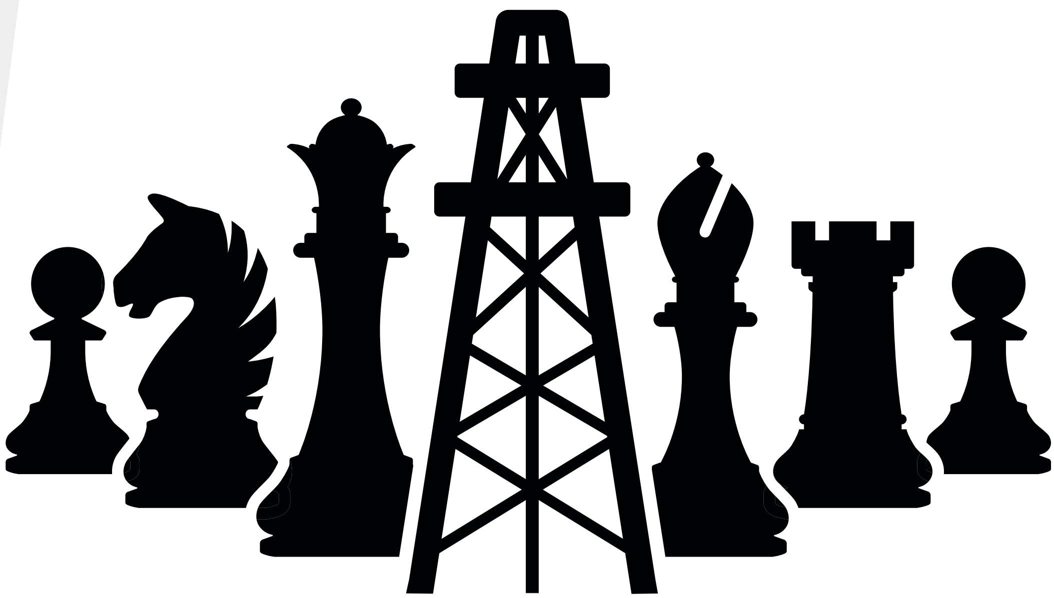
