilities are affected by the availability and costs of necessary equipment, supplies, labor and other services, as well as the length of time to complete such projects. In addition, these projects can be affected by changes in international trade relationships, including the imposition of trade restrictions or tariffs relating to crude oil and natural gas and any materials or products used to expand or construct pipeline facilities, such as certain imported steel mill products that are currently subject to a 25% global tariff on certain imported steel mill products. All of these factors could negatively impact our realized oil prices, as well as actual results of our operations.

The marketability of our production is dependent upon transportation, processing and storage, certain of which we do not control. If these services are unavailable, our operations could be interrupted and our revenues reduced.

The marketability of our oil, NGL and natural gas production depends on a variety of factors, including the availability, proximity, capacity and quality constraints of transportation, compression, natural gas processing, fractionation, export terminals and storage facilities owned by us or third parties. We do not control third-party facilities and pipelines that may be utilized for the transportation to market of the products originating at our leases. Our failure to provide or obtain such services on acceptable terms could materially harm our business.

Insufficient production from our wells to support the construction of pipeline facilities by third parties or a significant disruption in the availability of our or third-party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil, NGL and natural gas and thereby cause a significant interruption in our operations. If we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or specifications or encounter production-related difficulties, we may be required to shut in or curtail production. Any such shut-in or curtailment, or an inability to obtain favorable terms for delivery of the oil, NGL and natural gas produced from our fields, could materially and adversely affect our financial condition and results of operations.

A decrease in our production of oil, NGL and natural gas could negatively impact our ability to meet our contractual obligations to deliver oil, NGL and natural gas and our ability to retain our leases.

A portion of our oil, NGL and gas production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of extreme weather conditions, such as the freezing of wells and pipelines in the Permian Basin or a decision by the Electric Reliability Council of Texas ("ERCOT") to implement statewide electricity blackouts due to supply/

demand imbalances in the electricity grid caused by the extreme cold weather, accidents, loss or unavailability of pipeline or gathering system access and capacity, field labor issues or strikes. Alternatively, we might voluntarily curtail production in response to market conditions, including low oil, NGL and gas prices. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow. Furthermore, if we were required to shut in wells, we might also be obligated to pay shut-in royalties to certain mineral interest owners to maintain our leases.

In addition, we have entered into agreements with third party pipelines and purchasers that require us to deliver for transportation or sale minimum amounts of oil and natural gas. Pursuant to these agreements, we must deliver specific amounts of oil or gas over the next nine years. If we are unable to fulfill all of our contractual delivery obligations from our own production, we may be required to pay penalties or damages pursuant to these agreements or we may have to purchase oil from third parties to fulfill our delivery obligations. This could adversely impact our cash flows, profit margins and net income.

The potential drilling locations that we have tentatively internally identified for our future wells will be drilled, if at all, over many years. This makes them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Although our management team has established certain potential drilling locations as a part of our long-range development plan, our ability to drill and develop these locations depends on a number of uncertainties, including oil, NGL and natural gas prices, the availability and cost of capital, drilling and production costs, our ability to leverage our data and development experience, the availability of drilling services and equipment, lease expirations, gathering systems, marketing and pipeline transportation constraints, regulatory approvals and other factors. Because of these uncertainties, we do not know if the numerous potential drilling locations we have currently identified will ever be drilled or if we will be able to produce oil, NGL or natural gas from these or any other potential drilling locations. As such, it is likely that our actual drilling activities, especially in the long term, could materially differ from those presently anticipated.

Our use of 2D and 3D seismic, analytics and other data is subject to interpretation and may not accurately identify the presence of oil, NGL and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2D and 3D seismic data, analytics and other data that provide either visualization techniques and/or statistical analyses are only probability and estimation tools and do not ensure the existence of or the amount of hydrocarbons. We employ 3D seismic technology on certain of our projects, which is still relatively unproven. In addition, the use of 3D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, which may result in a reduction in our returns. As a result, our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline.

The inability of our significant customers to meet their obligations to us may materially adversely affect our financial results.

Our oil, NGL and natural gas production sales are made to a variety of purchasers, including intrastate and interstate pipelines or their marketing affiliates and independent marketing companies. Certain purchasers individually account for 10% or more of our oil, NGL and natural gas sales in a given year. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. See Notes 2.d and 15 to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our accounts receivable and credit risk, respectively.

The unavailability or high cost of additional oilfield services, including personnel, drilling rigs, equipment and supplies, as well as fees for the cancellation of such services, could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

The demand for and availability of qualified and experienced personnel to drill and complete wells and conduct field operations (including, but not limited to), frac crews, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil, NGL and natural gas prices, causing periodic shortages. From time to time, there have also been shortages of drilling and workover rigs, pipe, sand, water and equipment as demand for such items has increased along with the number of wells being drilled. We have committed in the past, and we may in the future commit, to drilling rig contracts with various third parties that contain penalties for early terminations. These penalties could negatively impact our financial statements upon contract termination. Shortages in rigs, crews, supplies and equipment, as well as related fees could result in delays or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

Our business could be negatively impacted by disruption of electronic systems, security threats, including cyber-security threats, and other disruptions.

We are heavily dependent on our information systems and computer-based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such systems or programs were to fail or we were subject to cyberspace breaches or attacks, possible consequences include our loss of communication links, inability to find, produce, process and sell oil, NGL and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

As an oil and natural gas producer, we face various security threats, including cyber-security threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the safety of our employees, threats to the security of our or third-party facilities and infrastructure, and threats from terrorist acts. In particular, cyber-security attacks are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows.

The loss of senior management or technical personnel and the failure to attract, train and retain qualified personnel could adversely affect our operations.

Effective succession planning is important to our long-term success. Failure to ensure effective transfer of knowledge and smooth transitions involving senior management and technical personnel could hinder our strategic planning and execution and could have a material adverse impact on our operations. We do not maintain any key-man or similar insurance for any officer or other employee.

We may not always foresee new operational/technical issues as new technology enables greater operational capabilities.

The unconventional oil and natural gas industry has seen a large increase in new technologies to enhance all aspects of operations. This has arguably accelerated as a result of the extended downturn in commodity prices, forcing companies to find new ways to more efficiently produce oil and natural gas. While such technologies can and often ultimately enhance operations, production and profitability, the utilization of such technologies, especially in their early phases, may result in unforeseen consequences and operational issues, resulting in negative consequences.

Conservation measures, technological advances and negative shift in market perception towards the Oil and Natural Gas Industry could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices, and the increased competitiveness of alternative energy sources could reduce demand for oil and natural gas. Additionally, the increased competitiveness of alternative energy sources (such as electric vehicles, wind, solar, geothermal, tidal, fuel cells and biofuels) could reduce demand for oil and natural gas and, therefore, our revenues.

Additionally, certain segments of the investor community have recently expressed negative sentiment towards investing in the oil and natural gas industry. Recent equity returns in the sector versus other industry sectors have led to lower oil and natural gas representation in certain key equity market indices. Some investors, including certain pension funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the oil and natural gas sector based on social and environmental considerations. Furthermore, certain other stakeholders have pressured commercial and investment banks to stop funding oil and gas projects. With the continued volatility in oil and natural gas prices, and the possibility that interest rates will rise in the near term, increasing the cost of borrowing, certain investors have

emphasized capital efficiency and free cash flow from earnings as key drivers for energy companies, especially shale producers. This may also result in a reduction of available capital funding for potential development projects, further impacting our future financial results.

The impact of the changing demand for oil and natural gas services and products, together with a change in investor sentiment, may have a material adverse effect on our business, financial condition, results of operations and cash flows. Furthermore, if we are unable to achieve the desired level of capital efficiency or free cash flow within the timeframe expected by the market, our stock price may be adversely affected.

Our operations are substantially dependent on the availability, use and disposal of water. New legislation and regulatory initiatives or restrictions relating to water disposal wells could have a material adverse effect on our future business, financial condition, operating results and prospects.

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners and other sources for use in our operations. Texas has previously experienced, and may experience again, low inflows of water. As a result of these conditions, some local water districts may begin restricting the use of water subject to their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil, NGL and natural gas, which could have an adverse effect on our results of operations, cash flows and financial condition.

Additionally, our operational and production procedures produce large volumes of water that we must properly dispose. The Clean Water Act, the Safe Drinking Water Act, the Oil Pollution Act, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the U.S. Environmental Protection Agency (the "EPA") or the state. Furthermore, the State of Texas maintains groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

Because of the necessity to safely dispose of water produced during operational and production activities, these regulations, or others like them, could have a material adverse effect on our future business, financial condition, operating results and prospects. See "Item 1. Business—Regulation of environmental and occupational health and safety matters" for a further description of the laws and regulations that affect us.

Our producing properties are in a concentrated geographic area, making us vulnerable to risks associated with operating in one major geographic area.

Our producing properties are geographically concentrated in the Permian Basin. As of December 31, 2020, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional transportation constraints, supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing and storage capacity constraints, market limitations, water shortages, interruption of the processing or transportation of oil or natural gas, as well as impacts from extreme weather or other natural disasters impacting the Permian Basin, such as the freezing of wells and pipelines in the Permian Basin or a decision by ERCOT to implement statewide electricity blackouts due to supply/demand imbalances in the electricity grid caused by the extreme cold weather.

If we were to experience an ownership change, we could be limited in our ability to use net operating losses arising prior to the ownership change to offset future taxable income. In addition, our ability to use net operating loss carryforwards to reduce future tax payments may be limited if our taxable income does not reach sufficient levels.

As of December 31, 2020, we had federal net operating loss ("NOL") carryforwards totaling $2.1 billion and state of Oklahoma NOL carryforwards totaling $34.6 million. If we were to experience an "ownership change," as determined under Section 382 of the Internal Revenue Code, of which Oklahoma conforms to, our ability to offset taxable income arising after the ownership change with NOLs arising prior to the ownership change would be limited, possibly substantially. An ownership change would establish an annual limitation on the amount of our pre-change NOL 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. 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 Internal Revenue Code) at any time during a rolling three-year period.

In addition, as a result of a comprehensive tax reform bill commonly referred to as the Tax Cuts and the Jobs Act (the "Tax Act"), NOL arising before January 1, 2018, and NOL arising on or after January 1, 2018, are subject to different rules. NOL arising before January 1, 2018, can generally be carried forward to offset future taxable income for a period of 20 years. Any NOL arising on or after January 1, 2018, while subject to additional limitations, can generally be carried forward indefinitely. Our ability to use our NOL during this period will be dependent on our ability to generate taxable income, and the NOL could expire before we generate sufficient taxable income. As of December 31, 2020, based on evidence available to us, including projected future cash flows from our oil, NGL and natural gas reserves and the timing of those cash flows, we believe a portion of our NOL is not fully realizable. As a result, as of December 31, 2020, a valuation allowance has been recorded against our net deferred tax assets. See Note 13 to our consolidated financial statements included elsewhere in this Annual Report for additional information.

Risks related to our financing and indebtedness

Our business requires significant capital expenditures and we may be unable to obtain needed capital or financing on satisfactory terms or at all.

Our exploration, development, marketing, transportation and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, proceeds from equity offerings, proceeds from senior unsecured note offerings, borrowings under our Senior Secured Credit Facility and proceeds from asset dispositions. We do not have commitments from anyone to contribute capital to us. Future cash flows are subject to a number of variables, including the level of production from existing wells, prices of oil, NGL and natural gas and our success in developing and producing new reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may have limited ability to obtain the additional capital necessary to sustain our operations at current levels. We may not be able to obtain debt or equity financing on terms favorable to us or at all. The failure to obtain additional capital could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a decline in our oil, NGL and natural gas production or reserves and, in some areas, a loss of properties.

Currently, we receive a level of cash flow stability as a result of our hedging activity. To the extent we are unable to obtain future hedges at beneficial prices or our commodity derivative activities are not effective, our cash flows and financial condition may be adversely impacted.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of oil, NGL and natural gas, we enter into commodity derivative instrument contracts for a portion of our oil, NGL and natural gas production, including puts, swaps, collars, basis swaps and, in the past, call spreads. In accordance with applicable accounting principles, we are required to record our derivatives at fair market value, and they are included in our consolidated balance sheet as assets or liabilities and in our consolidated statements of operations as gain (loss) on derivatives. Gain (loss) on derivatives are included in our cash flows from operating activities. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair market value of our derivative instruments, including a decrease in earnings if the price of commodities increases above the price of hedges that we have in place. As our current hedges expire, there is a significant uncertainty that we will be able to put new hedges in place that satisfy our hedge philosophy.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the commodity derivative instruments;
- the counter-party to the commodity derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

In addition, government regulation may adversely impact our ability to hedge these risks.

For additional information regarding our hedging activities, please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and Notes 10 and 11 to our consolidated financial statements included elsewhere in this Annual Report.

We may incur significant additional amounts of debt.

As of December 31, 2020, we had total long-term indebtedness of $1.19 billion. We may be able to incur substantial additional indebtedness, including secured indebtedness, in the future. The restrictions on the incurrence of additional indebtedness contained in the indentures governing our senior unsecured notes and in our Senior Secured Credit Facility are subject to a number of significant qualifications and exceptions, and under certain circumstances, the amount of indebtedness that could be incurred in compliance with these restrictions could be substantial. If new debt is added to our existing debt levels, the related risks that we face would increase and may make it more difficult to satisfy our existing financial obligations. In addition, the restrictions on the incurrence of additional indebtedness contained in the indentures governing the senior unsecured notes apply only to debt that constitutes indebtedness under the indentures. However, such increased debt may reduce the amount of outstanding debt allowed under the Senior Secured Credit Facility.

Increases in our cost of and ability to access capital could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce our cash flow and/or liquidity available for drilling and place us at a competitive disadvantage. An increase in interest rates on borrowings under our Senior Secured Credit Facility would result in increased annual interest expense and a decrease in our income before income taxes. Disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A downgrade in our credit ratings could negatively impact our costs of capital and our ability to effectively execute aspects of our strategy. Further, a downgrade in our credit ratings could affect our ability to raise debt in the public debt markets, and the cost of any new debt could be much higher than our outstanding debt. A significant reduction in our cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Interest rate risk" for additional information regarding interest rate risk. See Note 7 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our debt and borrowing base.

We require a significant amount of cash to service our indebtedness. Our ability to generate cash depends on many factors beyond our control.

Our ability to make payments on and to refinance our indebtedness and to fund planned capital expenditures depends on our ability to generate cash in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control. We cannot assure that we will generate sufficient cash flow from operations or that future funding will be available to us under our Senior Secured Credit Facility, equity offerings or other actions in an amount sufficient to enable us to pay our indebtedness or to fund our other liquidity needs. We may need to refinance all or a portion of our indebtedness at or before maturity. We cannot assure that we will be able to refinance any of our indebtedness on commercially reasonable terms or at all.

Any significant reduction in our borrowing base under our Senior Secured Credit Facility as a result of a periodic borrowing base redetermination or otherwise will negatively impact our liquidity and, consequently, our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our Senior Secured Credit Facility or any other obligation if required as a result of a borrowing base redetermination.

Availability under our Senior Secured Credit Facility is currently subject to a borrowing base which is subject to scheduled semiannual (May 1 and November 1) and other elective borrowing base redeterminations based upon, among other things, projected revenues from, and asset values of, the oil and natural gas properties securing the Senior Secured Credit Facility. The lenders under our Senior Secured Credit Facility can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Senior Secured Credit Facility. Reductions in estimates of our oil, NGL and natural gas reserves will result in a reduction in our borrowing base (if prices are kept constant). Reductions in our borrowing base could also arise from other factors, including but not limited to:

- lower commodity prices or production;
- increased leverage ratios;
- inability to drill or unfavorable drilling results;
- changes in oil, NGL and natural gas reserves engineering;

- increased operating and/or capital costs;
- the lenders' inability to agree to an adequate borrowing base; or
- adverse changes in the lenders' practices (including required regulatory changes) regarding estimation of reserves.

We anticipate borrowing under our Senior Secured Credit Facility in the future. Any significant reduction in our borrowing base as a result of such borrowing base redeterminations or otherwise will negatively impact our liquidity and our ability to fund our operations and, as a result, would have a material adverse effect on our financial position, results of operation and cash flow. Further, if the outstanding borrowings under our Senior Secured Credit Facility were to exceed the borrowing base as a result of any such redetermination, we could be required to repay the excess. We may not have sufficient funds to make such repayments. If we do not have sufficient funds and we are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results. In addition, we keep cash at certain banks that are not FDIC insured or such deposits that exceed the FDIC insured amount. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and capital resources" for additional information regarding our liquidity. See Note 7 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our debt and borrowing base.

We have incurred losses from operations for various periods since our inception and may do so in the future.

We incurred net losses in certain years of operation since our inception. Our development of and participation in an increasingly larger number of locations has required and will continue to require substantial capital expenditures. The uncertainty and factors described throughout this section may impede our ability to economically find, develop, exploit and acquire oil, NGL and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from operating activities in the future. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical accounting estimates."

Our debt agreements contain restrictions that limit our flexibility in operating our business.

Our Senior Secured Credit Facility and the indentures governing our senior unsecured notes each contain, and any future indebtedness we incur may contain, various covenants that limit our ability to engage in specified types of transactions. These covenants limit our ability to, among other things:

- incur additional indebtedness;
- pay dividends on, repurchase or make distributions in respect of our capital stock or make other restricted payments;
- make certain investments;
- sell certain assets;
- create liens;
- consolidate, merge, sell or otherwise dispose of all or substantially all of our assets; and
- enter into certain transactions with our affiliates.

As a result of these covenants and a covenant in our Senior Secured Credit Facility that limits our ability to hedge, we are limited in the manner in which we may conduct our business, and we may be unable to engage in favorable business activities or finance future operations or our capital needs. In addition, the covenants in our Senior Secured Credit Facility require us to maintain a minimum current ratio and maximum leverage ratio and also limit our capital expenditures. A breach of any of these covenants could result in a default under one or more of these agreements, including as a result of cross-default provisions and, in the case of our Senior Secured Credit Facility, permit the lenders to cease making loans to us. Upon the occurrence of an event of default under our Senior Secured Credit Facility, the lenders could elect to declare all amounts outstanding under our Senior Secured Credit Facility to be immediately due and payable and terminate all commitments to extend further credit. Such actions by those lenders could cause cross defaults under our other indebtedness, including the senior unsecured notes. If we were unable to repay those amounts, the lenders under our Senior Secured Credit Facility could proceed against the collateral granted to them to secure that indebtedness. We pledged a significant portion of our assets as collateral under our Senior Secured Credit Facility. If the lenders under our Senior Secured Credit Facility accelerate the

repayment of the borrowings thereunder, the proceeds from the sale or foreclosure upon such assets will first be used to repay debt under our Senior Secured Credit Facility, and we may not have sufficient assets to repay our unsecured indebtedness thereafter. Our Senior Secured Credit Facility matures on April 19, 2023.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We could be impacted by the outcome of pending litigation as well as unexpected litigation or proceedings. Certain litigation claims may not be covered under our insurance policies, or our insurance carriers may seek to deny coverage. Because we cannot accurately predict the outcome of any action, it is possible that, as a result of pending and/or unexpected litigation, we will be subject to adverse judgments or settlements that could significantly reduce our earnings or result in losses. See "Item 3. Legal Proceedings" for a description of our pending litigation.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil, NGL and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil, NGL and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- disagreements regarding the royalty due to our royalty owners;
- personal injuries and death;
- electronic system disruption and cyber-security threats;
- natural disasters; and
- terrorist attacks targeting oil, NGL and natural gas related facilities and infrastructure.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage and associated clean-up responsibilities;
- regulatory investigations, penalties or other sanctions;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The impact of litigation as well as the occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Derivatives reform legislation and related regulations could have an adverse effect on our ability to hedge risks associated with our business.

The Dodd-Frank Act, the Adopted Derivatives Rules, and the U.S. Resolution Stay Rules could significantly increase the cost of our derivative contracts, materially alter the terms of our derivative contracts, reduce the availability of derivatives to us that we have historically used to protect against risks that we encounter in our business, reduce our ability to monetize or restructure our existing derivative contracts and increase our exposure to less creditworthy counterparties. The Foreign Regulations could have similar effects. We have stopped entering into new hedging transactions with Foreign Counterparties and do not currently intend to resume hedging with Foreign Counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act, the Adopted Derivatives Rules, the U.S. Resolution Stay Rules, and Foreign Regulations, our results of

operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations. See "Item 1. Business—Regulation of derivatives" for a further description of the laws and regulations that affect us.

Risks related to regulation of our business

If we are unable to drill new allocation wells, it could have a material adverse impact on our future production results.

In the State of Texas, allocation wells allow an oil and gas producer to drill a horizontal well under two or more leaseholds that are not pooled. We are active in drilling and producing allocation wells. If regulations regarding allocation wells are made, the RRC denies or significantly delays the permitting of allocation wells or if legislation is enacted that negatively impacts the current process under which allocation wells are permitted, it could have an adverse impact on our ability to drill long horizontal lateral wells on some of our leases, which in turn could have a material adverse impact on our anticipated future production, rates of return and other projected capital efficiencies.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing and water disposal wells could prohibit projects or result in materially increased costs and additional operating restrictions or delays because of the significance of hydraulic fracturing and water disposal wells in our business.

Hydraulic fracturing is a practice that is used to stimulate production of oil and/or natural gas from tight formations. The process, which involves the injection of water, proppants and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, federal, state and local jurisdictions have adopted, or are considering adopting, regulations that could further restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. See "Item 1. Business—Regulation of environmental and occupational health and safety matters—Hydraulic fracturing" for a further description of federal and state regulations addressing hydraulic fracturing. Additionally, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices, which could spur initiatives to further regulate hydraulic fracturing. Additional levels of regulation and permits required through the adoption of new laws and regulations at the federal, state or local level could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if federal or state legislation or regulations governing hydraulic fracturing or water disposal wells are enacted into law.

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 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. See "Item 1. Business—Regulation of environmental and occupational health and safety matters—Hydraulic fracturing" for a further description of local regulations addressing seismic activity.

We dispose of large volumes of produced water gathered from our drilling and production operations by injecting it into wells pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. The adoption and

implementation of any new laws or regulations that restrict our ability to use hydraulic fracturing or dispose of produced water gathered from our drilling and production activities by owned disposal wells could have a material adverse effect on our business, financial condition and results of operations.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the Natural Gas Act of 1938 (the "NGA") exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission ("FERC"). We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish whether a pipeline performs a gathering function and, therefore, are exempt from the FERC's jurisdiction under the NGA. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is a fact-based determination. The classification of facilities as unregulated gathering is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress, which could cause our revenues to decline and operating expenses to increase and may materially adversely affect our business, financial condition or results of operations. In addition, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability, which could have a material adverse effect on our business, financial condition or results of operations.

The adoption of climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil, NGL and natural gas we produce, while potential physical effects of climate change could disrupt our operations and cause us to incur significant costs in preparing for or responding to those effects.

Restrictions on GHG emissions that may be imposed could adversely affect the oil and gas industry. The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil, NGL and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations.

See "Item 1. Business—Regulation of environmental and occupational health and safety matters—Regulation of “greenhouse gas" emissions" for a further discussion of the laws and regulations related to greenhouse gases.

Moreover, climate change may be associated with increased volatility in seasonal temperatures, as well as extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Extreme weather conditions can interfere with our production and increase our costs, and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our production and increase our costs, and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our business activities.

We may incur significant delays, costs and liabilities as a result of federal, state and local environmental, health and safety requirements applicable to our exploration, development, marketing, transportation and production activities. These laws and regulations may require us to obtain and maintain a variety of permits, approvals, certificates or other authorizations governing our air emissions, water discharges, waste disposal or other environmental impacts associated with drilling, production and transporting product pipelines or other operations; regulate the sourcing and disposal of water used in the drilling, fracturing and completion processes; limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier, seismically active areas and other protected areas; require remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; and/or impose

substantial liabilities for spills, pollution or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of oil or natural gas production. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed, and, in some instances, the issuance of orders or injunctions limiting or requiring discontinuation of certain operations.

Under certain environmental laws that impose strict as well as joint and several liability, we may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. In addition, accidental spills or releases from our operations could expose us to significant liabilities under environmental laws. Moreover, public interest in the protection of the environment has tended to increase over time. The trend of more expansive and stringent environmental legislation and regulations applied to the oil, NGL and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental actions are taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

See "Item 1. Business—Regulation of environmental and occupational health and safety matters" for a further description of the laws and regulations that affect us.

The results of the 2020 U.S. presidential and congressional elections may create regulatory uncertainty for the oil and natural gas industry. Changes in environmental laws could increase costs and harm our business, financial condition and results of operations.

Joe Biden's victory in the U.S. presidential election, as well as a closely divided Congress, may create regulatory uncertainty in the oil and natural gas industry. During his first weeks in office, President Biden has issued several executive orders promoting various programs and initiatives designed to, among other things, curtail climate change, control the release of methane from new and existing oil and gas operations, and pause new oil and gas leasing on public lands. It remains unclear what additional actions President Biden will take and what support he will have for any potential legislative changes from Congress. Further, it is uncertain to what extent any new environmental laws or regulations, or any repeal of existing environmental laws or regulations, may affect our operations. However, such actions could materially increase our costs or impair our ability to explore and develop other projects, which could materially harm our business, financial condition and results of operations.

Tax laws and regulations may change over time, and any such changes could adversely affect our business and financial condition.

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, including (i) the elimination of the immediate deduction for intangible drilling and development costs, (ii) the repeal of the percentage depletion allowance for oil and natural gas properties and (iii) an extension of 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. The elimination of such U.S. federal tax deductions, as well as any other changes to or the imposition of new federal, state, local or non-U.S. taxes (including the imposition of, or increases in production, severance or similar taxes) could adversely affect our business and financial condition.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil, NGL and natural gas operations in our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our

operations and materially increase our operating and capital costs. Permanent restrictions imposed to protect threatened or endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate, such as the dunes sagebrush lizard could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves.

Risks related to our common stock

Our amended and restated certificate of incorporation, amended and restated bylaws, and Delaware state law contain provisions that may have the effect of delaying or preventing a change in control and may adversely affect the market price of our capital stock.

Our amended and restated certificate of incorporation authorizes our board of directors to issue preferred stock without any further vote or action by the stockholders. The rights of the holders of our common stock will be subject to the rights of the holders of any preferred stock that may be issued in the future. The issuance of preferred stock could delay, deter or prevent a change in control and could adversely affect the voting power or economic value of our shares.

In addition, some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- limitations on the ability of our stockholders to call special meetings;
- a separate vote of 75% of the voting power of the outstanding shares of capital stock in order for stockholders to amend the bylaws in certain circumstances;
- our board of directors is divided into three classes with each class serving staggered three-year terms;
- stockholders do not have the right to take any action by written consent; and
- advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Delaware law prohibits us from engaging in any business combination with any "interested stockholder," meaning generally that a stockholder who owns 15% of our stock cannot acquire us for a period of three years from the date such stockholder became an interested stockholder, unless various conditions are met, such as the approval of the transaction by our board of directors. Provisions such as these are also not favored by various institutional investor services, which may periodically "grade" us on various factors, including stockholder rights and corporate governance policies. Certain institutional investors may have internal policies that prohibit investments in companies receiving a certain grade level from such services, and if we fail to meet such criteria, it could limit the number or type of certain investors which might otherwise be attracted to an investment in the Company, potentially negatively impacting the public float and/or market price of our common stock.

The availability of shares for sale in the future could reduce the market price of our common stock.

Our board of directors has the authority, without action or vote of our stockholders, to issue our authorized but unissued shares of common stock. In the future, we may issue securities to raise cash for acquisitions, to pay down debt, to fund capital expenditures or general corporate expenses, in connection with the exercise of stock options or to satisfy our obligations under our incentive plans. We may also acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities convertible into, exchangeable for, or that represent the right to receive, our common stock. Any of these events may dilute your ownership interest in our Company, reduce our earnings per share and have an adverse impact on the price of our common stock.

Because we have no plans to pay and are currently restricted from paying dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in us.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Covenants contained in our Senior Secured Credit Facility and the indentures governing our senior unsecured notes restrict the payment of dividends. Investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Investors seeking cash dividends should not purchase our common stock.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

The information required by Item 2. is contained in "Item 1. Business".

Item 3. Legal Proceedings

From time to time, we are subject to various legal proceedings arising in the ordinary course of business, including proceedings for which we may not have insurance coverage. While many of these matters involve inherent uncertainty as of the date hereof, we do not currently believe that any such legal proceedings will have a material adverse effect on our business, financial position, results of operations or liquidity. See Note 16.a to our consolidated financial statements included elsewhere in this Annual Report for further discussion of legal proceedings.

Item 4. Mine Safety Disclosures

The operation of our Howard County, Texas sand mine is subject to regulation by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Act"). MSHA may inspect our Howard County mine and may issue citations and orders when it believes a violation has occurred under the Mine Act. While we contract the mining operations of the Howard County mine to an independent contractor, we may be considered an "operator" for purposes of the Mine Act and may be issued notices or citations if MSHA believes that we are responsible for violations.

The information concerning mine safety violations and other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95.1 to this Annual Report.

Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market for Registrant's Common Equity

Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "LPI." On February 19, 2021, the last sale price of our common stock, as reported on the NYSE, was $35.06 per share.

Holders

As of February 15, 2021, there were 117 holders of record of our common stock.

Dividends

We have not paid any cash dividends since our inception. Covenants contained in our Senior Secured Credit Facility and the indentures governing our senior unsecured notes restrict the payment of cash dividends on our common stock. See "Item 1A. Risk Factors—Risks related to our financing and indebtedness—Our debt agreements contain restrictions that limit our flexibility in operating our business" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Debt." We currently intend to retain all future earnings for the development and growth of our business, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future.

Issuer Purchases of Equity Securities

The following table summarizes purchases of common stock by Laredo:

Period	Total number of shares purchased[(1)]	Weighted-average price paid per share[(1)]	Total number of shares purchased as part of publicly announced program	Maximum value that may yet be purchased under the program as of the respective period-end date
October 1, 2020 - October 31, 2020	566	$ 9.16	—	$ —
November 1, 2020 - November 30, 2020	—	$ —	—	$ —
December 1, 2020 - December 31, 2020	—	$ —	—	$ —
Total	566			

(1) Represents shares that were withheld by us to satisfy employee tax withholding obligations that arose upon the lapse of restrictions on restricted stock awards.

Unregistered Sales of Equity Securities and Use of Proceeds

None.

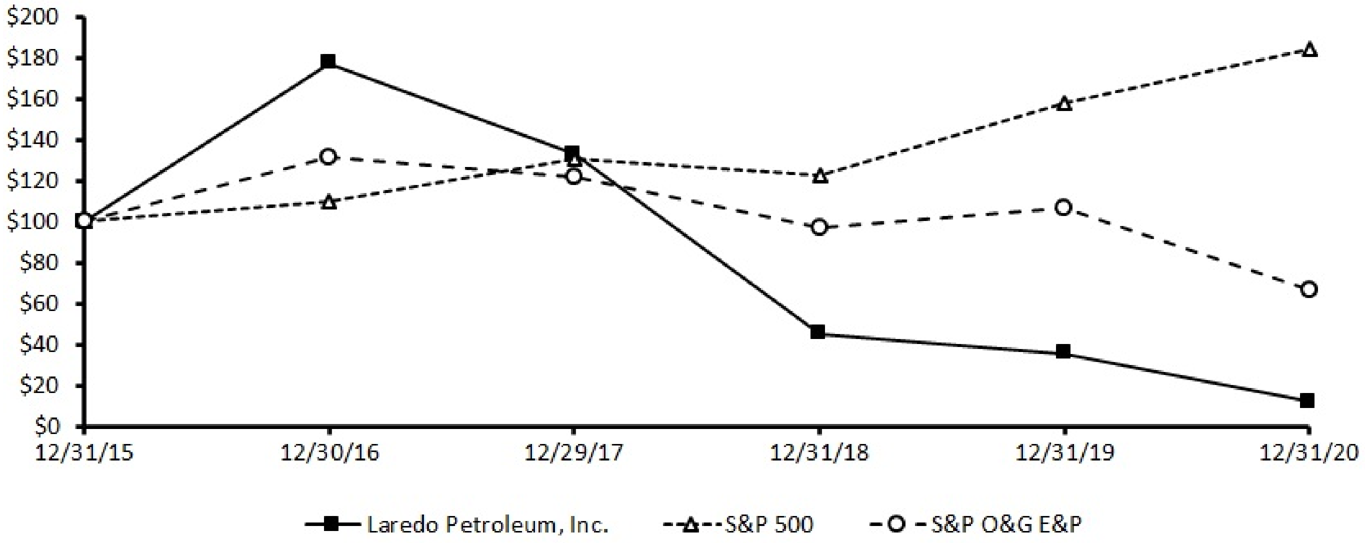
Stock Performance Graph

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act or Exchange Act, except to the extent that we specifically request that such information be treated as "soliciting material" or specifically incorporate such information by reference into such a filing.

The performance graph below compares the cumulative five-year total returns to our common stockholders relative to the cumulative total returns on the Standard and Poor's 500 Index (the "S&P 500") and the Standard and Poor's Oil & Gas Exploration & Production Select Industry Index (the "S&P O&G E&P"). The comparison was prepared based upon the following assumptions:

1. $100 was invested in our common stock, the S&P 500 and the S&P O&G E&P from December 31, 2015 to December 31, 2020; and

2. Dividends, if any, are reinvested.



Item 6. Selected Historical Financial Data

[Reserved.]

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations is for the year ended December 31, 2020 compared to 2019, and should be read in conjunction with our consolidated financial statements and notes thereto included elsewhere in this Annual Report. Additionally, see "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our 2019 Annual Report on Form 10-K for discussion and analysis of our financial condition and results of operations for the year ended December 31, 2019 compared to 2018. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions or beliefs about future events may, and often do, vary from actual results and the differences can be material. Please see "Cautionary Statement Regarding Forward-Looking Statements" and "Part I, Item 1A. Risk Factors." Unless otherwise specified, references to "average sales price" refer to average sales price excluding the effects of our derivative transactions.

Executive overview

We are an independent energy company focused on the acquisition, exploration and development of oil and natural gas properties, primarily in the Permian Basin of West Texas. Since our inception, we have grown primarily through our drilling program coupled with select strategic acquisitions and joint ventures.

Our financial and operating performance included the following for the periods presented and corresponding changes:

	Years ended December 31,		2020 compared to 2019	
(in thousands)	2020	2019	Change (#)	Change (%)
Oil sales volumes (MBbl)	9,827	10,376	(549)	(5)%
Oil equivalents sales volumes (MBOE)	32,117	29,522	2,595	9 %
Oil, NGL and natural gas sales[(1)]	$ 496,355	$ 706,548	$ (210,193)	(30)%
Net loss[(2)]	$ (874,173)	$ (342,459)	$ (531,714)	(155)%
Free Cash Flow (a non-GAAP financial measure)[(3)]	$ 12,056	$ 59,687	$ (47,631)	(80)%
Adjusted EBITDA (a non-GAAP financial measure)[(3)]	$ 506,924	$ 560,195	$ (53,271)	(10)%
Proved developed and undeveloped reserves MBOE[(4)]	278,228	293,377	(15,149)	(5)%

(1) Our oil, NGL and natural gas sales decreased as a result of a 35% decrease in average sales price per BOE and were partially offset by a 9% increase in total volumes sold.

(2) Our net loss for the years ended December 31, 2020 and 2019 includes non-cash full cost ceiling impairments of $889.5 million and $620.6 million, respectively.

(3) See pages 61-63 for discussions and calculations of these non-GAAP financial measures.

(4) See Note 20.d to our consolidated financial statements included elsewhere in this Annual Report for discussion of changes in our estimated proved reserve quantities of oil, NGL and natural gas.

Recent developments

Weather

During February 2021, severe winter weather affected our operations. As of February 22, 2021, our production is close to returning to pre-storm levels. We currently estimate that the combined impact of shut-in production and completions delays will reduce first-quarter 2021 total production by approximately 8,000 BOE per day and oil production by approximately 3,000 barrels per day.

Senior unsecured notes

On January 24, 2020, we completed an offer and sale (the "Offering") of $600.0 million in aggregate principal amount of 9.500% senior unsecured notes due 2025 (the "January 2025 Notes") and $400.0 million in aggregate principal amount of

10.125% senior unsecured notes due 2028 (the "January 2028 Notes"). Interest for both the January 2025 Notes and January 2028 Notes is payable semi-annually, in cash in arrears on January 15 and July 15 of each year. The first interest payment was made on July 15, 2020, and consisted of interest from closing to that date. The terms of the January 2025 Notes and January 2028 Notes include covenants, which are in addition to but different than similar covenants in the Senior Secured Credit Facility, which limit our ability to incur indebtedness, make restricted payments, grant liens and dispose of assets.

We received net proceeds of $982.0 million from the Offering, after deducting underwriting discounts and commissions and estimated offering expenses. The proceeds from the Offering were used (i) to fund tender offers for our January 2022 Notes and March 2023 Notes, (ii) to repay our January 2022 Notes and March 2023 Notes that remained outstanding after settling the tender offers and (iii) for general corporate purposes, including repayment of a portion of the borrowings outstanding under the Senior Secured Credit Facility.

In November 2020, our board of directors authorized a $50.0 million bond repurchase program. During the year ended December 31, 2020, we repurchased $22.1 million in aggregate principal amount of the January 2025 Notes and $39.0 million in aggregate principal amount of the January 2028 Notes for aggregate consideration of $13.9 million and $24.2 million, respectively, plus accrued and unpaid interest.

Acquisitions and divestiture of oil and natural gas properties

On October 16, 2020 and November 16, 2020, we closed a bolt-on acquisition of 2,758 and 80 net acres, including production of 210 BOE/D, in Howard County, Texas for a total purchase price of $11.6 million, subject to customary post-closing purchase price adjustments.

On April 30, 2020, we closed an acquisition of 180 net acres in Howard County, Texas for a total purchase price of $0.6 million, subject to one or more potential contingent payments to be paid by us.

On February 4, 2020, we closed a transaction for $22.5 million acquiring 1,180 net acres and divesting 80 net acres in Howard County, Texas.

On April 9, 2020, we closed a divestiture of 80 net acres and working interests in two producing wells in Glasscock County, Texas for a total sales price of $0.7 million, net of customary post-closing sales price adjustments.

See Note 4 included elsewhere in this Annual Report for discussion of these acquisitions and divestiture of oil and natural gas properties.

Quarterly Report restatement

On August 5, 2020, we filed an amendment to our first-quarter 2020 Quarterly Report to restate our unaudited consolidated financial statements for the quarter ended March 31, 2020 to correct an error in the future production costs component of the estimated present value ("PV-10") of our reserves. The omitted costs caused an understatement of approximately $160 million of the full cost ceiling impairment expense and balances of accumulated depletion and impairment and accumulated deficit, and a corresponding overstatement of the same amount to both net income and the balance of our oil and natural gas properties for the first quarter of 2020. This error was identified in the course of preparing our unaudited consolidated financial statements for the quarter ended June 30, 2020. This error was isolated to our first-quarter estimate of the PV-10 of our reserves and had no impact on our prior financial statements, including the 2019 Annual Report. This Annual Report gives effect to the restated financial information for the quarter ended March 31, 2020. In addition, we received a waiver from the lenders under our Senior Secured Credit Facility in connection with the error.

Reverse stock split

On June 1, 2020, we effected the previously announced 1-for-20 reverse stock split of our common stock and the related reduction of the number of authorized shares of common stock, which were previously approved by our stockholders at our 2020 annual meeting of stockholders. Our common stock began trading, on a reverse split-adjusted basis and under our existing trading symbol, at the opening of trading on June 2, 2020. See Note 8.a to our consolidated financial statements included elsewhere in this Annual Report for discussion of the reverse stock split.

Organizational restructuring

On June 17, 2020, we announced organizational changes, including a workforce reduction of 22 individuals, which included a senior officer, that were implemented immediately, subject to certain administrative procedures. In light of the COVID-19 pandemic and market conditions, our board of directors continues to monitor and evaluate our business and strategy and to reduce costs and better position us for the future. In connection with the organizational changes, we announced the departure of our former Senior Vice President and Chief Financial Officer ("former CFO"), effective as of June 17, 2020. Our former CFO's departure was not the result of any dispute or disagreement with us or our accounting practices or financial statements. We incurred $4.2 million of one-time organizational restructuring expenses during the year ended December 31, 2020, comprised of compensation, tax, professional, outplacement and insurance-related expenses. See Note 18 to our consolidated financial statements included elsewhere in this Annual Report for discussion of this organizational restructuring.

COVID-19

In December 2019, a highly transmissible and pathogenic strain of coronavirus surfaced in China, which has and is continuing to spread throughout the world, including the U.S. On January 30, 2020, the World Health Organization declared the outbreak of COVID-19 a "Public Health Emergency of International Concern," and on March 11, 2020, the World Health Organization characterized the outbreak as a "pandemic". The recommended actions by federal, state and local authorities to address the pandemic have resulted in a swift and unprecedented reduction in international and U.S. economic activity which, in turn, continues to adversely affect the demand for oil and natural gas and resulted in significant volatility and disruption of the financial markets. We are not able to predict the duration or ultimate impact that COVID-19 will have on our business, financial condition and results of operations. However, we have responded to these events with thoughtful planning and are committed to maintaining safe and reliable operations. The health and safety of our employees, suppliers, customers and business partners continue to be a top priority. Our policies to promote social distancing, both in the office and at field locations, remain in effect. Additionally, the majority of our non-field based employees successfully transitioned to working from home. We continue to closely monitor local infection rates and to conform to guidelines and best practices encouraged by the Centers for Disease Control and Prevention, the World Health Organization and other governmental and regulatory authorities to transition to appropriate return-to-work policies while minimizing interruptions to our operations. We do not believe that these measures have had a material effect on our workforce productivity.

On March 27, 2020, the Coronavirus Aid, Relief and Economic Security Act ("CARES Act") was enacted in response to the COVID-19 pandemic. It included provisions intended to provide relief to individuals and businesses in the form of loans and grants, and tax changes, among other provisions. We did not seek relief in the form of loans or grants from the CARES Act; however, we have benefited from the provision where the AMT credit carryforwards do not expire and are fully refundable.

Volatility in commodity prices

In early March 2020, concurrent with the spread of COVID-19 to the U.S. and just prior to the government actions mentioned above, members of OPEC+ proposed production cuts in an attempt to stabilize the oil market. However, OPEC+ failed to reach an agreement and some producers instead announced planned production increases, after which oil prices declined sharply. By mid-March 2020, WTI oil prices had declined to less than $25 per barrel, the lowest price since 2002. Although OPEC+ subsequently reached agreement in April 2020 on production cuts that went into effect in May 2020, oil prices continued to decline following announcement of the agreement. Further, producers in the U.S. and globally were slow to reduce oil production at a rate sufficient to match the sharp slowdown in economic activity caused by measures to control the spread of COVID-19. This resulted in an oversupply of oil that caused WTI oil prices to fall to -$37 per barrel on April 20th. Since the April 20th low, WTI oil prices have rebounded and averaged $43 per barrel during the fourth-quarter 2020 and averaged $54 per barrel during the first-quarter 2021 through mid-February.

We maintain an active, multi-year commodity derivatives strategy to minimize commodity price volatility and support cash flows needed for operations. For 2021, we currently have oil derivatives in place for 8.1 million barrels at a weighted-average floor price of $50.83 Brent per barrel. For 2022, we currently have oil derivatives in place for 3.8 million barrels swapped at a weighted-average price of $47.05 Brent per barrel.

For 2021, we currently expect to operate two drilling rigs and one completions crew and capital expenditures to be approximately $360 million. However, we will continue to monitor commodity prices and service costs and adjust activity levels in order to proactively manage our cash flows and preserve liquidity.

Pricing and reserves

Our results of operations are heavily influenced by oil, NGL and natural gas prices, and although prices have stabilized, they remained at low levels in fourth-quarter 2020 for oil and NGL. Oil, NGL and natural gas price fluctuations continue to be impacted by the COVID-19 pandemic and policies of OPEC+, which have generally increased supply, decreased demand, made economic and market conditions more volatile, caused transportation and storage constraints and led to a variety of additional issues on both a regional and global basis. Historically, commodity prices have experienced significant fluctuations; however, the volatility in the prices has substantially increased as a result of world developments in 2020. The duration of such developments may affect the economic viability of, and our ability to fund our drilling projects, as well as the economic valuation and economic recovery of oil, NGL and natural gas reserves. See "Critical accounting estimates" for further discussion of our oil, NGL and natural gas reserve quantities and standardized measure of discounted future net cash flows.

We have entered into a number of commodity derivative contracts that have enabled us to offset a portion of the changes in our cash flow caused by fluctuations in price and basis differentials for our sales of oil, NGL and natural gas, as discussed in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk." See Notes 10.a, 11.a and 19.b to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our commodity derivatives, including transactions subsequent to December 31, 2020.

Our reserves are reported in three streams: oil, NGL and natural gas. The Realized Prices utilized to value our proved reserves as of December 31, 2020 and 2019, are as follows:

	December 31, 2020	December 31, 2019
Realized Prices:		
Oil ($/Bbl)	$ 37.69	$ 52.12
NGL ($/Bbl)	$ 7.43	$ 12.21
Natural gas ($/Mcf)	$ 0.79	$ 0.53

The Realized Prices used to estimate proved reserves do not include derivative transactions. The unamortized cost of evaluated oil and natural gas properties being depleted exceeded the full cost ceiling for each of the quarterly periods in 2020 and for the third and fourth quarters of 2019 and, as such, we recorded non-cash full cost ceiling impairments of $889.5 million and $620.6 million during the years ended December 31, 2020 and 2019, respectively. As more specifically addressed in "Hypothetical first-quarter 2021 full cost ceiling calculation" below, if prices remain at the current levels, subject to numerous factors and inherent limitations, and all other factors remain constant, a non-cash full cost ceiling impairment in the first-quarter 2021 is not implied. See Notes 2.g and 6.a to our consolidated financial statements included elsewhere in this Annual Report for discussion of the full cost method of accounting and our Realized Prices.

Horizontal drilling of unconventional wells using enhanced completions techniques, including, but not limited to, hydraulic fracturing, is a relatively new process and, as such, forecasting the long-term production of such wells is inherently uncertain and subject to varying interpretations. As we receive and process geological and production data from these wells over time, we analyze such data to confirm whether previous assumptions regarding original forecasted production, inventory and reserves continue to appear accurate or require modification. While all production forecasts have elements of uncertainty over the life of the related wells, we have observed over multiple years that oil decline rates are impacted by the vertical and horizontal spacing of wells. In 2020, all wells drilled and completed in our established acreage and Western Glasscock were executed at the wider spacing to mitigate this effect. Wells in Howard County were completed at various horizontal spacing patterns as we test the optimum spacing in that area. In order to mitigate potential negative revisions in future years, we have taken a conservative approach in regards to oil rate forecasts on future wells in Howard County.

Initial production results, production decline rates, well density, completions design and operating method are examples of the numerous uncertainties and variables inherent in the estimation of proved reserves in future periods. The quantity of proved reserves is one of the many variables inherent in the calculation of depletion. See "Costs and expenses" below for additional information of depletion expense.

Hypothetical first-quarter 2021 full cost ceiling calculation

We use the full cost method of accounting for our oil and natural gas properties, with the full cost ceiling, as defined by the SEC, based principally on the estimated future net cash flows from our proved oil, NGL and natural gas reserves, which exclude the effect of our commodity derivative transactions, discounted at 10% under required SEC guidelines for pricing methodology. We review the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC on a quarterly basis. In the event the unamortized cost, or net book value, of evaluated oil and natural gas properties being depleted exceeds the full cost ceiling, the excess is expensed in the period such excess occurs. Once incurred, a write-down of evaluated oil and natural gas properties is not reversible.

If prices remain at the current levels, subject to numerous factors and inherent limitations, some of which are discussed below, and all other factors remain constant, a non-cash full cost ceiling impairment in first-quarter 2021 is not implied.

There are numerous uncertainties inherent in the estimation of proved reserves and accounting for oil and natural gas properties in future periods. In addition to unknown future commodity prices, other uncertainties include, but are not limited to (i) changes in drilling and completions costs, (ii) changes in oilfield service costs, (iii) production results, (iv) our ability, in a low price environment, to strategically drill the most economic locations in our multi-level horizontal targets, (v) potential government imposed curtailment of production, (vi) potential necessity to shut-in a portion or all of our wells, (vii) income tax impacts, (viii) potential recognition of additional proved undeveloped reserves, (ix) any potential value added to our proved reserves when testing recoverability from drilling unbooked locations, (x) revisions to production curves based on additional data and (xi) inherent significant volatility in the commodity prices for oil, NGL and natural gas.

Each of the above factors is evaluated on a quarterly basis and if there is a material change in any factor it is incorporated into our reserves estimation utilized in our quarterly accounting estimates. We use our reserve estimates to evaluate, also on a quarterly basis, the reasonableness of our resource development plans for our reported proved reserves. Changes in circumstance, including commodity pricing, economic factors and the other uncertainties described above may lead to changes in our development plans.

Below is the hypothetical first-quarter 2021 full cost ceiling calculation. This should not be interpreted to be indicative of our development plan or of our actual future results. Each of the uncertainties noted above has been evaluated for material known trends to be potentially included in the estimation of possible first-quarter 2021 effects. Based on such review, we determined that commodity prices are the only significant known variable necessary in calculating the following scenario.

Our hypothetical first-quarter 2021 full cost ceiling calculation has been prepared by substituting (i) $37.56 per Bbl for oil, (ii) $9.77 per Bbl for NGL and (iii) $1.22 per Mcf for natural gas (collectively, the "Pro Forma First-Quarter Prices") for the respective Realized Prices as of December 31, 2020. All other inputs and assumptions have been held constant. Accordingly, this estimation strictly isolates the estimated impact of commodity prices on the first-quarter 2021 Realized Prices that will be utilized in our full cost ceiling calculation. The Pro Forma First-Quarter Prices use a slightly modified Realized Price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for oil, NGL and natural gas for the 11 months ended February 1, 2021 and holding the February 1, 2021 prices constant for the remaining twelfth month of the calculation. Based solely on the substitution of the Pro Forma First-Quarter Prices into our December 31, 2020 proved reserve estimates, there would be no implied first-quarter 2021 impairment. We believe that substituting these prices into our December 31, 2020 proved reserve estimates may help provide users with an understanding of the potential impact on our first-quarter 2021 full cost ceiling test.

Results of operations

Revenues

Sources of our revenue

Our revenues are derived from the sale of produced oil, NGL and natural gas, the sale of purchased oil and providing midstream services to third parties, all within the continental U.S. and do not include the effects of derivatives. See Notes 2.n and 14 to our consolidated financial statements included elsewhere in this Annual Report below for additional information regarding our revenue recognition policies.

The following table presents our sources of revenue as a percentage of total revenues for the periods presented and corresponding changes:

	Years ended December 31,		2020 compared to 2019	
	2020	2019	Change (#)	Change (%)
Oil sales	55 %	68 %	(13)%	(19)%
NGL sales	12 %	12 %	— %	— %
Natural gas sales	7 %	4 %	3 %	75 %
Midstream service revenues	1 %	2 %	(1)%	(50)%
Sales of purchased oil	25 %	14 %	11 %	79 %
Total	100 %	100 %		

Table of Contents

Oil, NGL and natural gas sales volumes, revenues and prices

The following table presents information regarding our oil, NGL and natural gas sales volumes, sales revenues and average sales prices for the periods presented and corresponding changes:

	Years ended December 31,		2020 compared to 2019	
	2020	2019	Change (#)	Change (%)
Sales volumes:				
Oil (MBbl)	9,827	10,376	(549)	(5)%
NGL (MBbl)	10,615	9,118	1,497	16 %
Natural gas (MMcf)	70,049	60,169	9,880	16 %
Oil equivalents (MBOE)[1][2]	32,117	29,522	2,595	9 %
Average daily oil equivalent sales volumes (BOE/D)[2]	87,750	80,883	6,867	8 %
Average daily oil sales volumes (Bbl/D)[2]	26,849	28,429	(1,580)	(6)%
Sales revenues (in thousands):				
Oil	$ 367,792	$ 572,918	$ (205,126)	(36)%
NGL	78,246	100,330	(22,084)	(22)%
Natural gas	50,317	33,300	17,017	51 %
Total oil, NGL and natural gas sales revenues	$ 496,355	$ 706,548	$ (210,193)	(30)%
Average sales prices[2]:				
Oil ($/Bbl)[3]	$ 37.43	$ 55.21	$ (17.78)	(32)%
NGL ($/Bbl)[3]	$ 7.37	$ 11.00	$ (3.63)	(33)%
Natural gas ($/Mcf)[3]	$ 0.72	$ 0.55	$ 0.17	31 %
Average sales price ($/BOE)[3]	$ 15.45	$ 23.93	$ (8.48)	(35)%
Oil, with commodity derivatives ($/Bbl)[4]	$ 56.41	$ 54.37	$ 2.04	4 %
NGL, with commodity derivatives ($/Bbl)[4]	$ 9.12	$ 13.61	$ (4.49)	(33)%
Natural gas, with commodity derivatives ($/Mcf)[4]	$ 1.02	$ 1.05	$ (0.03)	(3)%
Average sales price, with commodity derivatives ($/BOE)[4]	$ 22.50	$ 25.45	$ (2.95)	(12)%

(1) BOE is calculated using a conversion rate of six Mcf per one Bbl.

(2) The numbers presented in the years ended December 31, 2020 and 2019 columns are based on actual amounts and are not calculated using the rounded numbers presented in the table above or the table below.

(3) Price reflects the average of actual sales prices received when control passes to the purchaser/customer adjusted for quality, certain transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the delivery point.

(4) Price reflects the after-effects of our commodity derivative transactions on our average sales prices. Our calculation of such after-effects includes settlements of matured commodity derivatives during the respective periods in accordance with GAAP and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to commodity derivatives that settled during the respective periods.

The following table presents settlements received for matured commodity derivatives and premiums paid previously or upon settlement attributable to commodity derivatives that matured during the periods utilized in our calculation of the average sales prices, with commodity derivatives, for the periods presented and corresponding changes:

	Years ended December 31,		2020 compared to 2019	
(in thousands)	**2020**	**2019**	**Change ($)**	**Change (%)**
Settlements received for matured commodity derivatives:				
Oil	$ 188,594	$ 9,539	$ 179,055	1,877 %
NGL	18,553	23,749	(5,196)	(22)%
Natural gas	21,147	29,933	(8,786)	(29)%
Total	$ 228,294	$ 63,221	$ 165,073	261 %
Premiums paid previously or upon settlement attributable to commodity derivatives that matured during the respective period:				
Oil	$ (2,087)	$ (18,323)	$ 16,236	89 %

Changes in average sales prices and sales volumes caused the following changes to our oil, NGL and natural gas revenues between the years ended December 31, 2020 and 2019:

(in thousands)	**Oil**	**NGL**	**Natural gas**	**Total**
2019 Revenues	$ 572,918	$ 100,330	$ 33,300	$ 706,548
Effect of changes in average sales prices	(174,768)	(38,562)	11,549	(201,781)
Effect of changes in sales volumes	(30,358)	16,478	5,468	(8,412)
2020 Revenues	$ 367,792	$ 78,246	$ 50,317	$ 496,355
Change ($)	$ (205,126)	$ (22,084)	$ 17,017	$ (210,193)
Change (%)	(36)%	(22)%	51 %	(30)%

Beginning in March 2020, we experienced significant decreases in oil, NGL and natural gas sales prices related to actions of OPEC+ and COVID-19. As a result of this sharp decline in commodity prices, we reduced completions activity earlier in the year and our oil sales volumes decreased. Since then, oil, NGL and natural gas sales prices have stabilized and recovered to some degree, but are continuing to exhibit high volatility. With oil prices currently stabilized, we added completions activity during fourth-quarter 2020 and we expect to see the results of these additions in first-quarter 2021 volumes. The increases in NGL and natural gas sales volumes are related to our last wells completed prior to our reduced completions activity earlier in the year. In general, oil production declines at a faster rate than natural gas production.

The following table presents midstream service and sales of purchased oil revenues for the periods presented and corresponding changes:

	Years ended December 31,		2020 compared to 2019	
(in thousands)	**2020**	**2019**	**Change ($)**	**Change (%)**
Midstream service revenues	$ 8,249	$ 11,928	$ (3,679)	(31)%
Sales of purchased oil	$ 172,588	$ 118,805	$ 53,783	45 %

Midstream service revenues

Our midstream service revenues decreased for the year ended December 31, 2020 compared to 2019. Midstream service revenues are generated by oil throughput fees and services provided to third parties for (i) integrated oil and natural gas gathering and transportation systems and related facilities, (ii) natural gas lift, fuel for drilling and completions activities and centralized compression infrastructure and (iii) water storage, recycling and transportation infrastructure and are recognized over time as the customer benefits from these services when provided.

Sales of purchased oil

Sales of purchased oil increased for the year ended December 31, 2020 compared to 2019. These revenues are a function of the volumes and prices of purchased oil sold to customers and are offset by the volumes and costs of purchased oil. We are a firm shipper on both the Bridgetex and Gray Oak pipelines, the latter of which we began shipment on during fourth-quarter 2019, and we utilize purchased oil to fulfill portions of our commitments. We anticipate continuing this practice in the future.

We enter into purchase transactions with third parties and separate sale transactions. These transactions are presented on a gross basis as we act as the principal in the transaction by assuming control of the commodities purchased and the responsibility to deliver the commodities sold. Revenue is recognized when control transfers to the purchaser/customer at the delivery point based on the price received. The transportation costs associated with these transactions are presented as a component of costs of purchased oil. See "—Costs and expenses - Costs of purchased oil."

Costs and expenses

Costs and expenses and average costs and expenses per BOE sold

The following table presents information regarding costs and expenses and selected average costs and expenses per BOE sold for the periods presented and corresponding changes:

	Years ended December 31,		2020 compared to 2019	
(in thousands except for per BOE sold data)	**2020**	**2019**	**Change ($)**	**Change (%)**
Costs and expenses:				
Lease operating expenses	$ 82,020	$ 90,786	$ (8,766)	(10)%
Production and ad valorem taxes	33,050	40,712	(7,662)	(19)%
Transportation and marketing expenses	49,927	25,397	24,530	97 %
Midstream service expenses	3,762	4,486	(724)	(16)%
Costs of purchased oil	194,862	122,638	72,224	59 %
General and administrative (excluding LTIP)	41,538	48,128	(6,590)	(14)%
General and administrative (LTIP):				
LTIP cash	1,802	—	1,802	100 %
LTIP non-cash	7,194	6,601	593	9 %
Organizational restructuring expenses	4,200	16,371	(12,171)	(74)%
Depletion, depreciation and amortization	217,101	265,746	(48,645)	(18)%
Impairment expense	899,039	620,889	278,150	45 %
Other operating expenses	4,430	4,118	312	8 %
Total costs and expenses	$ 1,538,925	$ 1,245,872	$ 293,053	24 %
Selected average costs and expenses per BOE sold[(1)]				
Lease operating expenses	$ 2.55	$ 3.08	$ (0.53)	(17)%
Production and ad valorem taxes	1.03	1.38	(0.35)	(25)%
Transportation and marketing expenses	1.55	0.86	0.69	80 %
Midstream service expenses	0.12	0.15	(0.03)	(20)%
General and administrative (excluding LTIP)	1.29	1.63	(0.34)	(21)%
Total selected operating expenses	$ 6.54	$ 7.10	$ (0.56)	(8)%
General and administrative (LTIP):				
LTIP cash	$ 0.06	$ —	$ 0.06	100 %
LTIP non-cash	$ 0.22	$ 0.22	$ —	— %
Depletion, depreciation and amortization	$ 6.76	$ 9.00	$ (2.24)	(25)%

(1) Selected average costs and expenses per BOE sold are based on actual amounts and are not calculated using the rounded numbers presented in the table above.

Lease operating expenses ("LOE")

LOE and LOE per BOE sold both decreased for the year ended December 31, 2020 compared to 2019. LOE are daily costs incurred to bring oil, NGL and natural gas out of the ground and to market, together with the daily costs incurred to maintain our producing properties. Such costs also include maintenance, repairs and non-routine workover expenses related to our oil and natural gas properties. We continue to focus on economic efficiencies associated with the usage and procurement of products and services related to LOE and decreasing failures and related workover expenses. We expect LOE to increase in 2021 due to higher expected operating costs on the wells coming on line in Howard County compared to operating costs on our established acreage.

Production and ad valorem taxes

Production and ad valorem taxes decreased for the year ended December 31, 2020 compared to 2019. Production taxes are based on and fluctuate in proportion to our oil, NGL and natural gas sales revenues, and are established by federal, state or local taxing authorities. We take full advantage of all credits and exemptions in our various taxing jurisdictions. Ad valorem taxes are based on and fluctuate in proportion to the taxable value assessed by the various counties where our oil and natural gas properties are located.

Transportation and marketing expenses

Transportation and marketing expenses increased for the year ended December 31, 2020 compared to 2019. These are costs incurred for the delivery of produced oil to customers in the U.S. Gulf Coast market via the Bridgetex pipeline and the Gray Oak pipeline. We began shipment on the Gray Oak pipeline during the fourth quarter of 2019. We plan to ship the majority of our produced oil to the U.S. Gulf Coast, which we believe provides a long-term pricing advantages versus the Midland market. Additionally, firm transportation payments on excess pipeline capacity associated with transportation agreements are included in transportation and marketing expenses. For the year ended December 31, 2020, we expensed firm transportation payments on excess capacity of $4.0 million related to a transportation commitment with a certain pipeline pertaining to the gathering of our production from our established acreage that extends into 2024. See "—Obligations and commitments" and Note 16.c to our consolidated financial statements included elsewhere in this Annual Report for information regarding our transportation commitments. Additionally, we recognized marketing expense due to negative natural gas prices in March 2020.

Midstream service expenses

Midstream service expenses decreased for the year ended December 31, 2020 compared to 2019. These are costs incurred to operate and maintain our (i) integrated oil and natural gas gathering and transportation systems and related facilities (ii) centralized oil storage tanks, (iii) natural gas lift, fuel for drilling and completions activities and centralized compression infrastructure and (iv) water storage, recycling and transportation facilities.

Costs of purchased oil

Costs of purchased oil increased for the year ended December 31, 2020 compared to 2019. We are a firm shipper on both the Bridgetex and Gray Oak pipelines, the latter of which we began shipment on during fourth-quarter 2019, and we utilize purchased oil to fulfill portions of our commitments. In the event our long-haul transportation capacity on the Bridgetex pipeline and Gray Oak pipeline exceeds our net production, consistent with our historic practice, we expect to continue to purchase third-party oil at the trading hubs to satisfy the deficit in our associated long-haul transportation commitments.

General and administrative ("G&A")

G&A, excluding employee compensation expense from our long-term incentive plan ("LTIP"), decreased for the year ended December 31, 2020, compared to 2019, mainly due to decreases in employee-related costs as a result of the cumulative measures taken during 2020 and 2019 to align our cost structure with operational activity, which included workforce reductions.

LTIP cash expense increased for the year ended December 31, 2020, compared to 2019, as these types of cash awards were not in place in 2019. LTIP non-cash expense increased for the year ended December 31, 2020 compared to 2019, but did not change on a per BOE basis. See Notes 2.p, 9.a and 18 to our consolidated financial statements included elsewhere in this Annual Report for information regarding our equity-based compensation.

G&A are costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, non-production based franchise taxes, audit and other fees for professional services, legal compliance and equity-based compensation.

Organizational restructuring expenses

Organizational restructuring expenses are related to our workforce reductions and senior officer retirements in an effort to reduce costs and better position ourselves for the future in response to market condition. We incurred one-time charges comprised of compensation, taxes, professional fees, outplacement and insurance-related expenses during the years ended December 31, 2020 and 2019. As of December 31, 2020, no additional organizational restructuring expenses are expected to be incurred. See Note 18 to our consolidated financial statements included elsewhere in this Annual Report for further discussion of the organizational restructurings.

Other operating expenses

These costs include accretion expense due to the passage of time on our asset retirement obligations. See Note 2.k to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our asset retirement obligations and "Critical accounting estimates".

Depletion, depreciation and amortization ("DD&A")

The following table presents the components of our DD&A for the periods presented and corresponding changes:

	Years ended December 31,		2020 compared to 2019	
(in thousands)	2020	2019	Change ($)	Change (%)
Depletion of evaluated oil and natural gas properties	$ 203,492	$ 250,857	$ (47,365)	(19)%
Depreciation of midstream service assets	9,838	10,206	(368)	(4)%
Depreciation and amortization of other fixed assets	3,771	4,683	(912)	(19)%
Total DD&A	$ 217,101	$ 265,746	$ (48,645)	(18)%

DD&A decreased for the year ended December 31, 2020 compared to 2019. Depletion expense per BOE decreased by $2.16, or 25%, for the year ended December 31, 2020 compared to 2019. Depletion expense decreased as a result of the full cost impairments incurred during first-quarter 2020, second-quarter 2020 and third-quarter 2020, and we expect depletion expense to further decrease in first-quarter 2021 due to the fourth-quarter 2020 impairment.

See Notes 2.g and 6.a to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding the full cost method of accounting.

Impairment expense

The following table presents the components of our impairment expense for the periods presented and corresponding changes:

	Years ended December 31,		2020 compared to 2019	
(in thousands)	2020	2019	Change ($)	Change (%)
Full cost ceiling impairment expense	$ 889,453	$ 620,565	$ 268,888	43 %
Midstream service asset impairment expense	8,183	—	8,183	100 %
Line-fill and other inventories impairment expense	1,403	324	1,079	333 %
Total impairment expense	$ 899,039	$ 620,889	$ 278,150	45 %

The unamortized cost of evaluated oil and natural gas properties being depleted exceeded the full cost ceiling for each of the quarterly periods in 2020 and for the third and fourth quarters of 2019 and, as such, we recorded non-cash full cost ceiling impairments of $889.5 million and $620.6 million during the years ended December 31, 2020 and 2019, respectively. See Note 6.a to our consolidated financial statements included elsewhere in this Annual Report and see "—Pricing and reserves" for additional discussion of full cost ceiling impairments.

Impairments are recorded on long-lived assets when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying amount. Impairment is measured based on the

excess of the carrying amount over the fair value of the asset. All inventory is carried at the lower of cost or net realizable value ("NRV"), with cost determined using the weighted-average cost method. See Notes 2.i and 11.b to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our inventory and long-lived assets.

Non-operating income (expense)

The following table presents the components of non-operating income (expense), net for the periods presented and corresponding changes:

	Years ended December 31,		2020 compared to 2019	
(in thousands)	2020	2019	Change ($)	Change (%)
Gain on derivatives, net	$ 80,114	$ 79,151	$ 963	1 %
Interest expense	(105,009)	(61,547)	(43,462)	(71)%
Litigation settlement	—	42,500	(42,500)	(100)%
Gain on extinguishment of debt, net	8,989	—	8,989	100 %
Loss on disposal of assets, net	(963)	(248)	(715)	(288)%
Write-off of debt issuance costs	(1,103)	(935)	(168)	(18)%
Other income, net	1,586	4,623	(3,037)	(66)%
Total non-operating income (expense), net	$ (16,386)	$ 63,544	$ (79,930)	(126)%

Gain on derivatives, net

The following table presents the components of gain on derivatives, net for the periods presented and corresponding changes:

	Years ended December 31,		2020 compared to 2019	
(in thousands)	2020	2019	Change ($)	Change (%)
Non-cash gain (loss) on derivatives, net	$ (103,377)	$ 30,402	$ (133,779)	(440)%
Settlements received for matured derivatives, net	228,221	63,221	165,000	261 %
Settlements received (paid) for early-terminated commodity derivatives, net	6,340	(5,409)	11,749	217 %
Premiums paid for commodity derivatives	(51,070)	(9,063)	(42,007)	(463)%
Gain on derivatives, net	$ 80,114	$ 79,151	$ 963	1 %

Non-cash gain (loss) on derivatives, net is the result of (i) new, matured and early-terminated contracts, including contingent consideration derivatives for the period subsequent to the acquisition date and through the end of the contingency period, and the changing relationship between our outstanding contract prices and the future market prices in the forward curves, which we use to calculate the fair value of our commodity and contingent derivatives and (ii) new interest rate swaps and the changing relationship between the contract interest rate and the LIBOR interest rate forward curve. In general, if outstanding commodity contracts are held constant, we experience gains during periods of decreasing market prices and losses during periods of increasing market prices.

Settlements received or paid for matured derivatives are for our commodity derivative contracts, which are based on the settlement prices compared to the prices specified in the contracts, and for our interest rate derivative contract.

During the year ended December 31, 2020, we completed hedge restructurings by (i) early terminating collars and entering into new swaps and (ii) early terminating swaps. Additionally, we entered into 2021 puts during the year ended December 31, 2020 and paid $50.6 million in premiums to increase the put price received.

We classify these gains and losses as operating activities in our consolidated statements of cash flows. See Notes 2.e, 4, 10 11.a and 19.b to our consolidated financial statements included elsewhere in this Annual Report and see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" below for additional information regarding our derivatives.

Interest expense

Interest expense increased for the year ended December 31, 2020 compared to 2019 mainly due to the issuance of our January 2025 Notes and January 2028 Notes, partially offset by our repurchase of a portion of these notes and the extinguishment of our January 2022 Notes and March 2023 Notes, resulting in an increase in the carrying amount of long-term debt along with higher fixed interest rates.

We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our Senior Secured Credit Facility and our senior unsecured notes. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to the lenders and bondholders in interest expense, net of amounts capitalized. In addition, we include the amortization of: (i) debt issuance costs (including origination, amendment and professional fees), (ii) deferred premiums associated with our commodity derivative contracts, (iii) commitment fees and (iv) annual agency fees in interest expense. See Note 7 to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our debt and interest expense.

Litigation settlement

During the year ended December 31, 2019, we finalized and received a favorable settlement of $42.5 million in connection with our damage claims asserted in a previously disclosed litigation matter relating to a breach and wrongful termination of a crude oil purchase agreement. We do not anticipate receiving further payments in connection with this matter as this settlement constituted a full and final satisfaction of our claims. For further discussion of the litigation settlement proceeds, see Note 16.a to our consolidated financial statements included elsewhere in this Annual Report.

Gain on extinguishment of debt, net

During the year ended December 31, 2020, we recognized a (i) loss on extinguishment of debt of $13.3 million related to the difference between the consideration for tender offers, early tender premiums and redemption prices and the net carrying amounts of the extinguished January 2022 Notes and March 2023 Notes and (ii) a gain on extinguishment of debt of $22.3 million related to the difference between the consideration paid and the net carrying amounts of the extinguished portions of the January 2025 Notes and January 2028 Notes. See Notes 7.a, 7.b to our consolidated financial statements included elsewhere in this Annual Report for additional information of our extinguishments of debt.

Loss on disposal of assets, net

Loss on disposal of assets, net, increased for the year ended December 31, 2020 compared to 2019. From time to time, we dispose of inventory, midstream service assets and other fixed assets. The associated gain or loss recorded during the period fluctuates depending upon the volume of the assets disposed, their associated net book value and, in the case of a disposal by sale, the sale price.

Write-off of debt issuance costs

We wrote off $1.1 million and $0.9 million of debt issuance costs during the years ended December 31, 2020 and 2019, respectively, as a result of decreases in the borrowing base and aggregate elected commitment of the Senior Secured Credit Facility.

Debt issuance costs, which are stated at cost, net of amortization, are amortized over the life of the respective debt agreements utilizing the effective interest and straight-line methods. Write-offs of such costs can occur when borrowing terms decrease on our Senior Secured Credit Facility. Write-offs related to our senior unsecured notes occur when the notes have been extinguished and are included in "Gain on extinguishment of debt, net". See Note 7.d to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our debt issuance costs.

Other income, net

This represents the interest received on our cash and cash equivalents and sublease income as well as other miscellaneous income. See Note 5.b to our consolidated financials statements included elsewhere in this Annual Report for additional information regarding our sublease income.

Income tax benefit

The following table presents income tax benefit for the periods presented and corresponding changes:

	Years ended December 31,		2020 compared to 2019	
(in thousands)	2020	2019	Change ($)	Change (%)
Deferred	3,946	2,588	1,358	52 %

We are subject to federal and Oklahoma corporate income taxes and the Texas franchise tax. The deferred income tax benefit for the periods presented is attributed to deferred Texas franchise tax. As of December 31, 2020, we determined it was more likely than not that our federal and Oklahoma net deferred tax assets were not realizable through future net income. As of December 31, 2020, a total valuation allowance of $489.1 million has been recorded to offset our federal and Oklahoma net deferred tax assets, resulting in a Texas net deferred tax asset of $1.5 million. The effective tax rate was not meaningful for the periods presented and we expect it to remain under 1%, due to the full valuation allowance against the Company's federal and Oklahoma net deferred tax assets. For additional discussion of our income taxes, see Note 13 to our consolidated financial statements included elsewhere in this Annual Report and "Critical accounting estimates".

Liquidity and capital resources

In light of the world developments in 2020, we continue to closely monitor our capital resources and business plans. Historically, our primary sources of liquidity have been cash flows from operations, proceeds from equity offerings, proceeds from senior unsecured note offerings, borrowings under our Senior Secured Credit Facility and proceeds from asset dispositions. While we cannot predict the duration and negative impact of COVID-19 and OPEC+ actions on the energy industry, we believe our cash flows from operations, hedges and availability under our Senior Secured Credit Facility provide sufficient liquidity to manage our cash needs and contractual obligations and to fund our expected capital expenditures. Our primary operational uses of capital have been for the acquisition, exploration and development of oil and natural gas properties and infrastructure development.

We continually monitor the markets and consider which financing alternatives, including debt and equity capital resources, joint ventures and asset sales, are available to meet our future planned capital expenditures, a significant portion of which we are able to adjust and manage. We also continually evaluate opportunities with respect to our capital structure, including issuances of new securities, as well as transactions involving our outstanding senior notes, which could take the form of open market or private repurchases, exchange or tender offers, or other similar transactions, and our common stock, which could take the form of open market or private repurchases. We may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity and/or achieving cost efficiency. Such financing alternatives, or combination of alternatives, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. We continuously look for other opportunities to maximize shareholder value.

Due to the inherent volatility in oil, NGL and natural gas prices and differences in the prices of oil, NGL and natural gas between where we produce and where we sell such commodities, we engage in commodity derivative transactions, such as puts, swaps, collars and basis swaps to hedge price risk associated with a portion of our anticipated sales volumes. Due to the inherent volatility in interest rates, we have entered into an interest rate derivative swap to hedge interest rate risk associated with a portion of our anticipated outstanding debt under the Senior Secured Credit Facility. We will pay a fixed rate over the contract term for that portion. By removing a portion of the (i) price volatility associated with future sales volumes and (ii) interest rate volatility associated with anticipated outstanding debt, we expect to mitigate, but not eliminate, the potential effects of variability in cash flows from operations. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" below. See Notes 10.a, 10.b and 19.b to our consolidated financial statements included elsewhere in this Annual Report for discussion of our (i) commodity derivatives and a summary of open commodity derivative positions as of December 31, 2020 for commodity derivatives that were entered into through December 31, 2020, (ii) interest rate derivative and (iii) subsequent commodity derivative activity and a summary of our resulting open oil and natural gas derivative positions as of December 31, 2020 for derivative transactions through February 19, 2021, respectively.

We continually seek to maintain a financial profile that provides operational flexibility. As of December 31, 2020, we had cash and cash equivalents of $48.8 million and available capacity under the Senior Secured Credit Facility, after the reduction for outstanding letters of credit, of $425.9 million, resulting in total liquidity of $474.7 million. As of February

22, 2021, we had cash and cash equivalents of $47 million and available capacity under the Senior Secured Credit Facility, after the reduction for outstanding letters of credit, of $430.9 million, resulting in total liquidity of $477.9 million. We believe that our operating cash flows and the aforementioned liquidity sources provide us with the financial resources to manage our business needs, to implement our planned capital expenditure budget and, at our discretion, pay down, repurchase or refinance debt or adjust our planned capital expenditure budget.

Cash flows

The following table presents our cash flows for the periods presented and corresponding changes:

	Years ended December 31,		2020 compared to 2019	
(in thousands)	**2020**	**2019**	**Change ($)**	**Change (%)**
Net cash provided by operating activities	$ 383,390	$ 475,074	$ (91,684)	(19)%
Net cash used in investing activities	(389,238)	(661,711)	272,473	41 %
Net cash provided by financing activities	13,748	182,343	(168,595)	(92)%
Net increase (decrease) in cash and cash equivalents	$ 7,900	$ (4,294)	$ 12,194	284 %

Cash flows from operating activities

Net cash provided by operating activities decreased during the year ended December 31,2020, compared to 2019. Notable changes include (i) a decrease in total oil, NGL and natural gas sales revenues of $210.2 million, (ii) an increase of $134.7 million in net settlements received for matured and early-terminated derivatives, net of premiums paid, mainly due to decreases in commodity prices, (iii) an increase of $86.2 million in net changes in operating assets and liabilities and (iv) a decrease in non-recurring litigation proceeds of $42.5 million. Other significant changes are (i) increases in interest expense, costs of purchased oil partially offset by sales of purchased oil and transportation and marketing expenses, and (ii) decreases in LOE, production and ad valorem taxes, G&A and organizational restructuring expenses. The decrease in total oil, NGL and natural gas sales revenues is due to a 35% decrease in average sales price per BOE and was partially offset by a 9% increase in total volumes sold. See "—Results of operations" for additional discussion of our oil, NGL and natural gas sales revenues, derivatives and expenses.

Our operating cash flows are sensitive to a number of variables, the most significant of which are the volatility of oil, NGL and natural gas prices, mitigated to the extent of our commodity derivatives' exposure, and sales volume levels. Regional and worldwide economic activity, weather, infrastructure, transportation capacity to reach markets, costs of operations, legislation and regulations, including potential government production curtailments, and other variable factors significantly impact the prices of these commodities. Commodity prices have been most impacted by the effects of COVID-19 on demand and the effects of the OPEC+ actions, and earlier in the year, related transportation and storage constraints, particularly in the State of Texas, on supply. These factors are not within our control and are difficult to predict. For additional information on risks related to our business, see "Part I. Item 1A. Risk Factors" included elsewhere in this Annual Report.

Cash flows from investing activities

Net cash used in investing activities decreased during the year ended December 31, 2020, compared to 2019, mainly due to decreases in acquisitions of oil and natural gas properties and capital expenditures for oil and natural gas properties. See Note 4 to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our acquisitions of oil and natural gas properties.

The following table presents the components of our cash flows from investing activities for the periods presented and corresponding changes:

	Years ended December 31,		2020 compared to 2019	
(in thousands)	2020	2019	Change ($)	Change (%)
Acquisitions of oil and natural gas properties	$ (35,786)	$ (199,284)	$ 163,498	82 %
Capital expenditures:				
Oil and natural gas properties	(347,359)	(458,985)	111,626	24 %
Midstream service assets	(3,171)	(7,910)	4,739	60 %
Other fixed assets	(4,259)	(2,433)	(1,826)	(75)%
Proceeds from dispositions of capital assets, net of selling costs	1,337	6,901	(5,564)	(81)%
Net cash used in investing activities	$ (389,238)	$ (661,711)	$ 272,473	41 %

Expected capital expenditures

Our capital spending in 2020 has been influenced by commodity price changes, production levels and, among other factors, changes in service costs and drilling and completions efficiencies. In early 2020, we significantly reduced planned operational activities as commodity prices suffered from historic declines due to actions of OPEC+ and COVID-19, dramatically reducing expected returns on capital investments. A subsequent increase in commodity prices, paired with service cost reductions, has driven expected returns on our Howard County acreage back to levels that support a resumption of completions activity and, beginning in September 2020, we began operating a completions crew in Howard County. We currently expect capital expenditures for 2021 to be approximately $360 million. We are prepared to adjust our capital expenditures further if oil, NGL and natural gas prices continue to exhibit volatility. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted.

The following table presents the components of our costs incurred, excluding non-budgeted acquisition costs, for the periods presented and corresponding changes:

	Years ended December 31,		2020 compared to 2019	
(in thousands)	2020	2019	Change ($)	Change (%)
Oil and natural gas properties[1]	$ 344,160	$ 470,455	$ (126,295)	(27)%
Midstream service assets	2,985	8,655	(5,670)	(66)%
Other fixed assets	4,148	2,470	1,678	68 %
Total costs incurred, excluding non-budgeted acquisition costs	$ 351,293	$ 481,580	$ (130,287)	(27)%

(1) See Note 20.a to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our costs incurred in the exploration and development of oil and natural gas properties.

The amount, timing and allocation of capital expenditures are largely discretionary and within management's control. If oil, NGL and natural gas prices are below our acceptable levels, or costs are above our acceptable levels, we may choose to defer a portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flow. Subject to financing alternatives, we may also increase our capital expenditures significantly to take advantage of opportunities we consider to be attractive. We continually monitor and may adjust our projected capital expenditures in response to world developments, such as those we experienced in 2020, as well as success or lack of success in drilling activities, changes in prices, availability of financing and joint venture opportunities, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs and supplies, changes in service costs, contractual obligations, internally generated cash flow and other factors both within and outside our control.

Cash flows from financing activities

Net cash provided by financing activities decreased during the year ended December 31, 2020, compared to 2019. Notable changes include the issuance of our January 2025 Notes and January 2028 Notes, partially offset by (i) the extinguishment of our January 2022 Notes and March 2023 Notes, (ii) the repurchase of portions of our January 2025 Notes and January 2028

Notes under our bond repurchase program and (iii) borrowings and payments on our Senior Secured Credit Facility. For further discussion of our financing activities related to debt instruments, see Notes 7 and 19.a to our consolidated financial statements included elsewhere in this Annual Report.

The following table presents the components of our cash flows from financing activities for the periods presented and corresponding changes:

(in thousands)	Years ended December 31, 2020	2019	2020 compared to 2019 Change ($)	Change (%)
Borrowings on Senior Secured Credit Facility	$ 80,000	$ 275,000	$ (195,000)	(71)%
Payments on Senior Secured Credit Facility	(200,000)	(90,000)	(110,000)	(122)%
Issuance of January 2025 Notes and January 2028 Notes	1,000,000	—	1,000,000	100 %
Extinguishment of debt	(846,994)	—	(846,994)	(100)%
Stock exchanged for tax withholding	(779)	(2,657)	1,878	71 %
Payments for debt issuance costs	(18,479)	—	(18,479)	(100)%
Net cash provided by financing activities	$ 13,748	$ 182,343	$ (168,595)	(92)%

Debt

We are the borrower under our Senior Secured Credit Facility and a party to the indentures governing our senior unsecured notes.

Senior Secured Credit Facility

As of December 31, 2020, the Senior Secured Credit Facility had a maximum credit amount of $2.0 billion and a borrowing base and an aggregate elected commitment of $725.0 million each, with $255.0 million outstanding and was subject to an interest rate of 2.688%. The Senior Secured Credit Facility provides for the issuance of letters of credit, limited to the lesser of total capacity or $80.0 million. As of December 31, 2020 and 2019, we had one letter of credit outstanding of $44.1 million and $14.7 million, respectively, under the Senior Secured Credit Facility.

See Notes 7.c and 19.a to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our Senior Secured Credit Facility.

January 2025 Notes and January 2028 Notes

The following table presents principal amounts and applicable interest rates for our outstanding January 2025 Notes and January 2028 Notes as of December 31, 2020:

(in millions, except for interest rates)	Principal	Interest rate
January 2025 Notes	$ 577.9	9.500 %
January 2028 Notes	361.0	10.125 %
Total senior unsecured notes	$ 938.9	

The net proceeds from the January 2025 Notes and January 2028 Notes were used to fund the tender offers and redemptions of the remaining principal amounts of the January 2022 Notes and March 2023 Notes. Under our bond repurchase program, we repurchased a portion of our January 2025 Notes and 2028 Notes during the year ended December 31, 2020. See Notes 7.a and 7.b to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our senior unsecured notes.

Obligations and commitments

The following table presents significant contractual obligations and commitments as of December 31, 2020:

(in thousands)	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
Senior unsecured notes[1]	$ 91,457	$ 182,915	$ 733,377	$ 452,434	$ 1,460,183
Senior Secured Credit Facility[2]	—	255,000	—	—	255,000
Firm sale and transportation commitments[3]	60,993	98,297	69,048	46,114	274,452
Asset retirement obligations[4]	3,550	26,029	5,589	33,158	68,326
Lease commitments[5]	12,831	5,911	2,567	1,988	23,297
Sand commitment[6]	4,699	—	—	—	4,699
Total	$ 173,530	$ 568,152	$ 810,581	$ 533,694	$ 2,085,957

(1) Values presented include both our principal and interest obligations. See Note 7.a to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our January 2025 Notes and January 2028 Notes.

(2) The principal on our Senior Secured Credit Facility is due on April 19, 2023. This table does not include future loan advances, repayments, commitment fees or other fees on our Senior Secured Credit Facility as we cannot determine with accuracy the timing of such items. Additionally, this table does not include interest expense as it is a floating rate instrument and we cannot determine with accuracy the future interest rates to be charged. See Notes 7.c and 19.a to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our Senior Secured Credit Facility and related subsequent events, respectively.

(3) We have committed to deliver, for sale or transportation, fixed volumes of product under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. If not fulfilled, we are subject to firm transportation payments on excess pipeline capacity and other contractual penalties. Of this amount, $84.0 million is related to transportation commitments with a certain pipeline pertaining to the gathering of our production from our established acreage that extends into 2024. We believe we will be able to meet the majority of this commitment, however, as development plans evolve and refine, we may be unable to meet a portion of this commitment. At this time, we are unable to satisfy this particular commitment with produced or purchased oil. As such, we expensed firm transportation payments on excess capacity of $4.0 million during the year ended December 31, 2020. See "Part I. Item 1A. Risk Factors" and Note 16.c to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our firm sale and transportation commitments.

(4) Amounts represent our asset retirement obligation liabilities. See Note 2.k to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our asset retirement obligations.

(5) Amounts represent our minimum lease payments for our operating lease liabilities. We have committed to a drilling rig contract with a third party to facilitate our drilling plans. Included in the value in the table is the gross amount we are committed to pay for the drilling rig contract. However, we will record our proportionate share based on our working interest in our consolidated financial statements as incurred. Management does not currently anticipate the early termination of this contract in 2021. See Notes 5 and 16.b to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our leases and drilling rig contract, respectively.

(6) We have committed to take delivery of processed sand at a fixed price for one year, which is utilized in our completions activities, from our sand mine that is operated by a third-party contractor. Management does not currently anticipate a shortfall under this commitment. See Note 16.d to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our sand commitment.

Non-GAAP financial measures

The non-GAAP financial measures of Free Cash Flow and Adjusted EBITDA, as defined by us, may not be comparable to similarly titled measures used by other companies. Therefore, these non-GAAP financial measures should be considered in conjunction with net income or loss and other performance measures prepared in accordance with GAAP, such as operating

income or loss or cash flows from operating activities. Free Cash Flow and Adjusted EBITDA should not be considered in isolation or as a substitute for GAAP measures, such as net income or loss, operating income or loss or any other GAAP measure of liquidity or financial performance.

Free Cash Flow

Free Cash Flow is a non-GAAP financial measure that we define as net cash provided by operating activities (GAAP) before changes in operating assets and liabilities, net, less costs incurred, excluding non-budgeted acquisition costs. Free Cash Flow does not represent funds available for future discretionary use because it excludes funds required for future debt service, capital expenditures, acquisitions, working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Free Cash Flow is useful to management and investors in evaluating operating trends in our business that are affected by production, commodity prices, operating costs and other related factors. There are significant limitations to the use of Free Cash Flow as a measure of performance, including the lack of comparability due to the different methods of calculating Free Cash Flow reported by different companies.

The following table presents a reconciliation of net cash provided by operating activities (GAAP) to Free Cash Flow (non-GAAP) for the periods presented:

	Years ended December 31	
(in thousands)	**2020**	**2019**
Net cash provided by operating activities	$ 383,390	$ 475,074
Less:		
Change in current assets and liabilities, net	36,699	(64,123)
Change in noncurrent assets and liabilities, net	(16,658)	(2,070)
Cash flows from operating activities before changes in operating assets and liabilities, net	363,349	541,267
Less costs incurred, excluding non-budgeted acquisition costs:		
Oil and natural gas properties[(1)]	344,160	470,455
Midstream service assets[(1)]	2,985	8,655
Other fixed assets	4,148	2,470
Total costs incurred, excluding non-budgeted acquisition costs	351,293	481,580
Free Cash Flow (non-GAAP)	$ 12,056	$ 59,687

(1) Includes capitalized share-settled equity-based compensation and asset retirement costs.

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for share-settled equity-based compensation, depletion, depreciation and amortization, impairment expense, mark-to-market on derivatives, premiums paid for commodity derivatives that matured during the period, accretion expense, gains or losses on disposal of assets, interest expense, income taxes and other non-recurring income and expenses. Adjusted EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Adjusted EBITDA does not represent funds available for future discretionary use because it excludes funds required for debt service, capital expenditures, working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Adjusted EBITDA is useful to an investor in evaluating our operating performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items that can vary substantially from company to company depending upon accounting methods, the book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and

- is used by our management for various purposes, including as a measure of operating performance, in presentations to our board of directors and as a basis for strategic planning and forecasting.

There are significant limitations to the use of Adjusted EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss and the lack of comparability of results of operations to different companies due to the different methods of calculating Adjusted EBITDA reported by different companies. Our measurements of Adjusted EBITDA for financial reporting as compared to compliance under our debt agreements differ.

The following table presents a reconciliation of net loss (GAAP) to Adjusted EBITDA (non-GAAP) for the periods presented:

	Years ended December 31,	
(in thousands, unaudited)	**2020**	**2019**
Net loss	$ (874,173)	$ (342,459)
Plus:		
Share-settled equity-based compensation, net	8,217	8,290
Depletion, depreciation and amortization	217,101	265,746
Impairment expense	899,039	620,889
Organizational restructuring expenses	4,200	16,371
Mark-to-market on derivatives:		
Gain on derivatives, net	(80,114)	(79,151)
Settlements received for matured derivatives, net	228,221	63,221
Settlements received (paid) for early-terminated commodity derivatives, net	6,340	(5,409)
Premiums paid for commodity derivatives that matured during the period[(1)]	(477)	(9,063)
Accretion expense	4,430	4,118
Loss on disposal of assets, net	963	248
Interest expense	105,009	61,547
Gain on extinguishment of debt, net	(8,989)	—
Litigation settlement	—	(42,500)
Write-off of debt issuance costs	1,103	935
Income tax benefit	(3,946)	(2,588)
Adjusted EBITDA (non-GAAP)	$ 506,924	$ 560,195

(1) Reflects premiums incurred previously or upon settlement that are attributable to derivatives settled in the respective periods presented and were not a result of a hedge restructuring.

Critical accounting estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting estimates are considered to be critical if (i) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (ii) the impact of the estimates and assumptions on financial condition or operating performance is material. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements.

In management's opinion, the most critical accounting estimates impacted by our judgments and estimates are (i) volumes of our reserves of oil, NGL and natural gas, (ii) future cash flows from oil and natural gas properties, (iii) deferred income taxes, (iv) asset retirement obligations and (v) fair values of assets acquired and liabilities assumed in a business combination.

There have been no material changes in our accounting estimates during the year ended December 31, 2020. See Note 2 to our consolidated financial statements included elsewhere in this Annual Report for discussion on significant accounting policies and estimates made by management. See "Item 9A. Controls and Procedures" for discussion of the material weakness regarding our March 31, 2020 reserves estimate and the remediation of the controls surrounding our reserves estimation process.

Oil, NGL and natural gas reserve quantities and standardized measure of discounted future net cash flows

On an annual basis, our independent reserve engineers prepare the estimates of oil, NGL and natural gas reserves and associated future net cash flows. The SEC has defined proved reserves as the estimated quantities of oil, NGL and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The process of estimating oil, NGL and natural gas reserves is complex, requiring significant judgment in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective assumptions and variances in available data for various properties increase the likelihood of significant changes in these estimates. If such changes are material, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material. See Notes 20.d and 20.e to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our net proved oil, NGL and natural gas reserves and standardized measure of discounted future net cash flows, respectively.

Asset retirement obligations ("ARO")

We have significant obligations to (i) plug, abandon and remediate the properties at the end of their productive lives and (ii) to remove certain midstream service assets and remediate the sites where such midstream service assets are located upon the retirement of those assets. Estimating the future asset removal costs is difficult and requires us to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Significant inputs to the valuation include: (i) estimated plug and abandonment cost per well based on our experience and estimated remaining life per well, (ii) estimated removal and/or remediation costs for midstream service assets and estimated remaining life of midstream service assets, (iii) future inflation factors and (iv) our average credit-adjusted risk-free rate. Inherent in the fair value calculation of ARO are numerous assumptions and judgments including, in addition to those noted above, the ultimate settlement of these amounts, the ultimate timing of such settlement and changes in technology, regulatory, political, environmental, safety and public relations matters. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, an adjustment will be made to the asset balance. See Note 2.k to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our ARO.

Income taxes

As of December 31, 2020 and 2019, we had a net deferred tax asset of $1.5 million and a net deferred tax liability of $2.5 million, respectively.

As part of the process of preparing the consolidated financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which we operate. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items such as derivative instruments, depletion, depreciation and amortization, and certain accrued assets and liabilities for tax and financial accounting purposes. These differences and our net operating loss carry-forwards result in deferred tax assets and liabilities, which are included in our consolidated balance sheets. We must then assess, using all available negative and positive evidence, the likelihood that the deferred tax assets will be recovered from future taxable income.

If we believe that recovery is not likely, we must establish a valuation allowance. Generally, to the extent we establish a valuation allowance or increase or decrease this allowance in a period, we must include an expense or reduction of expense within the tax provision in the consolidated statement of operations.

Under accounting guidance for income taxes, an enterprise must use judgment in considering the relative impact of negative and positive evidence. The weight given to the potential effect of negative and positive evidence should be commensurate with the extent to which it can be objectively verified. The more negative evidence that exists (i) the more positive evidence is necessary and (ii) the more difficult it is to support a conclusion that a valuation allowance is not needed for all or a portion of the deferred tax asset. Among the more significant types of evidence that we consider are:

- our earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition;
- the ability to recover our net operating loss carry-forward deferred tax assets in future years;
- the existence of significant proved oil, NGL and natural gas reserves;
- our ability to use tax planning strategies, such as electing to capitalize intangible drilling costs as opposed to expensing such costs;
- current price protection utilizing oil and natural gas hedges;
- future revenue and operating cost projections that indicate we will produce more than enough taxable income to realize the deferred tax asset based on existing sales prices and cost structures; and
- current market prices for oil, NGL and natural gas.

During 2020, in evaluating whether it was more-likely-than-not that our deferred tax asset was recoverable from future net income, we considered all positive and negative evidence available and determined it was more likely than not that the net deferred tax assets were not realizable and a valuation was necessary. We will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods. See Note 13 to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our income taxes.

Business combinations

As part of our business strategy, we periodically pursue the acquisition of oil and natural gas properties that is accounted for as a business combination. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. We make various assumptions in estimating the fair values of assets acquired and liabilities assumed. The most significant assumptions relate to the estimated fair values of evaluated and unevaluated oil and natural gas properties, which are measured using a discounted cash flow model that converts future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) forecasted oil, NGL and natural gas reserve quantities; (ii) future commodity strip prices as of the closing dates adjusted for transportation and regional price differentials; (iii) forecasted ad valorem taxes, production taxes, income taxes, operating expenses and development costs; and (iv) a peer group weighted-average cost of capital rate subject to additional project-specific risk factors. To compensate for the inherent risk of estimating the value of the unevaluated properties, the discounted future net cash flows of proved undeveloped and probable reserves are reduced by additional reserve adjustment factors. Changes in key assumptions may cause the business combination accounting to be revised, including the recognition of additional goodwill or discount on acquisition. See Note 4.c to our consolidated financial statements included elsewhere in this Annual Report for additional discussion of our 2019 business combination.

New accounting standards

See Note 3 to our consolidated financial statements included elsewhere in this Annual Report for discussion of new accounting standards.

Inflation

Inflation in the U.S. has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2020, 2019 and 2018. Although the impact of inflation has been insignificant in recent years, it

continues to be a factor in the U.S. economy and, historically, we have experienced inflationary pressure on the costs of oilfield services and equipment as drilling activity increases in the areas in which we operate.

Off-balance sheet arrangements

Currently, we do not have any off-balance sheet arrangements other than our firm sale and transportation commitments, which are described in "—Obligations and commitments" and certain operating leases with a term less than or equal to 12 months. See Notes 5 and 16 to our consolidated financial statements included elsewhere in this Annual Report for additional information on our leases and commitments and contingencies, respectively.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk," in our case, refers to the risk of loss arising from adverse changes in oil, NGL and natural gas prices and in interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of how we view and manage our ongoing market risk exposures. All of our market risk-sensitive derivative instruments were entered into for hedging purposes, rather than for speculative trading.

Oil, NGL and natural gas price exposure

Due to the inherent volatility in oil, NGL and natural gas prices and differences in the prices of oil, NGL and natural gas between where we produce and where we sell such commodities, we engage in commodity derivative transactions, such as puts, swaps, collars and basis swaps to hedge price risk associated with a portion of our anticipated sales volumes. By removing a portion of the price volatility associated with future sales volumes, we expect to mitigate, but not eliminate, the potential effects of variability in cash flows from operations.

The fair values of our open commodity and contingent consideration derivative positions are largely determined by the relevant forward commodity price curves of the indexes associated with our open derivative positions. We had a $34.9 million net liability position from the fair values of our open commodity derivatives and a $0.8 million liability position from the fair value of our potential contingent consideration payment associated with an acquisition, each as of December 31, 2020. The following table provides a sensitivity analysis of the projected incremental effect on income (loss) before income taxes of a hypothetical 10% change in the relevant forward commodity price curves of the indexes associated with our open commodity and contingent consideration derivative positions as of December 31, 2020:

(in thousands)	10% Increase	10% Decrease
Commodity	$ (76,868)	$ 78,976
Contingent consideration	(130)	175
Total	$ (76,998)	$ 79,151

See Notes 2.e, 10.a, 10.c, 11.a and 19.b to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our commodity and contingent consideration derivatives.

Interest rate risk

Our Senior Secured Credit Facility bears interest at a floating rate and our notes bear interest at fixed rates. The maturity years, outstanding balances and interest rates on our long-term debt as of December 31, 2020 were as follows:

	Maturity year		
(in millions except for interest rates)	2023	2025	Thereafter
January 2025 Notes	$ —	$ 577.9	$ —
Fixed interest rate	— %	9.500 %	— %
January 2028 Notes	$ —	$ —	$ 361.0
Fixed interest rate	— %	— %	10.125 %
Senior Secured Credit Facility	$ 255.0	$ —	$ —
Floating interest rate	2.688 %	— %	— %

Due to the inherent volatility in interest rates, we have entered into an interest rate derivative swap to hedge interest rate risk associated with a portion of our anticipated outstanding debt under the Senior Secured Credit Facility. We will pay a fixed rate over the contract term for that portion. By removing a portion of the interest rate volatility associated with anticipated outstanding debt, we expect to mitigate, but not eliminate, the potential effects of variability in cash flows from operations.

The fair value of our open interest rate derivative position is largely determined by the LIBOR interest rate forward curve associated with our open position. We had a $0.3 million total liability position from the net fair value of our open interest rate derivative as of December 31, 2020. The following table provides a sensitivity analysis of the projected incremental effect on income (loss) before income taxes of a hypothetical 1% incremental addition to or subtraction from the relevant LIBOR forward curve interest rates associated with our open interest rate derivative position as of December 31, 2020:

(in thousands)	1% incremental addition to	1% incremental subtraction from
Interest rate	$ 1,316	$ (1,316)

See Notes 7, 11.c and 19.a to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our debt. See Notes 10.b and 11.a to our consolidated financial statements included elsewhere in this Annual Report for further discussion of our interest rate derivative.

Counterparty and customer credit risk

See Notes 15 and 16 to our consolidated financial statements included elsewhere in this Annual Report for discussion of credit risk and commitments and contingencies. See Notes 2.d and 14 to our consolidated financial statements included elsewhere in this Annual Report for discussion of our accounts receivable and revenue recognition, respectively. See Notes 2.e, 10.a, 11.a and 19.b to our consolidated financial statements included elsewhere in this Annual Report for discussion of our commodity derivatives.

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements and supplementary financial data are included in this Annual Report beginning on page F-1.

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2020, management assessed the effectiveness of the Company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in the 2013 "Internal Control - Integrated Framework," issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2020.

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.

Grant Thornton LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report, has issued their report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2020. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2020, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Laredo Petroleum, Inc.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Laredo Petroleum, Inc. (a Delaware corporation) and subsidiaries (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 February 22, 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

Tulsa, Oklahoma
February 22, 2021

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

We had no changes in, and no disagreements with, our accountants on accounting and financial disclosure.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that the material weakness mentioned below was remediated during the fourth quarter and that our disclosure controls and procedures were effective as of December 31, 2020.

Material Weakness in Internal Control over Financial Reporting

A material weakness (as defined in Rule 12b-2 under the Exchange Act) is a deficiency, or a combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

As noted in the second-quarter 2020 Quarterly Report, we identified deficiencies that represented a material weakness in our internal control over financial reporting as of March 31, 2020 with respect to the design and maintenance of controls over the determination of the estimated present value ("PV-10") of our reserves. Specifically, we did not design and maintain effective controls to sufficiently review the completeness and accuracy of the future production costs component of the estimated PV-10 of our reserves and, thus, failed to identify the omission of the transportation costs from the future costs required to develop certain of our reserves. These deficiencies had the effect of causing an overstatement of approximately $160 million in the estimated PV-10 of our reserves as of March 31, 2020, which caused an understatement in our full cost ceiling impairment expense and related adjustments for the quarter. An amendment was filed to our quarterly report on Form 10-Q for the quarter ended March 31, 2020 to correct the error and restate the financial statements for the first quarter of 2020 included in such report.

Remediation Plan

As part of our commitment to strengthening our internal control over financial reporting, we implemented a remediation plan under the oversight of the Audit Committee of our board of directors to address these deficiencies, which included the following actions:

- implementation of additional (or enhanced) procedures to verify the completeness and accuracy of data inputs into the reserves application for pricing and operating expenses;
- implementation of additional (or enhanced) procedures to perform enhanced detailed reviews of reserves report components, including (but not necessarily limited to) pricing and operating expenses; and
- revision and communication of the accounting controls, policies and procedures relating to identifying and assessing changes that could potentially impact the system of internal control governing the full cost ceiling test calculation.

Design and Evaluation of Internal Control Over Financial Reporting

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, our management has included a report of their assessment of the design and operating effectiveness of our internal controls over financial reporting as part of this Annual Report for the year ended December 31, 2020. Grant Thornton LLP, the Company's independent registered public accounting firm, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting. Management's report and the independent registered public accounting firm's attestation report are included in "Item 8. Financial Statements and Supplementary Data" in this Annual Report under the caption entitled "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm," respectively, and are incorporated herein by reference.

Changes in Internal Control over Financial Reporting

Except for changes we made in connection with the implementation of the remediation plan described above, there have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

Item 9B. Other Information

Not applicable.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Information regarding our Code of Conduct and Business Ethics, Code of Ethics For Senior Financial Officers and Corporate Governance Guidelines for our principal executive officer, principal financial officer and principal accounting officer are described in "Item 1. Business" in this Annual Report. Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 10 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2020.

Item 11. Executive Compensation

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 11 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2020.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 12 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2020.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 13 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2020.

Item 14. Principal Accounting Fees and Services

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 14 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2020.

(a)(2) Financial Statement Schedules

All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

Part IV

Item 15. Exhibits, Financial Statement Schedules

(a)(1) Financial Statements

Our consolidated financial statements are included under Part II, Item 8 Financial Statements and Supplementary Data" in this Annual Report. For a listing of these statements and accompanying footnotes, see "Index to Consolidated Financial Statements" on page F-1 of this Annual Report.

(a)(3) Exhibits

Exhibit	Description	Incorporated by reference (File No. 001-35380, unless otherwise indicated)		
		Form	Exhibit	Filling Date
2.1	Agreement and Plan of Merger by and between Laredo Petroleum, LLC and Laredo Petroleum Holdings, Inc., dated as of December 19, 2011.	8-K	2.1	12/22/2011
3.1	Amended and Restated Certificate of Incorporation of Laredo Petroleum Holdings, Inc., dated as of December 19, 2011.	8-K	3.1	12/22/2011
3.2	Certificate of Amendment to the Amended and Restated Certificate of Incorporation of Laredo Petroleum Holdings, Inc., dated as of June 1, 2020.	8-K	3.1	6/1/2020
3.3	Certificate of Ownership and Merger, dated as of December 30, 2013.	8-K	3.1	1/6/2014
3.4	Second Amended and Restated Bylaws of Laredo Petroleum, Inc., adopted February 10, 2016.	10-K	3.3	2/17/2016
4.1	Form of Common Stock Certificate.	8-A12B/A	4.1	1/7/2014
4.2*	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934.			
4.3	Indenture, dated as of March 18, 2015, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Bank, N.A., as trustee.	8-K	4.1	3/24/2015
4.4	Third Supplemental Indenture, dated as of January 24, 2020, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Bank, N.A., as trustee.	8-K	4.4	1/24/2020
4.5	Fourth Supplemental Indenture, dated as of January 24, 2020, among Laredo Petroleum, Inc., Laredo Midstream Services, LLC, Garden City Minerals, LLC and Wells Fargo Bank, N.A., as trustee.	8-K	4.6	1/24/2020
10.1	Fifth Amended and Restated Credit Agreement, dated as of May 2, 2017, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, and the other financial institutions signatory thereto.	10-Q	10.1	5/4/2017
10.2	First Amendment to Fifth Amended and Restated Credit Agreement, dated as of October 24, 2017, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto.	8-K	10.1	10/30/2017
10.3	Second Amendment to Fifth Amended and Restated Credit Agreement, dated as of February 14, 2018, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto.	10-K	10.3	2/15/2018
10.4	Third Amendment to Fifth Amended and Restated Credit Agreement, dated as of April 19, 2018, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto.	8-K	10.1	4/23/2018
10.5	Fourth Amendment to Fifth Amended and Restated Credit Agreement, dated as of April 30, 2020, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto.	8-K	10.1	5/6/2020
10.6	Fifth Amendment to the Fifth Amended and Restated Credit Agreement, dated as of October 22, 2020, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto.	8-K	10.1	10/22/2020
10.7	Schedule 1, amended and restated as of January 22, 2020, to the Third Amendment to the Fifth Amended and Restated Credit Agreement, dated as of April 19, 2018, among Laredo Petroleum, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, Laredo Midstream Services, LLC and Garden City Minerals, LLC, as guarantors and the banks signatory thereto.	10-K	10.5	2/13/2020
10.8	Amended and Restated Form of Indemnification Agreement between Laredo Petroleum Holdings, Inc. and each of the officers and directors thereof.	10-Q	10.5	5/2/2019
10.9#	Laredo Petroleum, Inc. Omnibus Equity Incentive Plan, as amended and restated as of May 16, 2019.	8-K	10.1	5/16/2019
10.10#	Amendment to the Laredo Petroleum, Inc. Omnibus Equity Incentive Plan, as amended and restated as of May 16, 2019.	8-K	10.1	6/1/2020
10.11#	Laredo Petroleum, Inc. Change in Control Executive Severance Plan, as amended June 21, 2015, December 14, 2015 and September 9, 2016.	10-K	10.18	2/16/2017

10.12#	Laredo Petroleum, Inc. Executive Severance Plan, effective as of February 20, 2020.	8-K	10.1	2/26/2020
10.13#	Offer Letter, dated April 17, 2019, between Laredo Petroleum, Inc. and Mr. Jason Pigott.	10-Q	10.3	5/2/2019
10.14#	Offer Letter, dated June 12, 2020, between Laredo Petroleum, Inc. and Mr. Bryan J. Lemmerman.	10-Q	10.3	8/6/2020
10.15#	Form of Stock Option Agreement.	8-K	10.3	5/25/2016
10.16#	Form of 2018 Performance Share Unit Award Agreement.	8-K	10.1	2/23/2018
10.17#	Form of 2019 Performance Share Unit Award Agreement.	10-Q	10.4	5/2/2019
10.18#*	Form of 2020 Performance Share Unit Award Agreement.			
10.19#	Form of Outperformance Share Unit Award Agreement.	10-Q	10.8	8/1/2019
10.20#	Form of Restricted Stock Unit Agreement.	8-K	10.2	5/25/2016
10.21#*	Form of Phantom Unit Agreement.			
21.1*	List of Subsidiaries of Laredo Petroleum, Inc.			
23.1*	Consent of Grant Thornton LLP.			
23.2*	Consent of Ryder Scott Company, L.P.			
31.1*	Certification of Chief Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.			
31.2*	Certification of Chief Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.			
32.1**	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18. U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.			
95.1*	Mine Safety Disclosures.			
99.1*	Summary Report of Ryder Scott Company, L.P.			
101	The following financial information from Laredo's Annual Report on Form 10-K for the year ended December 31, 2020, formatted in Inline XBRL: (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Stockholders' Equity, (iv) Consolidated Statements of Cash Flows and (v) Notes to the Consolidated Financial Statements.			
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).			

* Filed herewith.

** Furnished herewith.

Management contract or compensatory plan or arrangement.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

	Laredo Petroleum, Inc.	
Date: February 22, 2021	By:	/s/ Jason Pigott
		Jason Pigott *President and Chief Executive Officer*

KNOWN ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Jason Pigott, Bryan J. Lemmerman, T. Karen Chandler, Mark D. Denny and Jessica R. Wren, each of whom may act without joinder of the other, as their true and lawful attorneys-in-fact and agents, each with full power of substitution and resubstitution, for such person and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signatures	Title	Date
/s/ Jason Pigott Jason Pigott	President and Chief Executive Officer (principal executive officer)	2/22/2021
/s/ Bryan J. Lemmerman Bryan J. Lemmerman	Senior Vice President and Chief Financial Officer (principal financial officer)	2/22/2021
/s/ Jessica R. Wren Jessica R. Wren	Interim Principal Accounting Officer (principal accounting officer)	2/22/2021
/s/ William E. Albrecht William E. Albrecht	Chairman	2/22/2021
/s/ Francis Powell Hawes Frances Powell Hawes	Director	2/22/2021
/s/ Jarvis V. Hollingsworth Jarvis V. Hollingsworth	Director	2/22/2021
/s/ Craig M. Jarchow Craig M. Jarchow	Director	2/22/2021
/s/ Lisa M. Lambert Lisa M. Lambert	Director	2/22/2021
/s/ Lori A. Lancaster Lori A. Lancaster	Director	2/22/2021
/s/ James R. Levy James R. Levy	Director	2/22/2021
/s/ Pamela S. Pierce Pamela S. Pierce	Director	2/22/2021
/s/ Dr. Myles W. Scoggins Dr. Myles W. Scoggins	Director	2/22/2021
/s/ Edmund P. Segner, III Edmund P. Segner, III	Director	2/22/2021

Index to Consolidated Financial Statements

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Laredo Petroleum, Inc.

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Laredo Petroleum, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2020 and 2019, the related consolidated statements of operations, stockholders' 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 February 22, 2021 expressed an unqualified opinion.

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 matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that were 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 matters below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

- <u>Depletion expense and impairment of oil and gas properties impacted by the Company's estimation of proved reserves</u>

    As described further in Notes 2 and 6 to the financial statements, the Company accounts for its oil and natural gas properties using the full cost method of accounting which requires management to make estimates of proved reserve volumes and future net revenues to record depletion expense and to determine if any impairment exists for its oil and natural gas properties. To estimate the volume of proved reserves and future net revenues, 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 proved reserves to determine if wells are expected, with reasonable certainty, to be economical under the appropriate pricing assumptions required in the estimation of depletion expense and impairment expense. We identified the estimation of proved

reserves of oil and natural gas properties due to its impact on depletion expense and impairment of oil and natural gas properties as a critical audit matter.

The principal consideration for our determination that the estimation of proved reserves is a critical audit matter is that changes in certain inputs and assumptions, which require a high degree of subjectivity, necessary to estimate the volume and future revenues of the Company's proved reserves could have a significant impact on the measurement of depletion expense 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 effectiveness of controls relating to management's estimation of proved reserves for the purpose of estimating depletion expense and assessing the Company's oil and natural gas properties for potential impairment. Specifically, these controls related to the use of historical information in the estimation of proved reserves derived from the Company's accounting records and the management review controls performed on information provided to the reservoir engineering specialists and the management review controls on the final proved reserves report prepared by the Company's reservoir engineering specialists.
- We evaluated the level of knowledge, skill, and ability of the Company's reservoir engineering specialists and their relationship to the Company, made inquiries of those reservoir engineers regarding the process followed and judgments made to estimate the Company's proved reserve volumes, and read the reserve report prepared by the Company's reservoir engineering specialists.
- We evaluated sensitive inputs and assumptions used to determine proved reserve volumes and other financial inputs and assumptions, including certain assumptions that are derived from the Company's accounting records. These assumptions included historical pricing differentials, future operating costs, estimated future capital costs, and ownership interests. We tested management's process for determining the assumptions, including examining the underlying support, on a sample basis. 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 the pricing differentials;
    - Evaluated the models used to estimate the future operating costs at year-end and compared the models to historical operating costs;
    - Evaluated the models used to estimate future capital expenditures to amounts expended for recently drilled and completed wells;
    - Evaluated the ownership interests used in the reserve report by inspecting lease and title records;
    - Evaluated the Company's evidence supporting the amount of 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 the reserve report to historical actual results and to the prior year reserve report.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2007.

Tulsa, Oklahoma
February 22, 2021

Consolidated balance sheets

(in thousands, except share data)	December 31, 2020	December 31, 2019
Assets		
Current assets:		
Cash and cash equivalents	$ 48,757	$ 40,857
Accounts receivable, net	63,976	85,223
Derivatives	7,893	51,929
Other current assets	15,964	22,470
Total current assets	136,590	200,479
Property and equipment:		
Oil and natural gas properties, full cost method:		
Evaluated properties	7,874,932	7,421,799
Unevaluated properties not being depleted	70,020	142,354
Less accumulated depletion and impairment	(6,817,949)	(5,725,114)
Oil and natural gas properties, net	1,127,003	1,839,039
Midstream service assets, net	112,697	128,678
Other fixed assets, net	32,011	32,504
Property and equipment, net	1,271,711	2,000,221
Derivatives	—	23,387
Operating lease right-of-use assets	17,973	28,343
Other noncurrent assets, net	16,336	12,007
Total assets	$ 1,442,610	$ 2,264,437
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 38,279	$ 40,521
Accrued capital expenditures	28,275	36,328
Undistributed revenue and royalties	24,728	33,123
Derivatives	31,826	7,698
Operating lease liabilities	11,721	14,042
Other current liabilities	62,766	39,184
Total current liabilities	197,595	170,896
Long-term debt, net	1,179,266	1,170,417
Derivatives	12,051	—
Asset retirement obligations	64,775	60,691
Operating lease liabilities	8,918	17,208
Other noncurrent liabilities	1,448	3,351
Total liabilities	1,464,053	1,422,563
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $0.01 par value, 50,000,000 shares authorized and zero issued as of December 31, 2020 and 2019	—	—
Common stock, $0.01 par value, 22,500,000 shares authorized and 12,020,164 and 11,864,604 issued and outstanding as of December 31, 2020 and 2019, respectively[(1)]	120	2,373
Additional paid-in capital	2,398,464	2,385,355
Accumulated deficit	(2,420,027)	(1,545,854)
Total stockholders' equity	(21,443)	841,874
Total liabilities and stockholders' equity	$ 1,442,610	$ 2,264,437

(1) Common stock shares were retroactively adjusted for the Company's 1-for-20 reverse stock split effective June 1, 2020. See Note 8.a.

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

Consolidated statements of operations

(in thousands, except per share data)	Years ended December 31, 2020	2019	2018
Revenues:			
Oil sales	$ 367,792	$ 572,918	$ 605,197
NGL sales	78,246	100,330	149,843
Natural gas sales	50,317	33,300	53,490
Midstream service revenues	8,249	11,928	8,987
Sales of purchased oil	172,588	118,805	288,258
Total revenues	677,192	837,281	1,105,775
Costs and expenses:			
Lease operating expenses	82,020	90,786	91,289
Production and ad valorem taxes	33,050	40,712	49,457
Transportation and marketing expenses	49,927	25,397	11,704
Midstream service expenses	3,762	4,486	2,872
Costs of purchased oil	194,862	122,638	288,674
General and administrative	50,534	54,729	96,138
Organizational restructuring expenses	4,200	16,371	—
Depletion, depreciation and amortization	217,101	265,746	212,677
Impairment expense	899,039	620,889	—
Other operating expenses	4,430	4,118	4,472
Total costs and expenses	1,538,925	1,245,872	757,283
Operating income (loss)	(861,733)	(408,591)	348,492
Non-operating income (expense):			
Gain on derivatives, net	80,114	79,151	42,984
Interest expense	(105,009)	(61,547)	(57,904)
Litigation settlement	—	42,500	—
Gain on extinguishment of debt, net	8,989	—	—
Loss on disposal of assets, net	(963)	(248)	(5,798)
Write-off of debt issuance costs	(1,103)	(935)	—
Other income, net	1,586	4,623	1,070
Total non-operating income (expense), net	(16,386)	63,544	(19,648)
Income (loss) before income taxes	(878,119)	(345,047)	328,844
Income tax benefit (expense):			
Current	—	—	807
Deferred	3,946	2,588	(5,056)
Total income tax benefit (expense)	3,946	2,588	(4,249)
Net income (loss)	$ (874,173)	$ (342,459)	$ 324,595
Net income (loss) per common share[1]:			
Basic	$ (74.92)	$ (29.61)	$ 27.94
Diluted	$ (74.92)	$ (29.61)	$ 27.84
Weighted-average common shares outstanding[1]:			
Basic	11,668	11,565	11,617
Diluted	11,668	11,565	11,659

(1) Net income (loss) per common share and weighted-average common shares outstanding were retroactively adjusted for the Company's 1-for-20 reverse stock split effective June 1, 2020 as discussed in Note 8.a.

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

Consolidated statements of stockholders' equity

(in thousands)	Common stock Shares[(1)]	Common stock Amount	Additional paid-in capital	Treasury stock (at cost) Shares[(1)]	Treasury stock (at cost) Amount	Accumulated deficit	Total
Balance, December 31, 2017	12,126	$ 2,425	$ 2,432,262	—	$ —	$ (1,669,108)	$ 765,579
Adjustment to the beginning balance of accumulated deficit upon adoption of ASC 606	—	—	—	—	—	141,118	141,118
Restricted stock awards	166	33	(33)	—	—	—	—
Restricted stock forfeitures	(18)	(4)	4	—	—	—	—
Share repurchases	—	—	—	552	(97,055)	—	(97,055)
Stock exchanged for tax withholding	—	—	—	26	(4,418)	—	(4,418)
Retirement of treasury stock	(578)	(115)	(101,358)	(578)	101,473	—	—
Exercise of stock options	1	—	86	—	—	—	86
Share-settled equity-based compensation	—	—	44,325	—	—	—	44,325
Net income	—	—	—	—	—	324,595	324,595
Balance, December 31, 2018	11,697	2,339	2,375,286	—	—	(1,203,395)	1,174,230
Restricted stock awards	381	76	(76)	—	—	—	—
Restricted stock forfeitures	(178)	(35)	35	—	—	—	—
Stock exchanged for tax withholding	—	—	—	35	(2,657)	—	(2,657)
Stock exchanged for cost of exercise of stock options	—	—	—	1	(76)	—	(76)
Retirement of treasury stock	(36)	(7)	(2,726)	(36)	2,733	—	—
Exercise of stock options	1	—	76	—	—	—	76
Share-settled equity-based compensation	—	—	12,760	—	—	—	12,760
Net loss	—	—	—	—	—	(342,459)	(342,459)
Balance, December 31, 2019	11,865	2,373	2,385,355	—	—	(1,545,854)	841,874
Reverse stock split[(2)]	—	(2,277)	2,277	—	—	—	—
Restricted stock awards	238	31	(31)	—	—	—	—
Restricted stock forfeitures	(48)	(2)	2	—	—	—	—
Stock exchanged for tax withholding	—	—	—	35	(779)	—	(779)
Retirement of treasury stock	(35)	(5)	(774)	(35)	779	—	—
Share-settled equity-based compensation	—	—	11,635	—	—	—	11,635
Net loss	—	—	—	—	—	(874,173)	(874,173)
Balance, December 31, 2020	12,020	$ 120	$ 2,398,464	—	$ —	$ (2,420,027)	$ (21,443)

(1) Shares presented were retroactively adjusted for the Company's 1-for-20 reverse stock split effective June 1, 2020 as discussed in Note 8.a.

(2) The amounts presented for common stock and additional paid-in capital are the aggregate retroactive adjustments for the reverse stock split for the life-to-date activity through May 31, 2020.

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

Consolidated statements of cash flows

(in thousands)	Years ended December 31, 2020	2019	2018
Cash flows from operating activities:			
Net income (loss)	$ (874,173)	$ (342,459)	$ 324,595
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Share-settled equity-based compensation, net	8,217	8,290	36,396
Depletion, depreciation and amortization	217,101	265,746	212,677
Impairment expense	899,039	620,889	—
Mark-to-market on derivatives:			
Gain on derivatives, net	(80,114)	(79,151)	(42,984)
Settlements received for matured derivatives, net	228,221	63,221	6,090
Settlements received (paid) for early-terminated commodity derivatives, net	6,340	(5,409)	—
Premiums paid for commodity derivatives	(51,070)	(9,063)	(20,335)
Amortization of debt issuance costs	4,321	3,341	3,331
Amortization of operating lease right-of-use assets	13,070	14,563	—
Gain on extinguishment of debt, net	(8,989)	—	—
Deferred income tax (benefit) expense	(3,946)	(2,588)	5,056
Other, net	5,332	3,887	12,551
Changes in operating assets and liabilities:			
Decrease in accounts receivable, net	21,117	8,924	4,669
Decrease (increase) in other current assets	6,275	(14,059)	(1,865)
(Increase) decrease in other noncurrent assets, net	(6,768)	2,327	124
(Decrease) increase in accounts payable and accrued liabilities	(2,242)	(28,983)	11,163
(Decrease) increase in undistributed revenue and royalties	(8,395)	(16,037)	10,989
Increase (decrease) in other current liabilities	19,944	(13,968)	(23,799)
Decrease in other noncurrent liabilities	(9,890)	(4,397)	(854)
Net cash provided by operating activities	383,390	475,074	537,804
Cash flows from investing activities:			
Acquisitions of oil and natural gas properties	(35,786)	(199,284)	(17,538)
Capital expenditures:			
Oil and natural gas properties	(347,359)	(458,985)	(673,584)
Midstream service assets	(3,171)	(7,910)	(6,784)
Other fixed assets	(4,259)	(2,433)	(7,308)
Proceeds from dispositions of capital assets, net of selling costs	1,337	6,901	12,603
Other, net	—	—	1,655
Net cash used in investing activities	(389,238)	(661,711)	(690,956)
Cash flows from financing activities:			
Borrowings on Senior Secured Credit Facility	80,000	275,000	210,000
Payments on Senior Secured Credit Facility	(200,000)	(90,000)	(20,000)
Issuance of January 2025 Notes and January 2028 Notes	1,000,000	—	—
Extinguishment of debt	(846,994)	—	—
Share repurchases	—	—	(97,055)
Stock exchanged for tax withholding	(779)	(2,657)	(4,418)
Proceeds from exercise of stock options	—	—	86
Payments for debt issuance costs	(18,479)	—	(2,469)
Net cash provided by financing activities	13,748	182,343	86,144
Net increase (decrease) in cash and cash equivalents	7,900	(4,294)	(67,008)
Cash and cash equivalents, beginning of period	40,857	45,151	112,159
Cash and cash equivalents, end of period	$ 48,757	$ 40,857	$ 45,151

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

Notes to the consolidated financial statements

Note 1 Organization

Laredo Petroleum, Inc. ("Laredo"), together with its wholly-owned subsidiaries, Laredo Midstream Services, LLC ("LMS") and Garden City Minerals, LLC ("GCM"), is an independent energy company focused on the acquisition, exploration and development of oil and natural gas properties, primarily in the Permian Basin of West Texas. The Company has identified one operating segment: exploration and production. In these notes, the "Company" refers to Laredo, LMS and GCM collectively, unless the context indicates otherwise. All amounts, dollars and percentages presented in these consolidated financial statements and the related notes are rounded and, therefore, approximate.

Note 2 Basis of presentation and significant accounting policies

a. Basis of presentation

The accompanying consolidated financial statements were derived from the historical accounting records of the Company and reflect the historical financial position, results of operations and cash flows for the periods described herein. The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). All material intercompany transactions and account balances have been eliminated in the consolidation of accounts.

b. Use of estimates in the preparation of consolidated financial statements

The preparation of the accompanying consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions about future events. These estimates and the underlying assumptions affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Although management believes these estimates are reasonable, actual results could differ.

Significant estimates include, but are not limited to, (i) volumes of the Company's reserves of oil, natural gas liquids ("NGL") and natural gas, (ii) future cash flows from oil and natural gas properties, (iii) depletion, depreciation and amortization, (iv) impairments, (v) asset retirement obligations, (vi) equity-based compensation, (vii) deferred income taxes, (viii) fair values of assets acquired and liabilities assumed in a business combination, (ix) fair values of derivatives and deferred premiums and (x) contingent liabilities. As fair value is a market-based measurement, it is determined based on the assumptions that would be used by market participants. These estimates and assumptions are based on management's best judgment. Management evaluates its estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment. Such estimates and assumptions are adjusted when facts and circumstances dictate. Illiquid credit markets and volatile equity and energy markets have combined to increase the uncertainty inherent in such estimates and assumptions. Management believes its estimates and assumptions to be reasonable under the circumstances. As future events and their effects cannot be determined with precision, actual values and results could differ from these estimates. Any changes in estimates resulting from future changes in the economic environment will be reflected in the financial statements in future periods.

c. Cash and cash equivalents

The Company defines cash and cash equivalents to include cash on hand, cash in bank accounts and highly liquid investments with original maturities of three months or less. The Company maintains cash and cash equivalents in bank deposit accounts and money market funds that may not be federally insured. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk on such accounts. See Note 15 for discussion regarding the Company's exposure to credit risk.

d. Accounts receivable

The Company sells its produced oil, NGL and natural gas and purchased oil to various customers and participates with other parties in the development and operation of oil and natural gas properties.

The Company maintains an allowance for expected credit losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers significant factors such as historical losses, current receivables aging, the debtor's current ability to pay its obligation to the Company and existing industry and economic data. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is remote, and payments subsequently received on such balances are credited to the allowance. The adoption of ASU 2016-13 did not result in a material change to the consolidated financial statements. See Note 15 for discussion regarding the Company's exposure to credit risk.

Accounts receivable consisted of the following components as of the dates presented:

(in thousands)	December 31, 2020	December 31, 2019
Oil, NGL and natural gas sales[(1)]	$ 46,714	$ 54,668
Sales of purchased oil and other products	5,083	2,883
Joint operations, net[(2)]	2,753	21,567
Other	9,426	6,105
Total accounts receivable, net	$ 63,976	$ 85,223

(1) Includes the net positions of purchasers that we have netting arrangements with.

(2) Accounts receivable for joint operations are presented net of an allowance for expected credit losses of $0.4 million and allowance for doubtful accounts of $0.3 million as of December 31, 2020 and 2019, respectively. As the operator of the majority of its wells, the Company has the ability to realize some or all of these receivables through the netting of revenues.

e. Derivatives

Derivatives are recorded at fair value and are presented on a net basis in "Derivatives" on the consolidated balance sheets as assets and/or liabilities. The Company presents the fair value of derivatives net by counterparty where the right of offset exists. The Company determines the fair value of its derivatives using fair value hierarchy level inputs to its valuation techniques. The Company's derivatives were not designated as hedges for accounting purposes, and the Company does not enter into such instruments for speculative trading purposes. Accordingly, the changes in fair value are recognized in "Gain on derivatives, net" under "Non-operating income (expense)" on the consolidated statements of operations. Cash settlements received or paid for matured, early-terminated and modified derivatives and premiums paid for commodity derivatives are included in "Settlements received for matured derivatives, net," "Settlements received (paid) for early-terminated commodity derivatives, net" and "Premiums paid for commodity derivatives" each under "Cash flows from operating activities" on the consolidated statements of cash flows. If applicable in the future, settlement paid for the contingent consideration derivative will be under "Cash flows from financing activities" up to the acquisition date fair value with any excess under "Cash flows from operating activities." See Notes 10 and 11.a for additional discussion of derivatives and their fair value measurement on a recurring basis, respectively.

f. Other current assets and liabilities

Other current assets consisted of the following components as of the dates presented:

(in thousands)	December 31, 2020	December 31, 2019
Prepaid expenses and other	$ 12,166	$ 6,496
Inventory[(1)]	3,196	5,484
Other short-term asset	602	10,490
Total other current assets	$ 15,964	$ 22,470

(1) See Note 2.i for discussion of the Company's types of inventory.

Other current liabilities consisted of the following components as of the dates presented:

(in thousands)	December 31, 2020	December 31, 2019
Accrued interest payable	$ 42,401	$ 18,501
Accrued compensation and benefits	16,687	17,038
Other accrued liabilities	3,678	3,645
Total other current liabilities	$ 62,766	$ 39,184

g. Oil and natural gas properties

The Company uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain employee-related costs, incurred for the purpose of acquiring, exploring for or developing oil and natural gas properties, are capitalized and, once evaluated, depleted on a composite unit-of-production method based on estimates of proved oil, NGL and natural gas reserves. The depletion base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values. Capitalized costs include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals and other costs related to such activities. Costs, including employee-related costs, associated with production and general corporate activities are expensed in the period incurred.

The Company excludes unevaluated property acquisition costs and exploration costs from the depletion calculation until it is determined whether or not proved reserves can be assigned to the properties. The Company capitalizes a portion of its interest costs to its unevaluated properties and such costs become subject to depletion when proved reserves can be assigned to the associated properties. All items classified as unevaluated properties are assessed on a quarterly basis for possible impairment. The assessment includes consideration of the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion.

Sales of oil and natural gas properties, whether or not being depleted currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil, NGL and natural gas. See Note 6 for additional discussion of the Company's oil and natural gas properties and other property and equipment.

h. Leases

The Company recognizes operating lease right-of-use assets and operating lease liabilities on the consolidated balance sheets for operating leases with an initial term greater than 12 months. See Note 5 for further discussion of the Company's leases.

i. Inventory

The Company has the following types of inventory: (i) materials and supplies inventory used in production activities of oil and natural gas properties and midstream service assets, (ii) frac pit water inventory used in developing oil and natural gas properties and (iii) line-fill in third-party pipelines, which is the minimum volume of product in a pipeline system that enables the system to operate, and is generally not available to be withdrawn from the pipeline until the expiration of the transportation contract. All inventory is carried at the lower of cost or net realizable value ("NRV"), with cost determined using the weighted-average cost method, and is included in "Other current assets" and "Other noncurrent assets, net" on the consolidated balance sheets. The NRV for materials and supplies inventory and frac pit water inventory is estimated utilizing a replacement cost approach (Level 2). The NRV for line-fill in third-party pipelines is estimated utilizing a quoted market price adjusted for regional price differentials (Level 2). See Note 11.b for discussion of the Company's inventory impairments.

j. Debt issuance costs

Debt issuance costs, which are recorded at cost, net of amortization, are amortized over the life of the respective debt agreements utilizing the straight-line method. See Note 7.d for additional discussion of the Company's debt issuance costs.

k. Asset retirement obligations

Asset retirement obligations associated with the retirement of tangible long-lived assets are recognized as a liability in the period in which they are incurred and become determinable. The associated asset retirement costs are part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related long-lived asset is expensed through depletion, or for midstream service assets through depreciation. Changes in the liability due to the passage of time are recognized as an increase in the carrying amount of the liability and accretion expense.

The fair value of additions to the asset retirement obligation liability is measured using valuation techniques consistent with the income approach, which converts future cash flows into a single discounted amount. Significant inputs to the valuation include: (i) estimated plug and abandonment or removal and remediation cost per well or midstream service asset based on Company experience, if any, in accordance with applicable state laws (ii) estimated remaining life per well or midstream service asset, (iii) future inflation factors and (iv) the Company's average credit-adjusted risk-free rate. Inherent in the fair value calculation of asset retirement obligations are numerous assumptions and judgments including, in addition to those noted above, the ultimate settlement of these amounts, the ultimate timing of such settlement and changes in technology, regulatory, political, environmental, safety and public relations matters. To the extent future revisions to these assumptions impact the fair value of the existing asset retirement obligation liability, an adjustment will be made to the asset balance.

The Company is obligated by contractual and regulatory requirements to remove certain midstream service assets and perform other remediation of the sites where such midstream service assets are located upon the retirement of those assets. However, the fair value of the asset retirement obligation cannot currently be reasonably estimated because the settlement dates are indeterminate. The Company will record an asset retirement obligation for midstream service assets in the periods in which settlement dates are reasonably determinable.

The following table reconciles the Company's asset retirement obligation liability associated with tangible long-lived assets for the periods presented:

(in thousands)	Years ended December 31, 2020	2019
Liability at beginning of year	$ 62,718	$ 56,882
Liabilities added due to acquisitions, drilling, midstream service asset construction and other	2,252	4,755
Accretion expense(1)	4,430	4,118
Liabilities settled due to plugging and abandonment or removed due to sale	(1,074)	(3,037)
Liability at end of year	$ 68,326	$ 62,718

(1) Accretion expense is included in "Other operating expenses" on the consolidated statements of operations.

l. Fair value measurements

The carrying amounts reported on the consolidated balance sheets for cash and cash equivalents, accounts receivable, accounts payable, accrued capital expenditures, undistributed revenue and royalties and other accrued assets and liabilities approximate their fair values. See Note 2.i for the fair value assumptions used in estimating the NRV of inventory used to account for the impairment of inventory. See Note 4.c for the fair value assumptions used in estimating the fair values of assets acquired and liabilities assumed for the 2019 business combination. See Note 11 for further discussion of fair value measurements.

m. Treasury stock

Treasury stock is recorded at cost, which includes incremental direct transaction costs, and is retired upon acquisition as a result of (i) share repurchases under the share repurchase program prior to its expiration, (ii) stock exchanged to satisfy tax withholding that arises upon the lapse of restrictions on share-settled equity-based awards at the awardee's election or (iii) stock exchanged for the cost of exercise of stock options at the awardee's election.

n. Revenue recognition

Oil, NGL and natural gas sales and sales of purchased oil are generally recognized at the point in time that control of the product is transferred to the customer. Midstream service revenues are recognized over time as the customer benefits from services when provided. See Note 14 for additional discussion of revenue recognition.

o. Fees received for the operation of jointly-owned oil and natural gas properties

The Company receives fees for the operation of jointly-owned oil and natural gas properties and records such reimbursements as a reduction of general and administrative expenses.

The following table presents the fees received for the operation of jointly-owned oil and natural gas properties for the periods presented:

	Years ended December 31,		
(in thousands)	2020	2019	2018
Fees received for the operation of jointly-owned oil and natural gas properties	$ 464	$ 468	$ 412

p. Equity-based compensation awards

Equity-based compensation expense is included in "General and administrative" on the consolidated statements of operations, and includes expense for (i) restricted stock awards, stock option awards, performance share awards and the outperformance share award, which are accounted for as equity awards and are generally based on the awards' grant date fair value less an expected forfeiture rate and (ii) performance unit awards and phantom unit awards, which are accounted for as liability awards and are re-measured at each quarterly reporting period until settlement. The Company capitalizes a portion of equity-based compensation for employees who are directly involved in the acquisition, exploration and development of its oil and natural gas properties into the full cost pool. Capitalized equity-based compensation is included in "Evaluated properties" on the consolidated balance sheets. See Note 9.a for further discussion of the Company's Equity Incentive Plan.

q. Income taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating losses and tax credit carryforwards. Under this method, deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income (loss) in the period that includes the enactment date.

The Company evaluates uncertain tax positions for recognition and measurement in the consolidated financial statements. To recognize a tax position, the Company determines whether it is more likely than not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation, based on the technical merits of the position. A tax position that meets the more-likely-than-not threshold is measured to determine the amount of benefit to be recognized in the consolidated financial statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. The Company has no unrecognized tax benefits related to uncertain tax positions in the consolidated financial statements at December 31, 2020 or 2019. See Note 13 for additional information regarding the Company's income taxes.

r. Supplemental cash flow and non-cash information

The following table presents supplemental cash flow and non-cash information for the periods presented:

(in thousands)	Years ended December 31, 2020	2019	2018
Supplemental cash flow information:			
Cash paid for interest, net of $3,019, $805 and $988 of capitalized interest, respectively[(1)]	$ 77,401	$ 58,216	$ 53,981
Net cash (received) paid for income taxes[(2)]	$ (2,129)	$ (3,187)	$ 735
Supplemental non-cash investing information:			
Fair value of contingent consideration on acquisition date[(3)]	$ 225	$ 6,150	$ —
(Decrease) increase in accrued capital expenditures	$ (8,053)	$ 6,353	$ (52,746)
Capitalized share-settled equity-based compensation	$ 3,418	$ 4,470	$ 7,929
Capitalized asset retirement cost	$ 2,252	$ 4,755	$ 995

(1) See Note 7.e for additional discussion of the Company's interest expense.

(2) See Note 13 for additional discussion of the Company's income taxes.

(3) See Notes 4.a and 4.c for additional discussion of the Company's 2020 and 2019 acquisitions of oil and natural gas properties that included a contingent consideration, respectively. See Note 11.a for discussion of the quarterly remeasurement of the respective contingent consideration.

The following table presents supplemental non-cash adjustments information related to operating leases for the periods presented:

(in thousands)	Years ended December 31, 2020	2019
Right-of-use assets obtained in exchange for operating lease liabilities[(1)]	$ 2,349	$ 42,905

(1) See Note 5 for additional discussion of the Company's leases.

Note 3 New accounting standards

The Company considers the applicability and impact of all accounting standard updates ("ASU") issued by the Financial Accounting Standards Board ("FASB") to the Accounting Standards Codification ("ASC") and has determined there are no ASUs that are not yet adopted and meaningful to disclose as of December 31, 2020.

On January 1, 2020, the Company adopted ASU 2016-13 to Topic 326, *Financial Instruments—Credit Losses*, that requires an allowance for expected credit losses to be recorded against newly recognized financial assets measured at an amortized cost basis. 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 has included these factors in its analysis and determined there was minimal impact to the consolidated financial statements for the year ended December 31, 2020.

Note 4 Acquisitions and divestitures

a. 2020 Asset acquisitions

On October 16, 2020 and November 16, 2020, the Company closed a bolt-on acquisition of 2,758 and 80 net acres, respectively, including production of 210 BOE/D, in Howard County, Texas for an aggregate purchase price of $11.6 million, subject to customary post-closing purchase price adjustments.

On April 30, 2020, the Company closed an acquisition of 180 net acres in Howard County, Texas for $0.6 million. The acquisition also provides for one or more potential contingent payments to be paid by the Company if the arithmetic average of the monthly settlement WTI NYMEX prices exceed certain thresholds for the contingency period beginning on January 1, 2021 and ending on the earlier of December 31, 2022 or the date the counterparty has received the maximum consideration of $1.2 million. The fair value of this contingent consideration was $0.2 million as of the acquisition date, which was recorded as part of the basis in the oil and natural gas properties acquired and as a contingent consideration derivative liability. See Notes 10.c and 11.a for additional discussion of this contingent consideration.

On February 4, 2020, the Company closed a transaction for $22.5 million acquiring 1,180 net acres and divesting 80 net acres in Howard County, Texas.

All transaction costs were capitalized and are included in "Oil and natural gas properties, net" on the consolidated balance sheet.

b. 2020 Divestiture

On April 9, 2020, the Company closed a divestiture of 80 net acres and working interests in two producing wells in Glasscock County, Texas for $0.7 million, net of customary post-closing sales price adjustments. The divestiture was recorded as an adjustment to oil and natural gas properties pursuant to the rules governing full cost accounting. Effective at closing, the operations and cash flows of these oil and natural gas properties were eliminated from the ongoing operations of the Company, and the Company has no continuing involvement in the properties. This divestiture did not represent a strategic shift and has not had a major effect on the Company's future operations or financial results.

c. 2019 Acquisitions

Asset acquisitions

On December 12, 2019, the Company closed an acquisition of 7,360 net acres and 750 net royalty acres in Howard County, Texas for $131.7 million, net of customary closing purchase price adjustments. The acquisition provided for a potential contingent payment, where the Company was required to pay $20 million if the arithmetic average of the monthly settlement WTI NYMEX prices for each consecutive calendar month for the one-year period beginning January 1, 2020 through December 31, 2020 exceeded a certain threshold. The fair value of this contingent consideration was $6.2 million as of the acquisition date, which was recorded as part of the basis in the oil and natural gas properties acquired and as a contingent consideration derivative liability. On December 31, 2020, the contingency period ended and did not result in a payment. See Notes 10.c and 11.a for additional discussion of this contingent consideration. This acquisition was primarily financed through borrowings under the Senior Secured Credit Facility. Post-closing was finalized during the year ended December 31, 2020.

On June 20, 2019, the Company acquired 640 net acres in Reagan County, Texas for $2.9 million.

All transaction costs were capitalized and are included in "Oil and natural gas properties, net" on the consolidated balance sheet.

Business combination

On December 6, 2019, the Company closed a bolt-on acquisition of 4,475 contiguous net acres and working interests in 49 producing wells in western Glasscock County, Texas, which included net production of 1,400 BOE/D at the time of acquisition, for $64.6 million, net of customary closing purchase price adjustments. This acquisition was financed through borrowings under the Senior Secured Credit Facility. Post-closing was finalized during the year ended December 31, 2020.

This acquisition was accounted for as a business combination. Accordingly, the Company conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at the estimated acquisition date fair values, while transaction costs associated with the acquisition were expensed. The Company makes various assumptions in estimating the fair values of assets acquired and liabilities assumed. The most significant assumptions relate to the estimated fair values of evaluated and unevaluated oil and natural gas properties. The fair values of these properties were measured using a discounted cash flow model that converts future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) forecasted oil, NGL and natural gas reserve quantities; (ii) future commodity strip prices as of the closing dates adjusted for transportation and regional price differentials; (iii) forecasted ad valorem taxes, production taxes, income taxes, operating expenses and development costs; and (iv) a peer group weighted-average cost of capital rate subject to additional project-specific risk factors. To compensate for the inherent risk of estimating the value of the unevaluated properties, the discounted future net cash flows of proved undeveloped and probable reserves are reduced by additional reserve adjustment factors. These assumptions represent Level 3 inputs under the fair value hierarchy, as described in Note 11.

The following table reflects an aggregate of the final estimate of the fair values of the assets acquired and liabilities assumed in this business combination on December 6, 2019:

(in thousands)	Fair values of acquisition
Fair values of net assets:	
Evaluated oil and natural gas properties	$ 29,921
Unevaluated oil and natural gas properties	34,700
Asset retirement cost	2,728
Total assets acquired	$ 67,349
Asset retirement obligations	(2,728)
Net assets acquired	$ 64,621
Fair values of consideration paid for net assets:	
Cash consideration	$ 64,621

d. 2018 Acquisitions

During the year ended December 31, 2018, through multiple transactions, the Company acquired 966 net acres of additional leasehold and working interests in 48 producing wells in Glasscock County, Texas for an aggregate purchase price of $17.5 million, net of post-closing adjustments. These acquisitions were accounted for as asset acquisitions.

e. 2018 Divestitures

During the year ended December 31, 2018, through multiple transactions, the Company completed the sale of 3,070 net acres and working interests in 24 producing wells and associated midstream service assets in Glasscock County and Howard County in Texas to third-party buyers for an aggregate sales price of $12.0 million, net of post-closing adjustments. Of this amount, $11.5 million, net of post-closing adjustments, was recorded as adjustments to oil and natural gas properties pursuant to the rules governing full cost accounting. A loss of $1.0 million from the sale of the associated midstream service assets was included in "Loss on disposal of assets, net" in the consolidated statement of operations. Effective at the closings, the operations and cash flows of these oil and natural gas properties and midstream service assets were eliminated from the ongoing operations of the Company, and the Company has no continuing involvement in the properties. These divestitures did not represent a strategic shift and will not have a major effect on the Company's future operations or financial results.

f. Exchange of unevaluated oil and natural gas properties

From time to time, the Company exchanges undeveloped acreage with third parties. The exchanges are recorded at fair value and the difference is accounted for as an adjustment of capitalized costs with no gain or loss recognized pursuant to the rules governing full cost accounting, unless such adjustment would significantly alter the relationship between capitalized costs and proved reserves of oil, NGL and natural gas.

Note 5 Leases

a. Impact of ASC 842 adoption

The Company determines whether a contract is or contains a lease at inception of the contract, based on answers to a series of questions that address whether an identified asset exists and whether the Company has the right to obtain substantially all of the benefit of the asset and to control its use over the full term of the agreement. When available, the Company uses the rate implicit in the lease to discount lease payments to present value; however, most of the Company's leases do not provide a readily determinable implicit rate. In such cases, the Company is required to use its incremental borrowing rate ("IBR"). The Company determines its IBR using both a "credit notching" approach and a "recovery method" approach. The results of these

approaches are then weighted equally and averaged in order to determine the concluded IBR. This concluded IBR is utilized to discount the lease payments based on information available at lease commencement. There are no material residual value guarantees, nor any restrictions or covenants included in the Company's lease agreements.

Mineral leases, including oil and natural gas leases granting the right to explore for those natural resources and rights to use the land in which those natural resources are contained, are not included in the scope of ASC 842.

The Company has recognized operating lease right-of-use assets and operating lease liabilities on the consolidated balance sheets for leases of commercial real estate with lease terms extending into 2027 and drilling, completion, production and other equipment leases with lease terms extending into 2022. The Company has various other drilling, completion and production equipment leases on a short-term basis which are reflected in short-term lease costs.

The Company's lease costs include those that are recognized in net income (loss) during the period and capitalized as part of the cost of another asset in accordance with other GAAP.

The lease costs related to drilling, completion and production activities are reflected at the Company's net ownership, which is consistent with the principals of proportional consolidation, and lease commitments are reflected on a gross basis. As of December 31, 2020 and 2019, the Company had an average working interest of 97% in Laredo-operated active productive wells.

Certain of the Company's leases include provisions for variable payments. These variable payments are typically determined based on a measure of throughput, actual days or another measure of usage. For our drilling rigs, the variable lease costs include the payments that depend on the performance or usage of the underlying asset, the costs to move and the costs to repair the drilling rigs. For certain of our commercial office buildings, utilities and common area, the variable lease costs are the variable maintenance charges. For our equipment leases, the variable lease costs are the amounts incurred under our contracts that are beyond the minimum rental fee, inclusive of maintenance.

The Company subleases certain office space to third parties but remains the primary obligor under the head lease. The lease terms on those subleases each contain renewal options that do not extend past the term of the head lease. The subleases do not contain residual value guarantees. Sublease income is recognized based on the contract terms and, upon the adoption of ASC 842, is included as a reduction of lease expense under the head lease.

Certain of the Company's operating lease right-of-use asset classes include options to renew on a month-to-month basis. The Company considers contract-based, asset-based, market-based and entity-based factors to determine the term over which it is reasonably certain to extend the lease in determining its right-of-use assets and liabilities.

The Company's material leases do not include options to purchase the leased property.

The Company does not have any significant finance leases.

b. Lease costs

The following table presents components of total lease costs, net for the periods presented:

	Years ended December 31,	
(in thousands)	2020	2019
Operating lease costs[(1)]	$ 15,094	$ 16,530
Short-term lease costs[(2)]	82,576	160,547
Variable lease costs[(3)]	10,218	2,683
Sublease income	(1,032)	(988)
Total lease costs, net	$ 106,856	$ 178,772

(1) Amounts represent straight-line costs associated with the Company's operating lease right-of-use assets.

(2) Amounts include costs associated with the Company's short-term leases that are not included in the calculation of lease liabilities and right-of-use assets and, therefore, are not recorded on the consolidated balance sheets as such.

(3) Amounts are primarily comprised of the non-lease service component of drilling rig commitments above the minimum required payments, and are not included in the calculation of lease liabilities and right-of-use assets. Both the minimum required payments and the non-lease service component of the drilling rig commitments are capitalized as additions to oil and natural gas properties.

c. Operating leases

Supplemental cash flow information

The following table presents cash paid for amounts included in the measurement of operating lease liabilities, which may not agree to operating lease costs due to timing of cash payments and costs incurred for the periods presented:

	Years ended December 31,	
(in thousands)	2020	2019
Operating cash flows from operating leases	$ 5,910	$ 5,728
Investing cash flows from operating leases[(1)]	$ 9,425	$ 11,103

(1) Amounts associated with drilling operations are capitalized as additions to oil and natural gas properties.

Lease terms and discount rates

The following table presents the weighted-average remaining lease term and weighted-average discount rate for operating leases as of the dates presented:

	December 31, 2020	December 31, 2019
Weighted-average remaining lease term	2.87 years	3.07 years
Weighted-average discount rate	7.72 %	8.05 %

Maturities

The following table reconciles the undiscounted cash flows for recognized operating lease liabilities for each of the first five years and the total remaining years to the operating lease liabilities recorded on the consolidated balance sheet as of the date presented:

(in thousands)	December 31, 2020
2021	$ 12,831
2022	4,551
2023	1,360
2024	1,271
2025	1,296
Thereafter	1,988
Total minimum lease payments	23,297
Less: lease liability expense	(2,658)
Present value of future minimum lease payments	20,639
Less: current operating lease liabilities	(11,721)
Noncurrent operating lease liabilities	$ 8,918

Other information

See Note 2.r for disclosure of supplemental non-cash adjustments information related to operating leases. See Note 17.a for disclosure of related-party lease amounts.

d. Disclosure for the periods prior to adoption of ASC 842

See Note 14.a in the 2018 Annual Report for discussion of the Company's lease commitments and accounting for rental expense and rental income prior to the adoption of ASC 842. The Company adopted ASC 842 under the modified retrospective approach on January 1, 2019.

Note 6 Property and equipment

a. Oil and natural gas properties

See Note 2.g for discussion of the Company's significant accounting policies for oil and natural gas properties.

Oil and natural gas properties consisted of the following components as of the dates presented:

(in thousands)	December 31, 2020	December 31, 2019
Evaluated properties	$ 7,874,932	$ 7,421,799
Unevaluated properties not being depleted	70,020	142,354
Less accumulated depletion and impairment	(6,817,949)	(5,725,114)
Total oil and natural gas properties, net	$ 1,127,003	$ 1,839,039

The following table presents capitalized employee-related costs incurred in the acquisition, exploration and development of oil and natural gas properties for the periods presented:

	Years ended December 31,		
(in thousands)	2020	2019	2018
Capitalized employee-related costs	$ 18,954	$ 18,299	$ 25,372

See Note 20.a for total costs incurred in the acquisition, exploration and development of oil and natural gas properties, which includes the aforementioned capitalized employee-related costs.

The following table presents depletion expense, which is included in "Depletion, depreciation and amortization" on the consolidated statements of operations, and depletion expense per BOE sold of evaluated oil and natural gas properties for the periods presented:

	Years ended December 31,		
(in thousands except per BOE data)	2020	2019	2018
Depletion expense of evaluated oil and natural gas properties	$ 203,492	$ 250,857	$ 196,458
Depletion expense per BOE sold	$ 6.34	$ 8.50	$ 7.90

The full cost ceiling is based principally on the estimated future net cash flows from proved oil, NGL and natural gas reserves, which exclude the effect of the Company's commodity derivative transactions, discounted at 10%. The Securities and Exchange Commission ("SEC") guidelines require companies to use the unweighted arithmetic average first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period before differentials ("Benchmark Prices"). The Benchmark Prices are then adjusted for quality, certain transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the delivery point ("Realized Prices") without giving effect to the Company's commodity derivative transactions. The Realized Prices are utilized to calculate the estimated future net cash flows in the full cost ceiling calculation. Significant inputs included in the calculation of discounted cash flows used in the impairment analysis include the Company's estimate of operating and development costs, anticipated production of proved reserves and other relevant data. In the event the unamortized cost of evaluated oil and natural gas properties being depleted exceeds the full cost ceiling, as defined by the SEC, the excess is expensed in the period such excess occurs. Once incurred, a write-down of oil and natural gas properties is not reversible.

The following table presents the Benchmark Prices and the Realized Prices as of the dates presented:

	December 31, 2020	December 31, 2019	December 31, 2018
Benchmark Prices:			
Oil ($/Bbl)	$ 36.04	$ 52.19	$ 62.04
NGL ($/Bbl)[1]	$ 16.63	$ 21.14	$ 31.46
Natural gas ($/MMBtu)	$ 1.21	$ 0.87	$ 1.76
Realized Prices:			
Oil ($/Bbl)	$ 37.69	$ 52.12	$ 59.29
NGL ($/Bbl)	$ 7.43	$ 12.21	$ 21.42
Natural gas ($/Mcf)	$ 0.79	$ 0.53	$ 1.38

(1) Based on the Company's average composite NGL barrel.

The following table presents full cost ceiling impairment expense, which is included in "Impairment expense" on the consolidated statements of operations for the periods presented:

	Years ended December 31,		
(in thousands)	2020	2019	2018
Full cost ceiling impairment expense	$ 889,453	$ 620,565	$ —

b. Midstream service assets

Midstream service assets, which consist of oil and natural gas pipeline gathering assets, related equipment, oil delivery stations, water storage and treatment facilities and their related asset retirement cost, are recorded at cost, net of impairment. See Note 2.k for discussion regarding midstream service asset retirement cost. Depreciation of assets is recorded using the straight-line method based on estimated useful lives of 10 to 20 years, as applicable. Expenditures for significant betterments or renewals, which extend the useful lives of existing fixed assets, are capitalized and depreciated. Upon retirement or disposition, the cost and related accumulated depreciation are removed from the accounts and any gain or loss is recognized in "Loss on disposal of assets, net" in the consolidated statements of operations.

Midstream service assets consisted of the following components as of the dates presented:

(in thousands)	December 31, 2020	December 31, 2019
Midstream service assets	$ 181,718	$ 180,932
Less accumulated depreciation and impairment	(69,021)	(52,254)
Total midstream service assets, net	$ 112,697	$ 128,678

The following table presents depreciation of midstream service assets for the periods presented:

	Years ended December 31,		
(in thousands)	2020	2019	2018
Depreciation of midstream service assets	$ 9,838	$ 10,206	$ 10,144

c. Other fixed assets

Other fixed assets are recorded at cost and are subject to depreciation and amortization. Land is recorded at cost and is not subject to depreciation. Depreciation and amortization of other fixed assets is provided using the straight-line method based on estimated useful lives of three to ten years, as applicable. Leasehold improvements are capitalized and amortized over the shorter of the estimated useful lives of the assets or the terms of the related leases. Expenditures for significant betterments or renewals, which extend the useful lives of existing fixed assets, are capitalized and depreciated. Upon retirement or disposition, the cost and related accumulated depreciation and amortization are removed from the accounts and any gain or loss is recognized in "Loss on disposal of assets, net" in the consolidated statements of operations.

Other fixed assets consisted of the following components as of the dates presented:

(in thousands)	December 31, 2020	December 31, 2019
Vehicles	$ 9,852	$ 9,407
Computer hardware and software	9,388	9,881
Leasehold improvements	7,125	7,619
Buildings	6,982	7,055
Other	4,107	3,932
Depreciable total	37,454	37,894
Less accumulated depreciation and amortization	(24,344)	(23,649)
Depreciable total, net	13,110	14,245
Land	18,901	18,259
Total other fixed assets, net	$ 32,011	$ 32,504

The following table presents depreciation and amortization of other fixed assets for the periods presented:

	Years ended December 31,		
(in thousands)	2020	2019	2018
Depreciation and amortization of other fixed assets	$ 3,771	$ 4,683	$ 6,075

Note 7 Debt

a. January 2025 Notes and January 2028 Notes

On January 24, 2020, the Company completed an offer and sale (the "Offering") of $600.0 million in aggregate principal amount of 9.500% senior unsecured notes due 2025 (the "January 2025 Notes") and $400.0 million in aggregate principal amount of 10.125% senior unsecured notes due 2028 (the "January 2028 Notes"). Interest for both the January 2025 Notes and January 2028 Notes is payable semi-annually, in cash in arrears on January 15 and July 15 of each year. The first interest payment was made on July 15, 2020, and consisted of interest from closing to that date. The terms of the January 2025 Notes and January 2028 Notes include covenants, which are in addition to but different than similar covenants in the Senior Secured Credit Facility, which limit the Company's ability to incur indebtedness, make restricted payments, grant liens and dispose of assets.

The January 2025 Notes and January 2028 Notes are fully and unconditionally guaranteed on a senior unsecured basis by LMS, GCM and certain of the Company's future restricted subsidiaries, subject to certain automatic customary releases, including the sale, disposition or transfer of all of the capital stock or of all or substantially all of the assets of a subsidiary guarantor to one or more persons that are not the Company or a restricted subsidiary, exercise of legal defeasance or covenant defeasance options or satisfaction and discharge of the applicable indenture, designation of a subsidiary guarantor as a non-guarantor restricted subsidiary or as an unrestricted subsidiary in accordance with the applicable indenture, release from guarantee under the Senior Secured Credit Facility, or liquidation or dissolution (collectively, the "Releases").

The Company received net proceeds of $982.0 million from the Offering, after deducting underwriting discounts and commissions and estimated offering expenses. The proceeds from the Offering were used (i) to fund Tender Offers (defined below) for the Company's January 2022 Notes and March 2023 Notes (defined below), (ii) to repay the Company's January 2022 Notes and March 2023 Notes that remained outstanding after settling the Tender Offers and (iii) for general corporate purposes, including repayment of a portion of the borrowings outstanding under the Company's Senior Secured Credit Facility.

In November 2020, the Company's board of directors authorized a $50.0 million bond repurchase program. During the year ended December 31, 2020, the Company repurchased $22.1 million in aggregate principal amount of the January 2025 Notes and $39.0 million in aggregate principal amount of the January 2028 Notes for aggregate consideration of $13.9 million and $24.2 million, respectively, plus accrued and unpaid interest. The Company recognized a gain on extinguishment of $22.3 million related to the difference between the consideration paid and the net carrying amounts of the extinguished portions of the January 2025 Notes and January 2028 Notes.

b. January 2022 Notes and March 2023 Notes

On January 23, 2014, the Company completed an offering of $450.0 million in aggregate principal amount of 5 5/8% senior unsecured notes due 2022 (the "January 2022 Notes"). The January 2022 Notes were due to mature on January 15, 2022 and bore an interest rate of 5 5/8% per annum, payable semi-annually, in cash in arrears on January 15 and July 15 of each year, commencing July 15, 2014. The January 2022 Notes were fully and unconditionally guaranteed on a senior unsecured basis by LMS, GCM and certain of the Company's future restricted subsidiaries, subject to certain Releases.

On March 18, 2015, the Company completed an offering of $350.0 million in aggregate principal amount of 6 1/4% senior unsecured notes due 2023 (the "March 2023 Notes"). The March 2023 Notes were due to mature on March 15, 2023 and bore an interest rate of 6 1/4% per annum, payable semi-annually, in cash in arrears on March 15 and September 15 of each year, commencing September 15, 2015. The March 2023 Notes were fully and unconditionally guaranteed on a senior unsecured basis by LMS, GCM and certain of the Company's future restricted subsidiaries, subject to certain Releases.

On January 6, 2020, the Company commenced cash tender offers and consent solicitations for any or all of its outstanding January 2022 Notes and March 2023 Notes (collectively, the "Tender Offers"). On January 24, 2020 and February 6, 2020, the Company settled the Tender Offers for the principal outstanding amounts of $428.9 million and $299.4 million, respectively, for consideration for tender offers and early tender premiums of $431.6 million and $304.1 million for the January 2022 Notes and March 2023 Notes, respectively, plus accrued and unpaid interest. On January 29, 2020, the Company redeemed the remaining $21.1 million of January 2022 Notes not tendered under the Tender Offers at a redemption price of 100.000% of the principal amount thereof, plus accrued and unpaid interest. On March 15, 2020, the Company redeemed the remaining $50.6 million of March 2023 Notes not tendered under the Tender Offers at a redemption price of 101.563% of the principal amount thereof, plus accrued and unpaid interest. The Company recognized a loss on extinguishment of $13.3 million related to the difference between the consideration for tender offers, early tender premiums and redemption prices and the net carrying amounts of the extinguished January 2022 Notes and March 2023 Notes.

c. Senior Secured Credit Facility

The Fifth Amended and Restated Credit Agreement (as amended, the "Senior Secured Credit Facility") matures on April 19, 2023. As of December 31, 2020, the Senior Secured Credit Facility had a maximum credit amount of $2.0 billion and a borrowing base and an aggregate elected commitment of $725.0 million each, with $255.0 million outstanding and was subject to an interest rate of 2.688%. The borrowing base is subject to a semi-annual redetermination occurring by May 1 and November 1 of each year based on the lenders' evaluation of the Company's oil, NGL and natural gas reserves. As defined in the Senior Secured Credit Facility, (i) the Adjusted Base Rate advances under the facility bear interest payable quarterly at an

Adjusted Base Rate plus applicable margin, which ranges from 1.25% to 2.25%, based on the ratio of outstanding revolving credit to the borrowing base under the Senior Secured Credit Facility; and (ii) the Eurodollar advances under the facility bear interest, at the Company's election, at the end of one-month, two-month, three-month, six-month or, to the extent available, 12-month interest periods (and in the case of six-month and 12-month interest periods, every three months prior to the end of such interest period) at an Adjusted London Interbank Offered Rate plus an applicable margin, which ranges from 2.25% to 3.25%, based on the ratio of outstanding revolving credit to the borrowing base under the Senior Secured Credit Facility. Laredo is required to pay a quarterly commitment fee on the unused portion of the financial institutions' commitment of 0.375% to 0.5%, based on the ratio of outstanding revolving credit to the aggregate elected commitment under the Senior Secured Credit Facility.

The Senior Secured Credit Facility is secured by a first-priority lien on Laredo and the Guarantors' assets and stock, including oil and natural gas properties constituting at least 85% of the present value of the Company's proved reserves. Further, the Company is subject to various financial and non-financial covenants on a consolidated basis, including a current ratio at the end of each calendar quarter, of not less than 1.00 to 1.00. As defined by the Senior Secured Credit Facility, the current ratio represents the ratio of current assets to current liabilities, inclusive of available capacity and exclusive of current balances associated with derivative positions. Additionally, the Company must maintain as of the last day of each calendar quarter a ratio of (a) its total debt (excluding reimbursement obligations in respect of undrawn letters of credit, if no loans are outstanding under the Senior Secured Credit Facility) minus a maximum of $50 million of unrestricted and unencumbered cash and cash equivalents, to (b) "Consolidated EBITDAX," as defined in the Senior Secured Credit Facility, for any period of four consecutive calendar quarters ending on the last day of such applicable calendar quarter of not greater than 4.25 to 1.00 through the quarterly period ended September 30, 2020, and 4.00 to 1.00 beginning on December 31, 2020. The Company was in compliance with these covenants for all periods presented. The Company's measurements of Adjusted EBITDA (non-GAAP) for financial reporting differs from the measurement used for compliance under its debt agreements.

Additionally, the Senior Secured Credit Facility provides for the issuance of letters of credit, limited to the lesser of total capacity or $80.0 million. As of December 31, 2020 and 2019, the Company had one letter of credit outstanding of $44.1 million and $14.7 million, respectively, under the Senior Secured Credit Facility.

See Note 19.a for discussion of a borrowing and payment on the Senior Secured Credit Facility subsequent to December 31, 2020.

d. Debt issuance costs

The following table presents debt issuance costs capitalized and debt issuance costs write-offs for the periods presented:

	Years ended December 31,		
(in thousands)	2020	2019	2018
Debt issuance costs capitalized(1)	$ 18,479	$ —	$ 2,469
Debt issuance costs write-offs(2)	$ 6,163	$ 935	$ —

(1) The Company capitalized $0.1 million and $2.5 million in debt issuance costs during the years ended December 31, 2020 and 2018, respectively, in connection with entering into amendments to the Senior Secured Credit Facility pursuant to the semi-annual redeterminations. The Company capitalized $18.4 million in debt issuance costs during the year ended December 31, 2020 in connection with the issuance of the January 2025 Notes and January 2028 Notes.

(2) The Company wrote off $1.1 million and $0.9 million of debt issuance costs during the years ended December 31, 2020 and 2019, respectively, which are the "Write-off of debt issuance costs" on the consolidated statements of operations, in connection with reductions in borrowing base and aggregate elected commitment under the Senior Secured Credit Facility pursuant to the semi-annual redeterminations. The Company wrote off $5.1 million in debt issuance costs during the year ended December 31, 2020, which are included in "Gain on extinguishment of debt, net" on the consolidated statement of operations, in connection with the extinguishment of the January 2022 Notes and March 2023 Notes and portions of the January 2025 Notes and January 2028 Notes.

The Company had total debt issuance costs of $17.0 million and $9.0 million, net of accumulated amortization of $22.1 million and $27.5 million, as of December 31, 2020 and 2019, respectively. Debt issuance costs related to the

Company's January

2025 and January 2028 Notes are included in "Long-term debt, net" on the consolidated balance sheets. Debt issuance costs related to the Senior Secured Credit Facility are included in "Other noncurrent assets, net" on the consolidated balance sheets. Debt issuance costs are amortized on a straight-line basis over the respective terms of the notes and the Senior Secured Credit Facility. See Note 7.f for additional discussion of debt issuance costs.

The following table presents future amortization expense of debt issuance costs:

(in thousands)	December 31, 2020
2021	4,031
2022	4,031
2023	3,362
2024	3,027
2025	865
Thereafter	1,717
Total	17,033

e. Interest expense

The following table presents amounts that have been incurred and charged to interest expense:

	Years ended December 31,		
(in thousands)	2020	2019	2018
Cash payments for interest	$ 80,420	$ 59,021	$ 54,969
Amortization of debt issuance costs and other adjustments	3,708	3,111	3,655
Change in accrued interest	23,900	220	268
Interest costs incurred	108,028	62,352	58,892
Less capitalized interest	(3,019)	(805)	(988)
Total interest expense	$ 105,009	$ 61,547	$ 57,904

f. Long-term debt, net

The following table presents the Company's long-term debt and debt issuance costs, net included in "Long-term debt, net" on the consolidated balance sheets as of the dates presented:

	December 31, 2020			December 31, 2019		
(in thousands)	Long-term debt	Debt issuance costs, net	Long-term debt, net	Long-term debt	Debt issuance costs, net	Long-term debt, net
January 2022 Notes	$ —	$ —	$ —	$ 450,000	$ (2,034)	$ 447,966
March 2023 Notes	—	—	—	350,000	(2,549)	347,451
January 2025 Notes	577,913	(8,676)	569,237	—	—	—
January 2028 Notes	361,044	(6,015)	355,029	—	—	—
Senior Secured Credit Facility(1)	255,000	—	255,000	375,000	—	375,000
Total	$ 1,193,957	$ (14,691)	$ 1,179,266	$ 1,175,000	$ (4,583)	$ 1,170,417

(1) Debt issuance costs, net related to the Senior Secured Credit Facility of $2.3 million and $4.5 million as of December 31, 2020 and 2019, respectively, are included in "Other noncurrent assets, net" on the consolidated balance sheets.

Note 8 Stockholders' equity

a. Reverse stock split and Authorized Share Reduction

On March 17, 2020, the board of directors authorized an amendment to the Company's amended and restated certificate of incorporation ("Certificate of Incorporation") to effect, at the discretion of the board of directors (i) a reverse stock split that would reduce the number of shares of outstanding common stock in accordance with a ratio to be determined by the board

of directors within a range of 1-for-5 and 1-for-20 currently outstanding and (ii) a reduction of the number of authorized shares of common stock by a corresponding proportion ("Authorized Share Reduction").

On May 14, 2020, after receiving stockholder approval of the amendment to the Company's Certificate of Incorporation to effect, at the discretion of the board of directors, the reverse stock split and the Authorized Share Reduction, the board of directors approved the implementation of the reverse stock split at a ratio of 1-for-20 currently outstanding shares of common stock, and the related corresponding Authorized Share Reduction.

On June 1, 2020, the amendment to the Company's Certificate of Incorporation became effective and effected the 1-for-20 reverse stock split of the Company's issued and outstanding common stock and the related Authorized Share Reduction from 450,000,000 to 22,500,000 authorized shares, par value $0.01 per share, with authorized shares of preferred stock remaining unchanged at 50,000,000, par value $0.01 per share, for a total of 72,500,000 shares of capital stock. See Note 9.a for discussion of the Laredo Petroleum, Inc. Omnibus Equity Incentive Plan (the "Equity Incentive Plan"), that proportionately reduced the number of shares that may be granted.

b. Share repurchase program

In February 2018, the Company's board of directors authorized a $200.0 million share repurchase program commencing in February 2018. The repurchase program expired in February 2020. During the year ended December 31, 2018, the Company repurchased 552,437 shares of common stock at a weighted-average price of $175.60 per common share, retroactively adjusted for the Company's 1-for-20 reverse stock split, for a total of $97.1 million under this program. All shares were retired upon repurchase. There were no share repurchases under this program during the years ended December 31, 2020 or 2019.

Note 9 Compensation plans

a. Equity Incentive Plan

The Equity Incentive Plan provides for the granting of incentive awards in the form of restricted stock awards, stock option awards, performance share awards, outperformance share awards, performance unit awards, phantom unit awards and other awards. On June 1, 2020, in connection with the effectiveness of the reverse stock split and Authorized Share Reduction, the board of directors approved and adopted an amendment to the Equity Incentive Plan to proportionately adjust the limitations on awards that may be granted under the Equity Incentive Plan. Following the amendment, an aggregate of 1,492,500 shares may be issued under the Equity Incentive Plan. See Note 8.a for additional discussion of the reverse stock split and Authorized Share Reduction.

See Note 2.p for discussion of the Company's significant accounting policies for equity-based compensation awards.

Restricted stock awards

All service vesting restricted stock awards are treated as issued and outstanding in the consolidated financial statements. Per the award agreement terms, if employment is terminated prior to the restriction lapse date for reasons other than death or disability, the restricted stock awards are forfeited and canceled and are no longer considered issued and outstanding. If the termination of employment is by reason of death or disability, all of the holder's restricted stock will automatically vest. Restricted stock awards granted to employees vest in a variety of schedules that mainly include (i) 33%, 33% and 34% vesting per year beginning on the first anniversary of the grant date and (ii) full vesting on the first anniversary of the grant date. Restricted stock awards granted to non-employee directors vest immediately on the grant date.

The following table reflects the restricted stock award activity for the years presented:

(in thousands, except for weighted-average grant-date fair value)	Restricted stock awards[1]	Weighted-average grant-date fair value (per share)[1]
Outstanding as of December 31, 2017	158	$ 256.20
Granted	166	$ 166.80
Forfeited	(18)	$ 202.60
Vested	(96)	$ 238.40
Outstanding as of December 31, 2018	210	$ 198.20
Granted	381	$ 65.20
Forfeited	(178)	$ 102.20
Vested	(138)	$ 178.40
Outstanding as of December 31, 2019	275	$ 85.80
Granted	238	$ 16.54
Forfeited	(48)	$ 53.51
Vested[2]	(156)	$ 71.25
Outstanding as of December 31, 2020	309	$ 44.88

(1) Shares and per share data have been retroactively adjusted to reflect the Company's 1-for-20 reverse stock split effective June 1, 2020, as described in Note 8.a. Weighted-average grant-date fair values for outstanding awards are based on actual amounts and are not calculated using the rounded numbers presented.

(2) The aggregate intrinsic value of vested restricted stock awards for the year ended December 31, 2020 was $3.3 million.

The Company utilizes the closing stock price on the grant date to determine the fair value of restricted stock awards. As of December 31, 2020, unrecognized equity-based compensation related to the restricted stock awards expected to vest was $7.4 million. Such cost is expected to be recognized over a weighted-average period of 1.50 years.

Stock option awards

The following table reflects the stock option award activity for the years presented:

(in thousands, except for weighted-average exercise price and weighted-average remaining contractual term)	Stock option awards[1]	Weighted-average exercise price (per option)[1]	Weighted-average remaining contractual term (years)
Outstanding as of December 31, 2017	132	$ 254.00	7.12
Exercised	(1)	$ 82.00	
Expired or canceled	(3)	$ 378.40	
Forfeited	(1)	$ 184.60	
Outstanding as of December 31, 2018	127	$ 253.80	5.99
Exercised	(1)	$ 82.00	
Expired or canceled	(92)	$ 271.00	
Forfeited	(17)	$ 172.20	
Outstanding as of December 31, 2019	17	$ 251.20	5.00
Expired or canceled	(6)	$ 238.38	
Outstanding as of December 31, 2020	11	$ 257.42	4.00
Vested and exercisable as of December 31, 2020[2]	10	$ 256.68	3.94
Expected to vest as of December 31, 2020[3]	1	$ 282.40	6.13

(1) Options and per option data have been retroactively adjusted to reflect the Company's 1-for-20 reverse stock split effective June 1, 2020, as described in Note 8.a. Weighted-average exercise prices for outstanding options are based on actual amounts and are not calculated using the rounded numbers presented.

(2) The vested and exercisable stock option awards as of December 31, 2020 had no intrinsic value.

(3) The stock option awards expected to vest as of December 31, 2020 had no intrinsic value.

The Company utilizes the Black-Scholes option pricing model to determine the fair value of stock option awards and recognizes the associated expense on a straight-line basis over the four-year requisite service period of the awards. As of December 31, 2020, unrecognized equity-based compensation related to stock option awards expected to vest was de minimis. Such cost is expected to be recognized over a weighted-average period of 0.17 years.

Stock option awards granted to employees vest and become exercisable in four equal installments on each of the four anniversaries of the grant date, in accordance with the following schedule:

Full years of continuous employment following grant date	Incremental percentage of option exercisable	Cumulative percentage of option exercisable
Less than one	— %	— %
One	25 %	25 %
Two	25 %	50 %
Three	25 %	75 %
Four	25 %	100 %

Unless employment is terminated sooner, the vested stock option award will expire if and to the extent it is not exercised within 10 years from the grant date. The unvested portion of a stock option award shall forfeit upon termination of employment, and the vested portion of a stock option award shall remain exercisable for (i) one year following termination of employment by reason of the holder's death or disability, but not later than the expiration of the option period, or (ii) 90 days following termination of employment for any reason other than the holder's death or disability, and other than the holder's termination of employment for cause. The vested but unexercised portion of a stock option award shall expire upon the termination of the option holder's employment or service by the Company for cause.

Performance share awards

Performance share awards, which the Company has determined are equity awards, are subject to a combination of market, performance and service vesting criteria. For portions of awards with market criteria, which include: (i) the relative three-year total shareholder return ("TSR") comparing the Company's shareholder return to the shareholder return of the peer group specified in each award agreement ("RTSR Performance Percentage"), and (ii) the Company's absolute three-year total shareholder return ("ATSR Appreciation"), a Monte Carlo simulation prepared by an independent third party is utilized to determine the grant-date (or modification date) fair value, and the associated expense is recognized on a straight-line basis over the three-year requisite service period of the awards. For portions of awards with performance criteria, which is the Company's three-year return on average capital employed ("ROACE Percentage"), the fair value is equal to the Company's closing stock price on the grant date (or modification date), and for each reporting period, the associated expense fluctuates and is adjusted based on an estimated payout of the number of shares of common stock to be delivered on the payment date for the three-year performance period. Any shares earned under performance share awards are expected to be issued in the first quarter following the completion of the respective requisite service periods based on the achievement of certain market and performance criteria, and the payout can range from 0% to 200%. Per the award agreement terms, if employment is terminated prior to the restriction lapse date for reasons other than death or disability, the performance share awards are forfeited and canceled. If the termination of employment is by reason of death or disability, and the market and performance criteria are satisfied, then the holder of the earned performance share awards will receive a prorated number of shares based on the number of days the participant was employed with the Company during the performance period.

The following table reflects the performance share award activity for the years presented:

(in thousands, except for weighted-average grant-date fair value)	Performance share awards[1]	Weighted-average grant-date fair value (per share)[1]
Outstanding as of December 31, 2017	137	$ 355.40
Granted[2]	70	$ 184.40
Forfeited	(12)	$ 298.60
Lapsed[3]	(23)	$ 324.60
Outstanding as of December 31, 2018	172	$ 274.80
Granted[2]	29	$ 50.40
Converted from performance unit awards[2][4]	78	$ 74.80
Forfeited	(87)	$ 209.60
Lapsed[5]	(77)	$ 346.20
Outstanding as of December 31, 2019	115	$ 106.80
Forfeited	(10)	$ 110.94
Lapsed[6]	(8)	$ 379.20
Outstanding as of December 31, 2020	97	$ 84.06

(1) Shares and per share data have been retroactively adjusted to reflect the Company's 1-for-20 reverse stock split effective June 1, 2020, as described in Note 8.a. Weighted-average grant-date fair values for outstanding awards are based on actual amounts and are not calculated using the rounded numbers presented.

(2) The amounts potentially payable in the Company's common stock at the end of the requisite service period for the performance share awards granted on February 16, 2018, February 28, 2019 and June 3, 2019 will be determined based on three criteria: (i) RTSR Performance Percentage, (ii) ATSR Appreciation and (iii) ROACE Percentage. The RTSR Performance Percentage, ATSR Appreciation and ROACE Percentage will be used to identify the "RTSR Factor," the "ATSR Factor" and the "ROACE Factor," respectively, which are used to compute the "Performance Multiple" and ultimately to determine the number of shares to be delivered on the payment date. In computing the Performance Multiple, the RTSR Factor is given a 1/4 weight, the ATSR Factor a 1/4 weight and the ROACE Factor a 1/2 weight. The performance share awards granted on February 16, 2018 had a performance period of January 1, 2018 to December 31, 2020, resulting in the Company finishing in the 30th percentile of its peer group for relative TSR, and a portion of the units will be converted into the Company's common stock during the first quarter of 2021 based on the achieved

market and performance criteria. The performance share awards granted on February 28, 2019 and June 3, 2019 have a performance period of January 1, 2019 to December 31, 2021.

(3) The performance share awards granted on February 27, 2015 had a performance period of January 1, 2015 to December 31, 2017 and, as their market criteria were not satisfied, resulted in a TSR modifier of 0% based on the Company finishing in the 36th percentile of its peer group for relative TSR. As such, the granted units lapsed and were not converted into the Company's common stock during the first quarter of 2018.

(4) On May 16, 2019, the board of directors elected to change the form of payment from cash to common stock for the awards granted on February 28, 2019. This change in election triggered modification accounting, and the awards, formerly accounted for as liability awards, were converted to equity awards and, accordingly, new fair values were determined based on the May 16, 2019 modification date.

(5) The performance share awards granted on May 25, 2016 had a performance period of January 1, 2016 to December 31, 2018 and, as their market criteria were not satisfied, resulted in a TSR modifier of 0% based on the Company finishing in the ninth percentile of its peer group for relative TSR. As such, the granted units lapsed and were not converted into the Company's common stock during the first quarter of 2019.

(6) The performance share awards granted on February 17, 2017 had a performance period of January 1, 2017 to December 31, 2019 and, as their market criteria were not satisfied, resulted in a TSR modifier of 0% based on the Company finishing in the 15th percentile of its peer group for relative TSR. As such, the granted units lapsed and were not converted into the Company's common stock during the first quarter of2020.

As of December 31, 2020, unrecognized equity-based compensation related to the performance share awards expected to vest was $2.9 million. Such cost is expected to be recognized over a weighted-average period of 1.13 years.

The following table presents (i) the fair values per performance share and the assumptions used to estimate these fair values per performance share and (ii) the expense per performance share, which is the fair value per performance share adjusted for the estimated payout of the performance criteria, for the outstanding performance share awards as of December 31, 2020 for the grant dates presented:

	June 3, 2019[1]	February 28, 2019[1][2]	February 16, 2018[1]
Market Criteria:			
(1/4) RTSR Factor + (1/4) ATSR Factor:			
Fair value assumptions:			
Remaining performance period on grant date	2.58 years	2.63 years	2.87 years
Risk-free interest rate[3]	1.78 %	2.14 %	2.34 %
Dividend yield	— %	— %	— %
Expected volatility[4]	55.45 %	55.01 %	65.49 %
Closing stock price on grant date	$ 51.80	$ 69.80	$ 167.20
Grant-date fair value per performance share	$ 49.00	$ 79.61	$ 201.65
Expense per performance share as of December 31, 2020	$ 49.00	$ 79.61	$ 201.65
Performance Criteria:			
(1/2) ROACE Factor:			
Fair value assumptions:			
Closing stock price on grant date	$ 51.80	$ 69.80	$ 167.20
Grant-date fair value per performance share	$ 51.80	$ 69.80	$ 167.20
Estimated payout for expense as of December 31, 2020	170 %	170 %	61 %
Expense per performance share as of December 31, 2020[5]	$ 88.06	$ 118.66	$ 102.16
Combined:			
Grant-date fair value per performance share[6]	$ 50.40	$ 74.71	$ 184.43
Expense per performance share as of December 31, 2020[7]	$ 68.53	$ 99.14	$ 151.91

(1) Per share data has been retroactively adjusted to reflect the Company's 1-for-20 reverse stock split effective June 1, 2020, as described in Note 8.a. Grant-date fair values and expense are based on actual amounts and are not calculated using the rounded numbers presented.

(2) The fair value assumptions of the performance share awards granted on February 28, 2019 are based on the May 16, 2019 modification date. The total incremental compensation expense resulting from the modification of $1.0 million, which will be recognized over the life of the awards, is calculated utilizing (i) the difference between the March 31, 2019 fair value and the May 16, 2019 fair value and (ii) the outstanding quantity of the converted performance share awards as of June 30, 2019. Such expense excludes the estimated payout component for expense for the (1/2) ROACE Factor as this is redetermined at each reporting period and the expense will fluctuate accordingly.

(3) The remaining performance period matched zero-coupon risk-free interest rate was derived from the U.S. Treasury constant maturities yield curve on the grant date for each respective award, with the exception of the awards granted on February 28, 2019, which used the modification date of May 16, 2019.

(4) The Company utilized its own remaining performance period matched historical volatility in order to develop the expected volatility.

(5) As the (1/2) ROACE Factor is based on performance criteria, the expense fluctuates based on the estimated payout and is redetermined each reporting period and the life-to-date recognized expense for the respective awards is adjusted accordingly.

(6) The combined grant-date fair value per performance share is the combination of the fair value per performance share weighted for the market and performance criteria for the respective awards.

(7) The combined expense per performance share is the combination of the expense per performance share weighted for the market and performance criteria for the respective awards.

Outperformance share award

An outperformance share award was granted during the year ended December 31, 2019, in conjunction with the appointment of the Company's President, and is accounted for as an equity award. The award was adjusted for the Company's 1-for-20 reverse stock split as discussed in Note 8.a. If earned, the payout ranges from 0 to 50,000 shares in the Company's common stock per the vesting schedule. This award is subject to a combination of market and service vesting criteria, therefore, a Monte Carlo simulation prepared by an independent third party was utilized to determine the grant-date fair value with the associated expense recognized over the requisite service period. The payout of this award is based on the highest 50 consecutive trading day average closing stock price of the Company that occurs during the performance period that commenced on June 3, 2019 and ends on June 3, 2022 ("Final Date"). Of the earned outperformance shares, one-third of the award will vest on the Final Date, one-third will vest on the first anniversary of the Final Date and one-third will vest on the second anniversary of the Final Date, provided that the participant has been continuously employed with the Company through the applicable vesting date. Per the award agreement terms, if employment is terminated prior to any vesting date for reasons other than death or disability, then any outperformance shares that have not vested as of such date shall be forfeited and canceled. If the participant's employment is terminated prior to any vesting date by reason of death or disability, and the market criteria is satisfied, then the participant will receive a prorated number of shares based on the number of days the employee was employed with the Company during the performance period.

The total fair value of the outperformance share award and the assumptions used to estimate the fair value of the outperformance share award as of the grant date presented are as follows:

		June 3, 2019
Performance period		3.00 years
Risk-free interest rate(1)		1.77 %
Dividend yield		— %
Expected volatility(2)		55.77 %
Closing stock price on grant date(3)	$	51.8
Total fair value of outperformance share award (in thousands)	$	670

(1) The performance period matched zero-coupon risk-free interest rate was derived from the U.S. Treasury constant maturities yield curve on the grant date.

(2) The Company utilized its own performance period matched historical volatility in order to develop the expected volatility.

(3) Closing stock price on grant date has been retroactively adjusted to reflect the Company's 1-for-20 reverse stock split effective June 1, 2020, as described in Note 8.a.

As of December 31, 2020, unrecognized equity-based compensation related to the outperformance share award expected to vest was $0.4 million. Such cost is expected to be recognized over a weighted-average period of 3.50 years.

Performance unit awards

Performance unit awards, which the Company has determined are liability awards since they are settled in cash, are subject to a combination of market, performance and service vesting criteria. For portions of awards with market criteria, which include: (i) the RTSR Performance Percentage (as defined above) and (ii) the ATSR Appreciation (as defined above), a Monte Carlo simulation prepared by an independent third party is utilized to determine the fair value, and is re-measured at each reporting period until settlement. For portions of awards with performance criteria, which is the ROACE Percentage (as defined above), the Company's closing stock price is utilized to determine the fair value and is re-measured on the last trading day of each reporting period until settlement and, additionally, the associated expense fluctuates based on an estimated payout for the three-year performance period. The expense related to the performance unit awards is recognized on a straight-line basis over the three-year requisite service period of the awards, and the life-to-date recognized expense is adjusted accordingly at each reporting period based on the quarterly fair value re-measurements and redetermination of the estimated payout for the performance criteria. Any units earned, are expected to be paid in cash during the first quarter following the completion of the requisite service period, based on the achievement of certain market and performance criteria, and the payout can range from 0% to 200%, but is capped at 100% if the ATSR Appreciation is zero or less. Per the

award agreement terms, if employment is terminated prior to the restriction lapse date for reasons other than death or disability, the performance unit awards are forfeited and canceled. If the termination of employment is by reason of death or disability, and the market and performance criteria are satisfied, then the holder of the earned performance unit awards will receive a prorated payment based on the number of days the participant was employed with the Company during the performance period.

The following table reflects the performance unit award activity for the year ended December 31, 2020:

(in thousands)	Performance units[1]
Outstanding as of December 31, 2019	—
Granted[2]	123
Forfeited	(24)
Outstanding as of December 31, 2020	99

(1) Units have been retroactively adjusted to reflect the Company's 1-for-20 reverse stock split effective June 1, 2020, as described in Note 8.a.

(2) The amounts potentially payable in cash at the end of the requisite service period for the performance unit awards granted on March 5, 2020 will be determined based on three criteria: (i) RTSR Performance Percentage, (ii) ATSR Appreciation and (iii) ROACE Percentage. The RTSR Performance Percentage, ATSR Appreciation and ROACE Percentage will be used to identify the "RTSR Factor," the "ATSR Factor" and the "ROACE Factor," respectively, which are used to compute the "Performance Multiple" and ultimately to determine the final value of each performance unit to be paid in cash on the payment date per the award agreement, subject to withholding requirements. In computing the Performance Multiple, the RTSR Factor is given a 1/3 weight, the ATSR Factor a 1/3 weight and the ROACE Factor a 1/3 weight. These awards have a performance period of January 1, 2020 to December 31, 2022.

The following table presents (i) the fair values per performance unit and the assumptions used to estimate these fair values per performance unit and (ii) the expense per performance unit, which is the fair value per performance unit adjusted for the estimated payout of the performance criteria, for the outstanding performance unit awards as of December 31, 2020 for the grant date presented:

		March 5, 2020
Market criteria:		
(1/3) RTSR Factor + (1/3) ATSR Factor:		
Fair value assumptions:		
Remaining performance period		2.02 years
Risk-free interest rate[(1)]		0.13 %
Dividend yield		— %
Expected volatility[(2)]		129.04 %
Closing stock price on December 31, 2020	$	19.70
Fair value per performance unit as of December 31, 2020	$	31.36
Expense per performance unit as of December 31, 2020	$	31.36
Performance criteria:		
(1/3) ROACE Factor:		
Fair value assumptions:		
Closing stock price on December 31, 2020	$	19.70
Fair value per performance unit as of December 31, 2020	$	19.70
Estimated payout for expense as of December 31, 2020		100.00 %
Expense per performance unit as of December 31, 2020[(3)]	$	19.70
Combined:		
Fair value per performance unit as of December 31, 2020[(4)]	$	27.47
Expense per performance unit as of December 31, 2020[(5)]	$	27.47

(1) The remaining performance period matched zero-coupon risk-free interest rate was derived from the U.S. Treasury constant maturities yield curve on December 31, 2020.

(2) The Company utilized its own remaining performance period matched historical volatility in order to develop the expected volatility.

(3) As the (1/3) ROACE Factor is based on performance criteria, the expense fluctuates based on the estimated payout and is redetermined each reporting period and the life-to-date recognized expense for the award is adjusted accordingly.

(4) The combined fair value per performance unit is the combination of the fair value per performance unit weighted for the market and performance criteria for the award.

(5) The combined expense per performance unit is the combination of the expense per performance unit weighted for the market and performance criteria for the award.

As of December 31, 2020, unrecognized equity-based compensation related to the performance unit awards expected to vest was $2.0 million. Such cost is expected to be recognized over a weighted-average period of 2.25 years.

Phantom unit awards

Phantom unit awards, which the Company has determined are liability awards, represent the holder's right to receive the cash equivalent of one share of common stock of the Company for each phantom unit as of the applicable vesting date, subject to withholding requirements. Phantom unit awards granted to employees vest 33%, 33% and 34% per year beginning on the first anniversary of the grant date. Per the award agreement terms, if employment is terminated prior to the restriction lapse date for reasons other than death or disability, the phantom unit awards are forfeited and canceled. If the termination of employment is by reason of death or disability, all of the holder's phantom unit awards automatically vest.

The following table reflects the phantom unit award activity for the year ended December 31, 2020:

(in thousands, except for weighted-average fair value)	Phantom units(1)	Fair value as of December 31, 2020 (per unit)(1)
Outstanding as of December 31, 2019	—	$ —
Granted	75	$ 19.70
Outstanding as of December 31, 2020	75	$ 19.70

(1) Units and per unit data have been retroactively adjusted to reflect the Company's 1-for-20 reverse stock split effective June 1, 2020, as described in Note 8.a

The Company utilizes the closing stock price on the last day of each reporting period to determine the fair value of phantom unit awards and the life-to-date recognized expense is adjusted accordingly. As of December 31, 2020, unrecognized equity-based compensation related to the phantom unit awards expected to vest was $1.1 million. Such cost is expected to be recognized over a weighted-average period of 2.25 years.

Equity-based compensation

The following table reflects equity-based compensation expense for the years presented:

	Years ended December 31,		
(in thousands)	2020	2019	2018
Equity awards:			
Restricted stock awards	$ 8,839	$ 13,169	$ 25,271
Performance share awards	2,545	(1,250)	15,192
Outperformance share award	174	101	—
Stock option awards	77	740	3,862
Total share-settled equity-based compensation, gross	$ 11,635	$ 12,760	$ 44,325
Less amounts capitalized	(3,418)	(4,470)	(7,929)
Total share-settled equity-based compensation, net	$ 8,217	$ 8,290	$ 36,396
Liability awards:			
Performance unit awards	$ 749	$ —	$ —
Phantom unit awards	404	—	—
Total cash-settled equity-based compensation, gross	$ 1,153	$ —	$ —
Less amounts capitalized	(163)	—	—
Total cash-settled equity-based compensation, net	$ 990	$ —	$ —
Total equity-based compensation, net	$ 9,207	$ 8,290	$ 36,396

See Note 18 for discussion of the Company's organizational restructurings and the related equity-based compensation reversals during the years ended December 31, 2020 and 2019.

b. 401(k) plan

The Company sponsors a 401(k) plan that is a defined contribution plan for the benefit of all employees at the date of hire. The plan allows eligible employees to make pre-tax and after-tax contributions up to 100% of their annual eligible compensation, not to exceed annual limits established by the federal government. The Company makes matching contributions of up to 6% of an employee's compensation and may make additional discretionary contributions for eligible employees. Employees are 100% vested in the employer contributions upon receipt.

The following table presents the contributions expense recognized for the Company's 401(k) plan for the years presented:

(in thousands)	Years ended December 31, 2020	2019	2018
Contributions	$ 1,649	$ 1,742	$ 2,156

Note 10 Derivatives

The Company has three types of derivative instruments as of December 31, 2020: (i) commodity derivatives, (ii) a debt interest rate derivative and (iii) a contingent consideration derivative. See Notes (i) 2.e for the Company's significant accounting policies for derivatives and presentation in the consolidated financial statements, (ii) 11.a for fair value measurement of derivatives on a recurring basis and (iii) 19.b for derivatives subsequent events.

The following table summarizes the Company's gain on derivatives, net by type of derivative instrument for the periods presented:

(in thousands)	Years ended December 31, 2020	2019	2018
Commodity	$ 73,662	$ 80,351	$ 42,984
Interest rate	(343)	—	—
Contingent consideration	6,795	(1,200)	—
Gain on derivatives, net	$ 80,114	$ 79,151	$ 42,984

a. Commodity

Due to the inherent volatility in oil, NGL and natural gas prices and differences in the prices of oil, NGL and natural gas between where the Company produces and where the Company sells such commodities, the Company engages in commodity derivative transactions, such as puts, swaps, collars and basis swaps to hedge price risk associated with a portion of the Company's anticipated sales volumes. By removing a portion of the price volatility associated with future sales volumes, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flows from operations.

Each put transaction has an established floor price. The Company pays its counterparty a premium, which can be paid at inception or deferred until settlement, to enter into the put transaction. When the settlement price is below the floor price, the counterparty pays the Company an amount equal to the difference between the settlement price and the floor price multiplied by the hedged contract volume. When the settlement price is at or above the floor price in an individual month in the contract period, the put option expires with no settlement for that particular month, except with regard to the deferred premium, if any.

Each swap transaction has an established fixed price. When the settlement price is below the fixed price, the counterparty pays the Company an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, the Company pays its counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

Each collar transaction has an established price floor and ceiling. Depending on the terms, the Company may pay its counterparty a premium, which can be paid at inception or deferred until settlement. When the settlement price is below the price floor established by these collars, the counterparty pays the Company an amount equal to the difference between the settlement price and the price floor multiplied by the hedged contract volume. When the settlement price is above the price ceiling established by these collars, the Company pays its counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the hedged contract volume. When the settlement price is at or between the price floor and price ceiling established by these collars in an individual month in the contract period, the collar expires with no settlement paid by either the Company or the counterparty for that particular month, except with regard to the deferred premium, if any.

Each basis swap transaction has an established fixed basis differential corresponding to two floating index prices. When the settlement basis differential is below the fixed basis differential, the counterparty pays the Company an amount equal to the difference between the fixed basis differential and the settlement basis differential multiplied by the hedged contract volume. When the settlement basis differential is above the fixed basis differential, the Company pays the counterparty an amount equal to the difference between the settlement basis differential and the fixed basis differential multiplied by the hedged contract volume.

During the year ended December 31, 2020, the Company's derivatives were settled based on reported prices on commodity exchanges, with (i) oil derivatives settled based on WTI NYMEX pricing and Brent ICE pricing, (ii) NGL derivatives settled based on Mont Belvieu OPIS pricing and (iii) natural gas derivatives settled based on Henry Hub NYMEX and Waha Inside FERC pricing.

During the year ended December 31, 2020, the Company completed hedge restructurings by (i) early terminating collars and entering into new swaps and (ii) early terminating swaps resulting in proceeds of $6.3 million. The following table details the commodity derivatives that were terminated:

	Aggregate volumes (Bbl)	Weighted-average floor price ($/Bbl)	Weighted-average ceiling price ($/Bbl)	Contract period
WTI NYMEX - Swaps	389,180	$ 60.25	$ 60.25	September 2020 - December 2020
WTI NYMEX - Collars	912,500	$ 45.00	$ 71.00	January 2021 - December 2021

During the year ended December 31, 2019, the Company completed hedge restructurings by early terminating puts and collars and entering into new swaps. The Company paid a net termination amount of $5.4 million that included the full settlement of the deferred premiums associated with a portion of these early-terminated puts and collars. The present value of these deferred premiums, classified under Level 3 of the fair value hierarchy, upon their early termination was $7.2 million. See Note 11 for information about the fair value hierarchy levels. The following table details the commodity derivatives that were terminated:

	Aggregate volumes (Bbl)	Weighted-average floor price ($/Bbl)	Weighted-average ceiling price ($/Bbl)	Contract period
WTI NYMEX - Puts	5,087,500	$ 46.03	$ —	April 2019 - December 2019
WTI NYMEX - Put	366,000	$ 45.00	$ —	January 2020 - December 2020
WTI NYMEX - Collars	1,134,600	$ 45.00	$ 76.13	January 2020 - December 2020

The following table summarizes open commodity derivative positions as of December 31, 2020, for commodity derivatives that were entered into through December 31, 2020, for the settlement periods presented:

	Year 2021	Year 2022
Oil:		
Brent ICE - Puts[1]:		
Volume (Bbl)	2,463,750	—
Weighted-average floor price ($/Bbl)	$ 55.00	$ —
Brent ICE - Swaps:		
Volume (Bbl)	5,037,000	3,759,500
Weighted-average price ($/Bbl)	$ 49.43	$ 47.05
Brent ICE - Collars:		
Volume (Bbl)	584,000	—
Weighted-average floor price ($/Bbl)	$ 45.00	$ —
Weighted-average ceiling price ($/Bbl)	$ 59.50	$ —
Total Brent ICE:		
Total volume with floor (Bbl)	8,084,750	3,759,500
Weighted-average floor price ($/Bbl)	$ 50.80	$ 47.05
Total volume with ceiling (Bbl)	5,621,000	3,759,500
Weighted-average ceiling price ($/Bbl)	$ 50.47	$ 47.05
NGL:		
Mont Belvieu OPIS:		
Purity Ethane - Swaps:		
Volume (Bbl)	912,500	—
Weighted-average price ($/Bbl)	$ 12.01	$ —
Non-TET Propane - Swaps:		
Volume (Bbl)	2,423,235	—
Weighted-average price ($/Bbl)	$ 22.90	$ —
Non-TET Normal Butane - Swaps:		
Volume (Bbl)	807,745	—
Weighted-average price ($/Bbl)	$ 25.87	$ —
Non-TET Isobutane - Swaps:		
Volume (Bbl)	220,460	—
Weighted-average price ($/Bbl)	$ 26.55	$ —
Non-TET Natural Gasoline - Swaps:		
Volume (Bbl)	881,110	—
Weighted-average price ($/Bbl)	$ 38.16	$ —
Total NGL volume (Bbl)	5,245,050	—
Natural gas:		
Henry Hub NYMEX - Swaps:		
Volume (MMBtu)	42,522,500	3,650,000
Weighted-average price ($/MMBtu)	$ 2.59	$ 2.73
Waha Inside FERC to Henry Hub NYMEX - Basis Swaps:		
Volume (MMBtu)	48,508,500	7,300,000
Weighted-average differential ($/MMBtu)	$ (0.51)	$ (0.53)

(1) Associated with these open positions were $50.6 million of premiums, which were paid at the respective contracts' inception during the year ended December 31, 2020.

b. Interest rate

Due to the inherent volatility in interest rates, the Company has entered into an interest rate derivative swap to hedge interest rate risk associated with a portion of the Company's anticipated outstanding debt under the Senior Secured Credit Facility. The Company will pay a fixed rate over the contract term for that portion. By removing a portion of the interest rate volatility associated with anticipated outstanding debt, the Company expects to mitigate, but not eliminate, the potential effects of variability in cash flows from operations.

The following table presents the interest rate derivative that was entered into during the year ended December 31, 2020:

	Notional amount (in thousands)	Fixed rate	Contract period
LIBOR - Swap	$ 100,000	0.345 %	April 16, 2020 - April 18, 2022

c. Contingent consideration

The Company's acquisition of oil and natural gas properties that closed on April 30, 2020 provides for potential contingent payments to be paid by the Company if the arithmetic average of the monthly settlement WTI NYMEX prices exceed certain thresholds for the contingency period beginning on January 1, 2021 and ending on the earlier of December 31, 2022 or the date the counterparty has received the maximum consideration of $1.2 million.

The Company's acquisition of oil and natural gas properties that closed on December 12, 2019 provided for a potential contingent payment. If the arithmetic average of the monthly settlement WTI NYMEX prices exceeded a certain threshold for the contingency period beginning January 1, 2020 through December 31, 2020, the Company would have been required to pay to the counterparty an amount equal to $20 million. As the provisions for this contingent payment were not met, no payment by the Company was required.

See Notes 4.a and 4.c for further discussion of the Company's acquisitions associated with potential contingent consideration payments. At each quarterly reporting period, the Company remeasures contingent considerations with the change in fair values recognized in earnings.

Note 11 Fair value measurements

The Company has categorized its assets and liabilities measured at fair value, based on the priority of inputs to the valuation techniques, into a three-level fair value hierarchy. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3).

Assets and liabilities recorded at fair value on the consolidated balance sheets are categorized based on inputs to the valuation techniques as follows:

Level 1— Assets and liabilities recorded at fair value for which values are based on unadjusted quoted prices for identical assets or liabilities in an active market that management has the ability to access. Active markets are considered to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2— Assets and liabilities recorded at fair value for which values are based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the assets or liabilities. Substantially all of these inputs are observable in the marketplace throughout the full term of the price risk management instrument and can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace.

Level 3— Assets and liabilities recorded at fair value for which values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. Unobservable inputs are not corroborated by market data. These inputs reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability.

a. Fair value measurement on a recurring basis

For further discussion of the Company's derivatives, see Notes (i) 2.e for the Company's significant accounting policies for derivatives, (ii) 10 for derivatives and (iii) 19.b for derivatives subsequent events.

Balance sheet presentation

The following tables present the Company's derivatives' three-level fair value hierarchy by (i) assets and liabilities, (ii) current and noncurrent, (iii) commodity, interest rate and contingent consideration derivatives and (iv) oil, NGL, natural gas, LIBOR and/or deferred premiums, and provide a total, on a gross basis and a net basis reflected in "Derivatives" on the consolidated balance sheets as of the dates presented:

	December 31, 2020					
(in thousands)	Level 1	Level 2	Level 3	Total gross fair value	Amounts offset	Net fair value presented on the consolidated balance sheets
Assets:						
Current:						
Commodity - Oil	$ —	$ 32,958	$ —	$ 32,958	$ (24,930)	$ 8,028
Commodity - NGL	—	2,720	—	2,720	(2,720)	—
Commodity - Natural gas	—	521	—	521	(656)	(135)
Commodity - Oil deferred premiums	—	—	—	—	—	—
Noncurrent:						
Commodity - Oil	$ —	$ —	$ —	$ —	$ —	$ —
Commodity - NGL	—	—	—	—	—	—
Commodity - Natural gas	—	535	—	535	(535)	—
Liabilities:						
Current:						
Commodity - Oil	$ —	$ (25,118)	$ —	$ (25,118)	$ 24,930	$ (188)
Commodity - NGL	—	(16,185)	—	(16,185)	2,720	(13,465)
Commodity - Natural gas	—	(17,958)	—	(17,958)	656	(17,302)
Commodity - Oil deferred premiums	—	—	—	—	—	—
Interest rate - LIBOR	—	(206)	—	(206)	—	(206)
Contingent consideration	—	(665)	—	(665)	—	(665)
Noncurrent:						
Commodity - Oil	$ —	$ (10,932)	$ —	$ (10,932)	$ —	$ (10,932)
Commodity - NGL	—	—	—	—	—	—
Commodity - Natural gas	—	(1,476)	—	(1,476)	535	(941)
Interest rate - LIBOR	—	(63)	—	(63)	—	(63)
Contingent consideration	—	(115)	—	(115)	—	(115)
Net derivative liability positions	$ —	$ (35,984)	$ —	$ (35,984)	$ —	$ (35,984)

	December 31, 2019					
(in thousands)	Level 1	Level 2	Level 3	Total gross fair value	Amounts offset	Net fair value presented on the consolidated balance sheets
Assets:						
Current:						
Commodity - Oil	$ —	$ 11,723	$ —	$ 11,723	$ (5,301)	$ 6,422
Commodity - NGL	—	13,787	—	13,787	(1,297)	12,490
Commodity - Natural gas	—	33,494	—	33,494	—	33,494
Commodity - Oil deferred premiums	—	—	—	—	(477)	(477)
Noncurrent:						
Commodity - Oil	$ —	$ 1,577	$ —	$ 1,577	$ —	$ 1,577
Commodity - NGL	—	9,547	—	9,547	—	9,547
Commodity - Natural gas	—	12,263	—	12,263	—	12,263
Liabilities:						
Current:						
Commodity - Oil	$ —	$ (5,649)	$ —	$ (5,649)	$ 5,301	$ (348)
Commodity - NGL	—	(1,297)	—	(1,297)	1,297	—
Commodity - Natural gas	—	—	—	—	—	—
Commodity - Oil deferred premiums	—	—	(477)	(477)	477	—
Interest rate - LIBOR $—	—	—	—	—	—	—
Contingent consideration	—	(7,350)	—	(7,350)	—	(7,350)
Noncurrent:						
Commodity - Oil	$ —	$ —	$ —	$ —	$ —	$ —
Commodity - NGL	—	—	—	—	—	—
Commodity - Natural gas	—	—	—	—	—	—
Interest rate - LIBOR	—	—	—	—	—	—
Contingent consideration	—	—	—	—	—	—
Net derivative asset (liability) positions	$ —	$ 68,095	$ (477)	$ 67,618	$ —	$ 67,618

Commodity

Significant Level 2 inputs associated with the calculation of discounted cash flows used in the fair value mark-to-market analysis of commodity derivatives include each commodity derivative contract's corresponding commodity index price(s), forward price curve models for substantially similar instruments and counterparty risk-adjusted discount rates generated from a compilation of data gathered by a third-party valuation specialist. The Company reviewed the third party specialist's valuations of commodity derivatives, including the related inputs, and analyzed changes in fair values between reporting dates.

The Company's deferred premiums associated with its commodity derivative contracts are categorized as Level 3, as the Company utilized a net present value calculation to determine the valuation. They are considered to be measured on a recurring basis as the commodity derivative contracts they derive from are measured on a recurring basis. As commodity derivative contracts containing deferred premiums were entered into, the Company discounted the associated deferred premium to its net present value at the contract trade date, using the Senior Secured Credit Facility rate at the trade date (input rate), and then recorded the change in net present value to interest expense over the period from trade until the final settlement date at the end of the contract. After this initial valuation, the input rate of each deferred premium was not adjusted; therefore, significant increases (decreases) in the Senior Secured Credit Facility rate would have resulted in a significantly lower (higher) fair value measurement for each new contract entered into that contained a deferred premium; however, the initial valuation for the deferred premiums already recorded would have remained unaffected. While the Company believes the sources utilized to arrive at the fair value estimates are reliable, different sources or methods could have yielded different fair value estimates. The Company's deferred premiums have settled as of December 31, 2020.

The following table summarizes the changes in net assets and liabilities classified as Level 3 measurements for the periods presented:

(in thousands)	Years ended December 31, 2020	2019	2018
Balance of Level 3 at beginning of year	$ (477)	$ (16,565)	$ (28,683)
Change in net present value of commodity derivative deferred premiums(1)	—	(139)	(694)
Purchases of commodity derivative deferred premiums	—	—	(7,523)
Settlements of commodity derivative deferred premiums(2)	477	16,227	20,335
Balance of Level 3 at end of year	$ —	$ (477)	$ (16,565)

(1) These amounts are included in "Interest expense" on the consolidated statements of operations.

(2) The amount for the year ended December 31, 2019 includes $7.2 million that represents the present value of deferred premiums settled upon their early termination.

Interest rate

Significant Level 2 inputs associated with the calculation of discounted cash flows used in the fair value mark-to-market analysis of the interest rate derivative include the LIBOR interest rate forward curve and a counterparty risk-adjusted discount rate generated from a compilation of data gathered by a third-party valuation specialist. The Company reviewed the third-party specialist's valuation of the interest rate derivative, including the related inputs, and analyzed changes in fair values between reporting dates.

Contingent consideration

Significant Level 2 inputs for the option pricing model used in the fair value mark-to-market analysis of the contingent considerations include WTI NYMEX Futures price curves, implied volatility of futures contracts and the Company's credit risk-adjusted discount rate generated from a compilation of data gathered by a third-party valuation specialist. The Company reviewed the third-party specialist's valuations, including the related inputs, and analyzed changes in fair values between the acquisition closing dates and the reporting dates. The fair values of the contingent considerations were recorded as part of the basis in the oil and natural gas properties acquired and as a contingent consideration derivative liability. At each quarterly reporting period prior to the end of the contingency period, the Company will remeasure the contingent consideration with the changes in fair value recognized in earnings.

The Company's acquisition of oil and natural gas properties that closed on April 30, 2020 provides for potential contingent payments to be paid by the Company. The fair value of the contingent consideration derivative liability was $0.2 million as of the April 30, 2020 acquisition date, and $0.8 million as of December 31, 2020.

The Company's acquisition of oil and natural gas properties that closed on December 12, 2019 provided for a potential contingent payment to be paid by the Company. The fair value of the contingent consideration derivative liability was $6.2 million as of the December 12, 2019 acquisition date. As the provisions for this contingent payment were not met, no payment by the Company was required.

See Notes 4.a and 4.c for further discussion of the Company's acquisitions associated with the potential contingent consideration payments.

b. Fair value measurement on a nonrecurring basis

See Note 2.i for the Level 2 fair value hierarchy input assumptions used in estimating the NRV of inventory used to determine the $1.4 million impairment expense of inventory recorded during the year ended December 31, 2020, pertaining to line-fill and other inventories. The Company recorded $0.3 million in impairment expense of inventory during the year ended December 31, 2019, pertaining to line-fill. There were no impairments of inventory recorded during the year ended December 31, 2018.

See Note 4.c for the Level 3 fair value hierarchy input assumptions used in estimating the fair values of assets acquired and liabilities assumed for the acquisition of oil and natural gas properties accounted for as a business combination during the

year ended December 31, 2019. There were no acquisitions accounted for as business combinations during the years ended December 31, 2020 or 2018.

Impairments are recorded on long-lived assets when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying amount. Impairment is measured based on the excess of the carrying amount over the fair value of the asset. For purposes of fair value measurement, it was determined that the impairment of long-lived assets is classified as Level 3, based on the use of internally developed cash flow models. The Company recorded $8.2 million in impairment expense of long-lived assets during the year ended December 31, 2020, pertaining to midstream service assets. There were no long-lived asset impairments recorded during the years ended December 31, 2019 or 2018.

c. Items not accounted for at fair value

The carrying amounts reported on the consolidated balance sheets for cash and cash equivalents, accounts receivable, accounts payable, accrued capital expenditures, undistributed revenue and royalties and other accrued assets and liabilities approximate their fair values.

The Company has not elected to account for its debt instruments at fair value. The following table presents the carrying amounts and fair values of the Company's debt as of the dates presented:

	December 31, 2020		December 31, 2019	
(in thousands)	Long-term debt	Fair value[(1)]	Long-term debt	Fair value[(1)]
January 2022 Notes	$ —	$ —	$ 450,000	$ 439,875
March 2023 Notes	—	—	350,000	332,500
January 2025 Notes	577,913	499,299	—	—
January 2028 Notes	361,044	299,667	—	—
Senior Secured Credit Facility	255,000	255,187	375,000	375,275
Total	$ 1,193,957	$ 1,054,153	$ 1,175,000	$ 1,147,650

(1) The fair values of the outstanding debt on the notes were determined using the Level 1 fair value hierarchy quoted market prices for each respective instrument as of December 31, 2020 and 2019. The fair values of the outstanding debt on the Senior Secured Credit Facility were estimated utilizing the Level 2 fair value hierarchy pricing model for similar instruments as of December 31, 2020 and 2019.

Note 12 Net income (loss) per common share

Basic net income (loss) per common share is computed by dividing net income (loss) by the weighted-average common shares outstanding for the period. Diluted net income (loss) per common share reflects the potential dilution of non-vested restricted stock awards, outstanding stock option awards, non-vested performance share awards and the non-vested outperformance share award. See Note 9.a for additional discussion of these awards. For the years ended December 31, 2020 and 2019, all of these awards were anti-dilutive due to the Company's net loss and, therefore, were excluded from the calculation of diluted net loss per common share. The dilutive effects of these awards were calculated utilizing the treasury stock method for the year ended December 31, 2018.

The following table reflects the calculations of basic and diluted (i) weighted-average common shares outstanding and (ii) net income (loss) per common share for the periods presented:

	Years ended December 31,		
(in thousands, except for per share data)	2020	2019	2018
Net income (loss) (numerator)	$ (874,173)	$ (342,459)	$ 324,595
Weighted-average common shares outstanding (denominator)(1)(2):			
Basic	11,668	11,565	11,617
Dilutive non-vested restricted stock awards	—	—	41
Dilutive outstanding stock option awards	—	—	1
Diluted	11,668	11,565	11,659
Net income (loss) per common share(1):			
Basic	$ (74.92)	$ (29.61)	$ 27.94
Diluted	$ (74.92)	$ (29.61)	$ 27.84

(1) Shares and per share data have been retroactively adjusted to reflect the Company's 1-for-20 reverse stock split effective June 1, 2020, as described in Note 8.a.

(2) Weighted-average common shares outstanding used in the computation of basic and diluted net income (loss) per common share was computed taking into account share repurchases that occurred during the year ended December 31, 2018. See Note 8.b for additional discussion of the Company's share repurchase program.

Note 13 Income taxes

The Company is subject to federal and state income taxes and the Texas franchise tax. The following table presents the federal and state income taxes included in "Current" and "Deferred" income tax benefit (expense) in the consolidated statements of operations for the periods presented:

	Years ended December 31,		
(in thousands)	2020	2019	2018
Current income tax benefit (expense):			
Federal	$ —	$ —	$ —
State	—	—	807
Deferred income tax benefit (expense):			
Federal	—	—	—
State	3,946	2,588	(5,056)
Total income tax benefit (expense)	$ 3,946	$ 2,588	$ (4,249)

The deferred income tax benefit (expense) affects the Texas net deferred tax asset (liability). See below for the table of significant components of the Company's Texas net deferred tax asset (liability) as of December 31, 2020 and 2019.

A current tax refund of $0.8 million of Texas franchise tax was received as a result of differences in estimated versus actual taxable income and was recorded as a current income tax benefit for the year ended December 31, 2018.

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"). With the passage of the Tax Act, the Alternative Minimum Tax ("AMT") on corporations was repealed and a provision was added allowing corporations to offset future tax liabilities by the amount of AMT paid with an AMT credit carryforward. The Coronavirus Aid, Relief, and Economic Security Act, enacted March 27, 2020 ("CARES Act"), modified the opportunity for corporations to receive the AMT carryover refunds by adding in a provision where the AMT credit carryforwards do not expire and are fully refundable with the filing of the Company's 2019 consolidated tax return. The Company paid AMT during the year ended December 31, 2017, creating an AMT credit carryforward in the amount of $4.1 million, of which $2.0 million was received during the year ended December 31, 2019 and the remaining $2.1 million was received during the year ended December 31, 2020.

Total income tax benefit (expense) differed from amounts computed by applying the applicable federal income tax rate of 21% for the years ended December 31, 2020, 2019 and 2018 to pre-tax earnings as a result of the following:

(in thousands)	Years ended December 31, 2020	2019	2018
Income tax benefit (expense) computed by applying the statutory rate	$ 184,405	$ 72,460	$ (69,057)
(Increase) decrease in deferred tax valuation allowance	(182,634)	(69,316)	74,289
State income tax and change in valuation allowance	2,903	1,863	(9,070)
Other items	(728)	(2,419)	(411)
Total income tax benefit (expense)	$ 3,946	$ 2,588	$ (4,249)

The effective tax rate was not meaningful for the periods presented. The Company's effective tax rate is affected by changes in tax rates, valuation allowances, recurring permanent differences and by discrete items that may occur in any given year, but are not consistent from year to year.

The Company is required to estimate the federal and state income taxes in each of the jurisdictions it operates in. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items for tax and financial accounting purposes. These differences and the Company's net operating loss carryforwards result in deferred tax assets and liabilities.

The following table presents significant components of the Company's Texas net deferred tax asset (liability) as of the dates presented:

(in thousands)	December 31, 2020	December 31, 2019
Net operating loss carryforward	$ 444,031	$ 410,697
Oil and natural gas properties, midstream service assets and other fixed assets	22,231	(109,931)
Equity-based compensation	22,494	20,448
Derivatives	7,166	(14,543)
Loss on sale of assets	(8,458)	(7,773)
Other	3,130	5,186
Net deferred tax asset before valuation allowance	490,594	304,084
Valuation allowance	(489,116)	(306,552)
Texas net deferred tax asset (liability)[(1)]	$ 1,478	$ (2,468)

(1) The Texas net deferred tax asset (liability) is included in "Other noncurrent assets, net" and "Other noncurrent liabilities" as of December 31, 2020 and 2019, respectively.

The following table presents the Company's federal net operating loss carryforwards and their applicable expiration dates as of the date presented:

(in thousands)	December 31, 2020
2026	$ 2,741
2027	38,651
2028	228,661
2029	101,932
2030	80,963
Thereafter	1,284,150
Total expiring federal net operating loss carryforwards	1,737,098
Non-expiring federal net operating loss carryforwards	369,536
Total federal net operating loss carryforwards	$ 2,106,634

The Company had federal net operating loss carryforwards totaling $2.1 billion and state of Oklahoma net operating loss carryforwards totaling $34.6 million as of December 31, 2020, which begin expiring in 2026 and 2032, respectively. Due to the passing of the Tax Act, $369.5 million of the federal net operating loss carryforwards will not expire but may be limited in future periods.

A valuation allowance is established to reduce deferred tax assets if it is determined that it is more likely than not that the related tax benefit will not be realized. On a quarterly basis, management evaluates the need for and adequacy of valuation allowances based on the expected realizability of the deferred tax assets and adjusts the amount of such allowances, if necessary. To the extent a valuation allowance is established or is increased or decreased during a period, there is a corresponding expense or reduction of expense within the tax provision in the consolidated statement of operations.

During the years ended December 31, 2020 and 2019, in evaluating whether it was more likely than not that the Company's net deferred tax assets were realizable through future net income, the Company considered all available positive and negative evidence, including (i) its earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition, (ii) its ability to recover net operating loss carryforward deferred tax assets in future years, (iii) the existence of significant proved oil, NGL and natural gas reserves, (iv) its ability to use tax planning strategies, such as electing to capitalize intangible drilling costs as opposed to expensing such costs in order to prevent an operating loss carryforward from expiring unused and future projections of Oklahoma sourced income, (v) its current price protection utilizing oil, NGL and natural gas hedges, (vi) future revenue and operating cost projections that indicate it will produce more than enough taxable income to realize the deferred tax asset based on existing sales prices and cost structures and (vii) current market prices for oil, NGL and natural gas. Based on all the evidence available, the Company determined it was more likely than not that the net deferred tax assets were not realizable. As of December 31, 2020, a total valuation allowance of $489.1 million has been recorded to offset the Company's federal and Oklahoma net deferred tax assets resulting in a Texas net deferred tax asset of $1.5 million that is included in "Other noncurrent assets, net" on the consolidated balance sheets.

The Company files a single return. The Company's income tax returns for the years 2017 through 2020 remain open and subject to examination by federal tax authorities and/or the tax authorities in Oklahoma and Texas, which are the jurisdictions where the Company has operations. Additionally, the statute of limitations for examination of federal net operating loss carryforwards typically does not begin to run until the year the attribute is utilized in a tax return. See Note 2.q for the Company's significant accounting policies for income taxes.

Note 14 Revenue recognition

See Note 2.n for a summary of significant revenue recognition accounting policies. Additional discussion of the underlying contracts that give rise to the Company's revenue and method of recognition is included below.

See Note 5.a in the 2018 Annual Report for discussion of the deferred gain that was recognized as an adjustment to the 2018 beginning balance of accumulated deficit, presented in the consolidated statements of stockholders' equity, in accordance with the modified retrospective approach of adoption of ASC 606.

Oil sales and sales of purchased oil

Under its oil sales contracts, the Company sells produced or purchased oil at the delivery point specified in the contract and collects an agreed-upon index price, net of pricing differentials. The delivery point may be at the wellhead, the inlet of the purchaser's pipeline or nominated pipeline or the Company's truck unloading facility. At the delivery point, the purchaser typically takes custody, title and risk of loss of the product and, therefore, control as defined under ASC 606 typically passes at the delivery point. The Company recognizes revenue at the net price received when control transfers to the purchaser.

The Company engages in transactions in which it sells oil at the lease and subsequently repurchases the same volume of oil from that customer at a downstream delivery point under a separate agreement ("Repurchase Agreement") for use in the sale to the final customer. The commercial reasoning for such transactions may vary. Where a Repurchase Agreement exists, the Company must evaluate whether the customer obtains control of the oil at the lease and therefore whether it is appropriate to recognize revenue for the lease sale. Where the Company has an obligation or a right to repurchase the oil, the customer does not obtain control of the oil because it is limited in its ability to direct the use of, and obtain substantially all of the remaining benefits from the oil even though it may have physical possession of the oil. If the Company repurchases the oil for less than the original selling price, such a transaction will be classified as a lease. If the Company repurchases the oil for equal to or more than the original selling price, then the transaction represents a financing arrangement unless there is only a short passage of time between the sale and repurchase, in which case any excess amount paid represents an expense associated with the sale of oil to the final customer. The Company recognizes such repurchase expense and any transportation expenses incurred for the delivery of the oil to the final customer in the "Transportation and marketing expenses" line item in the accompanying consolidated statements of operations.

Under certain of its customer contracts, the Company is subject to contractual penalties if it fails to deliver contractual minimum volumes to its customers. Such amounts are recorded as a reduction to the transaction price as these amounts do not represent payments to the customer for distinct goods or services and instead relate specifically to the failure to perform under the specific customer contract. Such amounts are recorded as a reduction to the transaction price when payment is determined as probable, typically when such a deficiency occurs.

NGL and natural gas sales

Under its natural gas processing contracts, the Company delivers produced natural gas to a midstream processing entity at the wellhead or the inlet of the processing entity's system. The processing entity processes the natural gas, sells the resulting NGL and residue gas to third parties and pays the Company for the NGL and residue gas with deductions that may include gathering, compression, processing and transportation fees. In these scenarios, the Company evaluates whether it is the principal or the agent in the transaction. For existing contracts, the Company has concluded that it is the agent in the ultimate sale to the third party and the midstream processing entity is the principal and that the Company has transferred control of unprocessed natural gas to the midstream processing entity; therefore, the Company recognizes revenue based on the net amount of the proceeds received from the midstream processing entity who represents the Company's customer. If for future contracts the Company was to conclude that it was the principal with the ultimate third party being the customer, the Company would recognize revenue for those contracts on a gross basis, with gathering, compression, processing, and transportation fees presented as an expense.

Midstream service revenues

Revenue from oil throughput agreements is recognized based on a rate per barrel for volumes transported. Under the Company's oil throughput agreements, a volumetric deduction is taken from customer oil as a pipeline loss allowance. While these amounts represent non-cash consideration under ASC 606, such deductions are immaterial. Revenue from natural gas throughput agreements is recognized based on a rate per MMbtu for volumes transported. Revenue from water delivery, recycling and takeaway is recognized based on the volumes of water for which the services are provided at the applicable contractual rate.

Imbalances

The Company recognizes revenue for all oil, NGL and natural gas sold to purchasers regardless of whether the sales are proportionate to the Company's ownership interest in the property. Production imbalances are recognized as a liability to the extent an imbalance on a specific property exceeds the Company's share of remaining proved oil, NGL and natural gas reserves. The Company is also subject to natural gas pipeline imbalances, which are recorded as accounts receivable or payable at values consistent with contractual arrangements with the owner of the pipeline. The Company did not have any producer or pipeline imbalance positions as of December 31, 2020 or 2019.

Significant judgments

The Company engages in various types of transactions in which unaffiliated midstream entities process the Company's liquids-rich natural gas and, in some scenarios, subsequently market resulting NGL and residue gas to third-party customers on the Company's behalf. These types of transactions require judgment to determine whether the Company is the principal or the agent in the contract and, as a result, whether revenues are recorded gross or net. For existing contracts, the Company has determined that it serves as the agent in the sale of products under certain natural gas processing and marketing agreements with unaffiliated midstream entities in accordance with the control model in ASC 606. As a result, the Company presents revenue on a net basis for amounts expected to be received from third-party customers through the marketing process, with expenses and deductions incurred subsequent to control of the product(s) transferring to the unaffiliated midstream entity being netted against revenue.

Transaction price allocated to remaining performance obligations

A significant number of the Company's product sales are short-term in nature with a contract term of one year or less. For those contracts, the Company has utilized the practical expedient in ASC 606-10-50-14 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 the Company's product sales that have a contract term greater than one year and for its Midstream Services, the Company has utilized the practical expedient in ASC 606-10-50-14A that states that it is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under the Company's product sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied. Under the Midstream Services contracts each unit of service represents a separate performance obligation and therefore performance obligations in respect of future services are wholly unsatisfied.

Contract balances

Under the Company's customer contracts, invoicing occurs once the Company's performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's contracts do not give rise to contract assets or liabilities under ASC 606.

Prior-period performance obligations

For sales of oil, NGL, natural gas and purchased oil, the Company records revenue in the month production is delivered to the purchaser. However, settlement statements and payment may not 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 Company records the differences between estimates and the actual amounts received for product sales once payment is received from the purchaser. Such differences have historically not been significant. The Company uses knowledge of its properties, its properties' historical performance, spot market prices and other factors as the basis for these estimates. For the years ended December 31, 2020, 2019 and 2018, revenue recognized related to performance obligations satisfied in prior reporting periods was not material.

Note 15 Credit risk

Financial instruments that potentially subject the Company to a concentration of credit risk consist of cash and cash equivalents, accounts receivable and derivatives. The Company places its cash and cash equivalents with high credit quality financial institutions. The Company uses commodity and interest rate derivatives to hedge its exposure to commodity prices and interest rate volatility, respectively. These transactions expose the Company to potential credit risk from its counterparties. The Company has entered into International Swaps and Derivatives Association Master Agreements ("ISDA Agreements") with each of its commodity and interest rate derivative counterparties, each of whom is also a lender in its Senior Secured Credit Facility, which, together with hedge agreements with lenders under such facility, is secured by its oil, NGL and natural gas reserves; therefore, the Company is not required to post any additional collateral. The Company did not require collateral from its commodity and interest rate derivative counterparties. The terms of the ISDA Agreements provide the non-defaulting or non-affected party the right to terminate the agreement upon the occurrence of certain events of default and termination events by a party and also provide for the marking to market of outstanding positions and the offset of the mark to market amounts owed to and by the parties (and in certain cases, the affiliates of the non-defaulting or non-affected party) upon termination; therefore, the credit risk associated with its commodity and interest rate derivative counterparties is somewhat mitigated. The Company minimizes the credit risk in commodity and interest rate derivatives by: (i) limiting its exposure to any single counterparty, (ii) entering into commodity and interest rate derivatives only with counterparties that meet its minimum credit quality standard or have a guarantee from an affiliate that meets its minimum credit quality standard and (iii) monitoring the creditworthiness of its counterparties on an ongoing basis. As of December 31, 2020, the Company had a net liability of $35.2 million from the fair values of its open commodity and interest rate derivative contracts. See "Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk" located elsewhere in this Annual Report and Notes 2.e, 10, 11.a and 19.b for additional information regarding the Company's derivatives.

The Company typically sells production to a relatively limited number of customers, as is customary in the exploration, development and production business. The Company's sales of purchased oil are generally made to a few customers. The Company's joint operations accounts receivable are from a number of oil and natural gas companies, partnerships, individuals and others who own interests in the oil and natural gas properties operated by the Company.

The majority of the Company's accounts receivable are unsecured. On occasion the Company requires its customers to post collateral, and the inability or failure of the Company's significant customers to meet their obligations to the Company or their insolvency or liquidation may adversely affect the Company's financial results. In the current market environment, the Company believes that it could sell its production to numerous companies, so that the loss of any one of its major purchasers would not have a material adverse effect on its financial condition and results of operations solely by reason of such loss. Additionally, management believes that any credit risk imposed by a concentration in the oil and natural gas industry is offset by the creditworthiness of the Company's customer base and industry partners. The Company routinely assesses the recoverability of all material trade and other receivables to determine collectability. See Notes 2.d and 14 for additional information regarding the Company's accounts receivable and revenue recognition, respectively.

The following table presents purchasers that individually accounted for 10% or more of the Company's oil, NGL and natural gas sales in at least one of the years presented:

	Years ended December 31,		
	2020	2019	2018
Purchaser A(1)	33 %	59 %	30 %
Purchaser B	24 %	18 %	24 %
Purchaser C(1)	14 %	n/a(2)	n/a(2)
Purchaser D(1)	10 %	n/a(2)	n/a(2)
Purchaser E	n/a(2)	15 %	16 %
Purchaser F	n/a(2)	n/a(2)	16 %

(1) This purchaser of the Company's oil, NGL and natural gas sales is also a purchaser of the Company's sales of purchased oil included in the table below.

(2) This purchaser did not account for 10% or greater of the Company's oil, NGL and natural gas sales.

The following table presents purchasers that individually accounted for 10% or more of the Company's sales of purchased oil in at least one of the years presented:

	Years ended December 31,		
	2020	2019	2018
Purchaser A(1)	69 %	26 %	n/a(2)
Purchaser B	16 %	70 %	64 %
Purchaser C(1)	14 %	n/a(2)	n/a(2)
Purchaser D(1)	n/a(2)	n/a(2)	36 %

(1) This purchaser of the Company's sales of purchased oil is also a purchaser of the Company's oil, NGL and natural gas sales included in the table above.

(2) This purchaser did not account for 10% or greater of the Company's sales of purchased oil.

Note 16 Commitments and contingencies

a. Litigation

From time to time, the Company is subject to various legal proceedings arising in the ordinary course of business, including proceedings for which the Company may not have insurance coverage. While many of these matters involve inherent uncertainty, as of the date hereof, the Company does not currently believe that any such legal proceedings will have a material adverse effect on the Company's business, financial position, results of operations or liquidity. During the year ended December 31, 2019, the Company finalized and received a favorable settlement of $42.5 million in connection with the Company's damage claims asserted in a previously disclosed litigation matter relating to a breach and wrongful termination of a crude oil purchase agreement. This settlement is recorded as "Litigation settlement" on the consolidated statement of operations. The Company does not anticipate receiving further payments in connection with this matter as this settlement constituted a full and final satisfaction of the Company's claims.

b. Drilling rig contract

The Company enters into drilling rig contracts to ensure availability of desired rigs to facilitate drilling plans. The Company has an operating lease for a term of multiple months and contains an early termination clause that requires the Company to potentially pay penalties to the third party should the Company cease drilling efforts. These penalties would negatively impact the Company's financial statements upon early contract termination. There were no penalties incurred for early contract termination for the years ended December 31, 2020, 2019 or 2018. As the contract is an operating lease with an initial term greater than 12 months, the present value of the future commitment as of December 31, 2020 is included in current and noncurrent "Operating lease liabilities" on the consolidated balance sheet as of December 31, 2020. See Note 5 for further discussion of leases.

c. Firm sale and transportation commitments

The Company has committed to deliver, for sale or transportation, fixed volumes of product under certain contractual arrangements that specify the delivery of a fixed and determinable quantity. If not fulfilled, the Company is subject to firm transportation payments on excess pipeline capacity and other contractual penalties. These commitments are normal and customary for the Company's business. In certain instances, the Company has used spot market purchases to meet its commitments in certain locations or due to favorable pricing. A portion of the Company's commitments is related to transportation commitments with a certain pipeline pertaining to the gathering of the Company's production from established acreage that extends into 2024. The Company was unable to satisfy a portion of this particular commitment with produced or purchased oil, therefore, the Company expensed firm transportation payments on excess capacity of $4.0 million during the year ended December 31, 2020, which is recorded in "Transportation and marketing expenses" on the consolidated statement of operations. The Company's estimated aggregate liability of firm transportation payments on excess capacity is $3.5 million as of December 31, 2020, and is included in "Accounts payable and accrued liabilities" on the consolidated balance sheet. The Company expensed other contractual penalties related to sales commitments of $0.9 million and $4.7 million during the years ended December 31, 2019 and 2018, respectively, which is recorded net with oil, NGL, and natural gas sales revenues on the consolidated statements of operations. As of December 31, 2020, future firm sale and transportation commitments of $274.5 million are expected to be satisfied, and as such, are not recorded as a liability on the consolidated balance sheet.

d. Sand commitment

During the year ended December 31, 2020, the Company entered into an agreement to take delivery of processed sand at a fixed price for one year, which is utilized in the Company's completions activities, from its sand mine that is operated by a third-party contractor. As of December 31, 2020, under the terms of this agreement, the Company is required to purchase a certain volume remaining under its commitment or it would incur a shortfall payment of $4.7 million at the end of the contract period.

e. Federal and state regulations

Oil and natural gas exploration, production and related operations are subject to extensive federal and state laws, rules and regulations. Failure to comply with these laws, rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases the cost of doing business and affects profitability. The Company believes that it is in compliance with currently applicable federal and state regulations related to oil and natural gas exploration and production, and that compliance with the current regulations will not have a material adverse impact on the financial position or results of operations of the Company. These rules and regulations are frequently amended or reinterpreted; therefore, the Company is unable to predict the future cost or impact of complying with these regulations.

f. Environmental

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, among other things, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed in the period incurred. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. Management believes no materially significant liabilities of this nature existed as of December 31, 2020 or 2019.

Note 17 Related parties

a. Helmerich & Payne, Inc.

The former Chairman of the Company's board of directors, whose term on the Company's board of directors ended on May 14, 2020, was on the board of directors of Helmerich & Payne, Inc. ("H&P").

The following table presents the operating lease liabilities related to H&P included in the consolidated balance sheet as of the date presented:

(in thousands)	December 31, 2019
Operating lease liabilities:	
Current	$ 9,605
Noncurrent	6,907
Total operating lease liabilities(1)	$ 16,512

(1) As of December 31, 2019, the Company had two drilling rig contracts with H&P that were accounted for as long-term operating leases due to the initial term being greater than 12 months, and was capitalized and included in "Operating lease right-of-use-assets" on the consolidated balance sheet. The present value of the future commitment was included in current and noncurrent operating lease liabilities on the consolidated balance sheet. See Note 5 for additional discussion of the Company's significant accounting policies on leases.

The following table presents the capital expenditures for oil and natural gas properties paid to H&P included in the consolidated statements of cash flows for the periods presented:

	Years ended December 31,		
(in thousands)	2020	2019	2018
Capital expenditures for oil and natural gas properties(1)	$ 18,104	$ 18,089	$ 3,040

(1) Amount reflected for the year ended December 31, 2020 is through the date of the former Chairman's expiration of term on the Company's board of directors on May 14, 2020.

b. Halliburton

Beginning in 2020, the Chairman of the Company's board of directors is on the board of directors of Halliburton Company ("Halliburton"). Halliburton provides drilling and completions services to the Company.

The following table presents the capital expenditures for oil and natural gas properties paid to Halliburton included in the consolidated statement of cash flows for the period presented:

(in thousands)	Year ended December 31, 2020
Capital expenditures for oil and natural gas properties	$ 63,886

Note 18 Organizational restructurings

On June 17, 2020, the Company announced organizational changes, including a workforce reduction of 22 individuals which included a senior officer, that were implemented immediately, subject to certain administrative procedures. In light of the COVID-19 pandemic and market conditions, the Company’s board of directors continues to monitor and evaluate the Company’s business and strategy and to reduce costs and better position the Company for the future.

On September 27, 2019, in connection with the previously announced comprehensive succession planning process, the Company announced that, effective as of October 1, 2019, Randy A. Foutch would transition from his role as Chief Executive Officer. In connection with this transition and in recognition of his efforts as the Company's founder, Mr. Foutch entered into an agreement under which he received the following payments and benefits: (i) a "Founder's Bonus" of $5.9 million approved by the board of directors and (ii) 18 months of COBRA employer contributions that began on October 1, 2019.

On April 2, 2019, the Company announced the retirement of two of its senior officers. Additionally, on April 8, 2019, the Company committed to a company-wide reorganization effort that included a workforce reduction of 20%, which included an executive officer. The reduction in workforce was communicated to employees on April 8, 2019 and implemented immediately, subject to certain administrative procedures. The Company's board of directors approved the reduction in workforce in response to market conditions and to reduce costs and better position the Company for the future.

In connection with these organizational restructurings, the Company incurred one-time charges comprised of compensation, tax, professional, outplacement and insurance-related expenses. The following table reflects the aggregate of these expenses, which is recorded as "Organizational restructuring expenses" on the consolidated statements of operations, for the periods presented:

	Years ended December 31,	
(in thousands)	2020	2019
Organizational restructuring expenses	$ 4,200	$ 16,371

All equity-based compensation awards held by the affected employees were forfeited and the corresponding equity-based compensation was reversed. For additional information on the associated forfeiture activity for the years ended December 31, 2020 and 2019, see Note 9.a. The following table reflects the aggregate of gross equity-based compensation expense reversals in connection with the Company's respective organizational restructurings, which is recorded in "General and administrative" on the consolidated statements of operations, for the periods presented:

	Years ended December 31,	
(in thousands)	2020	2019
Gross equity-based compensation expense reversals	$ (793)	$ (11,706)

Note 19 Subsequent events

a. Senior Secured Credit Facility

On January 14, 2021 and February 22, 2021, the Company borrowed an additional $15.0 million and made a $20.0 million payment, respectively, on the Senior Secured Credit Facility. As a result, the outstanding balance under the Senior Secured Credit Facility was $250.0 million as of February 22, 2021.

b. Commodity derivatives

The following tables present the commodity derivatives that were entered into by the Company subsequent to December 31, 2020:

	Aggregate volumes (Bbl)	Weighted-average price ($/Bbl)	Contract period
Brent ICE - Swaps	2,254,500	$ 55.09	February 2021 - December 2021

	Aggregate volumes (MMBtu)	Weighted-average differential ($/MMBtu)	Contract period
Waha Inside FERC to Henry Hub NYMEX - Basis Swaps	6,823,800	$ (0.26)	March 2021 - December 2021
Waha Inside FERC to Henry Hub NYMEX - Basis Swaps	10,767,500	$ (0.34)	January 2022 - December 2022

The following table presents the commodity derivatives that were sold by the Company subsequent to December 31, 2020, of which the Company received aggregate premiums of $9.0 million at the inception of these contracts:

	Aggregate volumes (Bbl)	Weighted-average price ($/Bbl)	Contract period
Brent ICE - Puts	(2,254,500)	$ 55.00	February 2021 - December 2021

The following table summarizes the resulting open oil and natural gas derivative positions as of December 31, 2020, updated for the above derivative transactions through February 19, 2021, for the settlement periods presented:

	Year 2021	Year 2022
Oil:		
Brent ICE - Puts:		
Volume (Bbl)	209,250	—
Weighted-average floor price ($/Bbl)	$ 55.00	$ —
Brent ICE - Swaps:		
Volume (Bbl)	7,291,500	3,759,500
Weighted-average price ($/Bbl)	$ 51.18	$ 47.05
Brent ICE - Collars:		
Volume (Bbl)	584,000	—
Weighted-average floor price ($/Bbl)	$ 45.00	$ —
Weighted-average ceiling price ($/Bbl)	$ 59.50	$ —
Total Brent ICE:		
Total volume with floor (Bbl)	8,084,750	3,759,500
Weighted-average floor price ($/Bbl)	$ 50.83	$ 47.05
Total volume with ceiling (Bbl)	7,875,500	3,759,500
Weighted-average ceiling price ($/Bbl)	$ 51.79	$ 47.05
Natural gas:		
Henry Hub NYMEX - Swaps:		
Volume (MMBtu)	42,522,500	3,650,000
Weighted-average price ($/MMBtu)	$ 2.59	$ 2.73
Waha Inside FERC to Henry Hub NYMEX - Basis Swaps:		
Volume (MMBtu)	55,332,300	18,067,500
Weighted-average differential ($/MMBtu)	$ (0.48)	$ (0.41)

See Note 10.a for additional discussion regarding the Company's derivatives. There has been no other derivative activity subsequent to December 31, 2020.

Note 20 Supplemental oil, NGL and natural gas disclosures (unaudited)

a. Costs incurred in oil and natural gas property acquisition, exploration and development activities

The following table presents costs incurred in the acquisition, exploration and development of oil and natural gas properties, with asset retirement obligations included in evaluated property acquisition costs and development costs, for the periods presented:

	Years ended December 31,		
(in thousands)	2020	2019	2018
Property acquisition costs:			
Evaluated	$ 11,368	$ 126,372	$ 15,072
Unevaluated	25,549	83,738	2,790
Exploration costs	17,337	19,954	23,884
Development costs	326,823	450,501	607,790
Total oil and natural gas properties costs incurred	$ 381,077	$ 680,565	$ 649,536

b. Aggregate capitalized oil, NGL and natural gas costs

The following table presents the aggregate capitalized costs related to oil, NGL and natural gas production activities with applicable accumulated depletion and impairment as of the dates presented:

(in thousands)	December 31, 2020	December 31, 2019
Gross capitalized costs:		
Evaluated properties	$ 7,874,932	$ 7,421,799
Unevaluated properties not being depleted	70,020	142,354
Total gross capitalized costs	7,944,952	7,564,153
Less accumulated depletion and impairment	(6,817,949)	(5,725,114)
Net capitalized costs	$ 1,127,003	$ 1,839,039

The following table presents a summary of the unevaluated property costs not being depleted as of December 31, 2020, by year in which such costs were incurred:

(in thousands)	2020	2019	2018	2017 and prior	Total
Unevaluated properties not being depleted	$ 32,661	$ 28,266	$ 3,628	$ 5,465	$ 70,020

Unevaluated properties, which are not subject to depletion, are not individually significant and consist of costs for acquiring oil and natural gas leasehold where no evaluated reserves have been identified, including costs of wells being evaluated. The evaluation process associated with these properties has not been completed and therefore, the Company is unable to estimate when these costs will be included in the depletion calculation.

c. Results of operations of oil, NGL and natural gas producing activities

The following table presents the results of operations of oil, NGL and natural gas producing activities (excluding corporate overhead and interest costs) for the periods presented:

(in thousands)	Years ended December 31, 2020	2019	2018
Revenues:			
Oil, NGL and natural gas sales	$ 496,355	$ 706,548	$ 808,530
Production costs:			
Lease operating expenses	82,020	90,786	91,289
Production and ad valorem taxes	33,050	40,712	49,457
Transportation and marketing expenses	49,927	25,397	11,704
Total production costs	164,997	156,895	152,450
Other costs:			
Depletion	203,492	250,857	196,458
Accretion of asset retirement obligations	4,227	3,926	4,233
Impairment expense	889,453	620,565	—
Income tax (benefit) expense[1]	—	(3,257)	4,554
Total other costs	1,097,172	872,091	205,245
Results of operations	$ (765,814)	$ (322,438)	$ 450,835

(1) During each of the years ended December 31, 2020, 2019 and 2018, the Company recorded valuation allowances against its deferred tax assets related to its oil, NGL and natural gas producing activities. Accordingly, the income tax (benefit) expense was computed utilizing the Company's effective tax rate of 0% for the year ended December 31, 2020 and 1% for the years ended December 31, 2019 and 2018, which reflects tax deductions and tax credits and allowances relating to the oil, NGL and natural gas producing activities that are reflected in the Company's "Total income tax benefit (expense)" on the consolidated statements of operations.

d. Net proved oil, NGL and natural gas reserves

Ryder Scott Company, L.P. ("Ryder Scott"), the Company's independent reserve engineers, estimated 100% of the Company's proved reserves as of December 31, 2020, 2019 and 2018. In accordance with SEC regulations, the reserves as of December 31, 2020, 2019 and 2018 were estimated using the Realized Prices, which reflect adjustments to the Benchmark Prices for quality, certain transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the delivery point. See Note 6.a for these Realized Prices. The Company's reserves are reported in three streams: oil, NGL and natural gas.

The SEC has defined proved reserves as the estimated quantities of oil, NGL and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The process of estimating oil, NGL and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates. If such changes are material, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

The following tables provide an analysis of the changes in estimated proved reserve quantities of oil, NGL and natural gas for the years ended December 31, 2020, 2019 and 2018, all of which are located within the U.S.:

	Year ended December 31, 2020			
	Oil (MBbl)	NGL (MBbl)	Natural gas (MMcf)	MBOE
Proved developed and undeveloped reserves:				
Beginning of year	78,639	102,198	675,237	293,377
Revisions of previous estimates	(10,517)	6,218	34,376	1,430
Extensions, discoveries and other additions	4,282	1,811	10,772	7,888
Acquisitions of reserves in place	5,182	1,310	6,948	7,650
Production	(9,827)	(10,615)	(70,049)	(32,117)
End of year	67,759	100,922	657,284	278,228
Proved developed reserves:				
Beginning of year	52,711	90,861	600,334	243,628
End of year	51,751	96,251	633,503	253,586
Proved undeveloped reserves:				
Beginning of year	25,928	11,337	74,903	49,749
End of year	16,008	4,671	23,781	24,642

	Year ended December 31, 2019			
	Oil (MBbl)	NGL (MBbl)	Natural gas (MMcf)	MBOE
Proved developed and undeveloped reserves:				
Beginning of year	61,894	86,647	537,756	238,167
Revisions of previous estimates	(7,865)	5,301	69,678	9,049
Extensions, discoveries and other additions	13,573	12,614	83,345	40,078
Acquisitions of reserves in place	21,413	6,754	44,627	35,605
Production	(10,376)	(9,118)	(60,169)	(29,522)
End of year	78,639	102,198	675,237	293,377
Proved developed reserves:				
Beginning of year	55,893	79,241	491,828	217,105
End of year	52,711	90,861	600,334	243,628
Proved undeveloped reserves:				
Beginning of year	6,001	7,406	45,928	21,062
End of year	25,928	11,337	74,903	49,749

	Year ended December 31, 2018			
	Oil (MBbl)	NGL (MBbl)	Natural gas (MMcf)	MBOE
Proved developed and undeveloped reserves:				
Beginning of year	79,413	67,371	414,592	215,883
Revisions of previous estimates	(20,921)	11,089	72,028	2,173
Extensions, discoveries and other additions	13,330	15,112	93,762	44,069
Acquisitions of reserves in place	596	457	2,810	1,521
Divestitures of reserves in place	(349)	(123)	(756)	(598)
Production	(10,175)	(7,259)	(44,680)	(24,881)
End of year	61,894	86,647	537,756	238,167
Proved developed reserves:				
Beginning of year	68,877	60,441	371,946	191,309
End of year	55,893	79,241	491,828	217,105
Proved undeveloped reserves:				
Beginning of year	10,536	6,930	42,646	24,574
End of year	6,001	7,406	45,928	21,062

The following discussion is for the year ended December 31, 2020. The Company's positive revision of 1,430 MBOE of previously estimated quantities consisted of (i) 29,080 MBOE of positive revisions from performance of proved developed producing wells, (ii) 3,140 MBOE of negative revisions from a decrease in previously estimated quantities of proved undeveloped locations, (iii) 8,245 MBOE of negative revisions due to proved undeveloped locations that were removed due to year-end pricing and (iv) 16,265 MBOE of negative revisions from a decrease in the Realized Prices for oil, NGL and natural gas and other changes to proved wells. Extensions, discoveries and other additions of 7,888 MBOE consisted of (i) 5,347 MBOE that resulted from new wells drilled and (ii) 2,541 MBOE that resulted from new horizontal proved undeveloped locations added in the Company's Howard County, Texas, acreage. Acquisitions of reserves in place of 7,650 MBOE consisted of (i) 367 MBOE from new proved developed wells, (ii) 4,016 MBOE from additional acreage acquired under proved locations in Howard County and (iii) 3,267 MBOE from new proved undeveloped locations in Howard County.

The following discussion is for the year ended December 31, 2019. The Company's positive revision of 9,049 MBOE of previously estimated quantities consisted of (i) 20,858 MBOE of positive revisions from performance of proved developed producing wells, (ii) 12,417 MBOE of negative revisions from a decrease in the Realized Prices for oil, NGL and natural gas and other changes to proved developed producing wells and (iii) 608 MBOE of positive revisions due to proved undeveloped locations that were removed from the development plan in prior years. Extensions, discoveries and other additions of 40,078 MBOE consisted of (i) 24,629 MBOE that resulted from new wells drilled and (ii) 15,449 MBOE that resulted from new horizontal proved undeveloped locations added in our established acreage. Acquisitions of reserves in place of 35,605 MBOE consisted of (i) 1,306 MBOE from new proved developed producing wells and (ii) 34,299 MBOE from 86 new proved undeveloped locations in Howard and western Glasscock Counties of Texas.

The following discussion is for the year ended December 31, 2018. The Company's positive revision of 2,173 MBOE of previously estimated quantities consisted of (i) 11,364 MBOE of negative revisions from performance driven mainly by steeper oil decline curves and tighter well spacing, and a decrease in the Realized Price for natural gas, (ii) 7,045 MBOE of positive revisions from increases in the Realized Prices for oil and NGL and other changes to proved developed producing wells and (iii) 6,492 MBOE of positive revisions due to proved undeveloped locations that were removed from the development plan in prior years, eight of these locations were drilled in 2018 and two were scheduled to be drilled in 2019. Extensions, discoveries and other additions of 44,069 MBOE consisted of (i) 25,617 MBOE that resulted from new wells drilled and (ii) 18,452 MBOE that resulted from new horizontal proved undeveloped locations added.

e. Standardized measure of discounted future net cash flows

The standardized measure of discounted future net cash flows does not purport to be, nor should it be interpreted to present, the fair value of the oil, NGL and natural gas reserves of the property. An estimate of fair value would take into account, among other things, the recovery of reserves not presently classified as proved, the value of proved properties and consideration of expected future economic and operating conditions.

The estimates of future cash flows and future production and development costs as of December 31, 2020, 2019 and 2018 are based on the Realized Prices, which reflect adjustments to the Benchmark Prices for quality, certain transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the delivery point. All Realized Prices are held flat over the forecast period for all reserve categories in calculating the discounted future net cash flows. Any effect from the Company's commodity hedges is excluded. In accordance with SEC regulations, the proved reserves were anticipated to be economically producible from the "as of date" forward based on existing economic conditions, including prices and costs at which economic producibility from a reservoir was determined. These costs, held flat over the forecast period, include development costs, operating costs, ad valorem and production taxes and abandonment costs after salvage. Future income tax expenses are computed using the appropriate year-end statutory tax rates applied to the future pretax net cash flows from proved oil, NGL and natural gas reserves, less the tax basis of the Company's oil and natural gas properties. The estimated future net cash flows are then discounted at a rate of 10%. The Company's unamortized cost of evaluated oil and natural gas properties being depleted exceeded the full cost ceiling for each of the quarterly periods in 2020 and for the third and fourth quarters of 2019 and, as such, the Company recorded non-cash full cost ceiling impairments of $889.5 million and $620.6 million during the years ended December 31, 2020 and 2019, respectively. See Note 6.a for discussion of the Benchmark Prices, Realized Prices and the 2020 and 2019 full cost ceiling impairments recorded.

The following table presents the standardized measure of discounted future net cash flows relating to proved oil, NGL and natural gas reserves for the periods presented:

	Years ended December 31,		
(in thousands)	**2020**	**2019**	**2018**
Future cash inflows	$ 3,824,104	$ 5,702,580	$ 6,266,862
Future production costs	(1,740,537)	(1,994,732)	(1,977,401)
Future development costs	(351,568)	(615,839)	(257,310)
Future income tax expenses	(20,076)	(24,392)	(226,183)
Future net cash flows	1,711,923	3,067,617	3,805,968
10% discount for estimated timing of cash flows	(697,069)	(1,405,356)	(1,691,731)
Standardized measure of discounted future net cash flows	$ 1,014,854	$ 1,662,261	$ 2,114,237

It is not intended that the FASB's standardized measure of discounted future net cash flows represent the fair market value of the Company's proved reserves. The Company cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision, and the 10% discount rate is arbitrary. In addition, prices and costs as of the measurement date are used in the determinations, and no value may be assigned to probable or possible reserves.

The following table presents the changes in the standardized measure of discounted future net cash flows relating to proved oil, NGL and natural gas reserves for the periods presented:

(in thousands)	Years ended December 31, 2020	2019	2018
Standardized measure of discounted future net cash flows, beginning of year	$ 1,662,261	$ 2,114,237	$ 1,770,321
Changes in the year resulting from:			
Sales, less production costs	(331,358)	(549,653)	(656,080)
Revisions of previous quantity estimates	199	36,182	(179,912)
Extensions, discoveries and other additions	60,004	361,479	521,605
Net change in prices and production costs	(770,885)	(900,019)	365,902
Changes in estimated future development costs	64,146	14,876	7,246
Previously estimated development costs incurred during the period	186,261	158,631	207,865
Acquisitions of reserves in place	14,208	207,636	11,411
Divestitures of reserves in place	—	—	(6,015)
Accretion of discount	167,227	217,119	181,693
Net change in income taxes	(1,205)	46,939	(10,340)
Timing differences and other	(36,004)	(45,166)	(99,459)
Standardized measure of discounted future net cash flows, end of year	$ 1,014,854	$ 1,662,261	$ 2,114,237

Estimates of economically recoverable oil, NGL and natural gas reserves and of future net cash flows are based upon a number of variable factors and assumptions, all of which are, to some degree, subjective and may vary considerably from actual results. Therefore, actual production, revenues, development and operating expenditures may not occur as estimated. The reserve data are estimates only, are subject to many uncertainties and are based on data gained from production histories and on assumptions as to geologic formations and other matters. Actual quantities of oil, NGL and natural gas may differ materially from the amounts estimated.

Note 21 Supplemental quarterly financial data (unaudited)

The Company's results by quarter for the periods presented are as follows:

(in thousands, except per share data)	December 31, 2020 First Quarter(1)	Second Quarter(1)	Third Quarter(1)	Fourth Quarter(1)
Revenues	$ 204,992	$ 110,588	$ 173,547	$ 188,065
Operating loss	$ (181,972)	$ (434,052)	$ (167,678)	$ (78,031)
Net income (loss)	$ 74,646	$ (545,455)	$ (237,432)	$ (165,932)
Net income (loss) per common share:(2)				
Basic	$ 6.43	$ (46.75)	$ (20.32)	$ (14.18)
Diluted	$ 6.39	$ (46.75)	$ (20.32)	$ (14.18)

(1) See Note 6.a for discussion of the Company's full cost ceiling impairments recorded.

(2) Per share data was retroactively adjusted to reflect the Company's 1-for-20 reverse stock split effective June 1, 2020, as described in Note 8.a.

(in thousands, except per share data)	December 31, 2019 First Quarter	Second Quarter(1)	Third Quarter(2)	Fourth Quarter(2)
Revenues	$ 208,947	$ 216,643	$ 193,569	$ 218,122
Operating income (loss)	$ 54,397	$ 57,828	$ (350,439)	$ (170,377)
Net income (loss)	$ (9,491)	$ 173,382	$ (264,629)	$ (241,721)
Net income (loss) per common share:(3)				
Basic	$ (0.82)	$ 14.99	$ (22.86)	$ (20.86)
Diluted	$ (0.82)	$ 14.98	$ (22.86)	$ (20.86)

(1) See Note 16.a for discussion of a favorable litigation settlement received.

(2) See Note 6.a for discussion of the Company's full cost ceiling impairments recorded.

(3) Per share data was retroactively adjusted to reflect the Company's 1-for-20 reverse stock split effective June 1, 2020, as described in Note 8.a.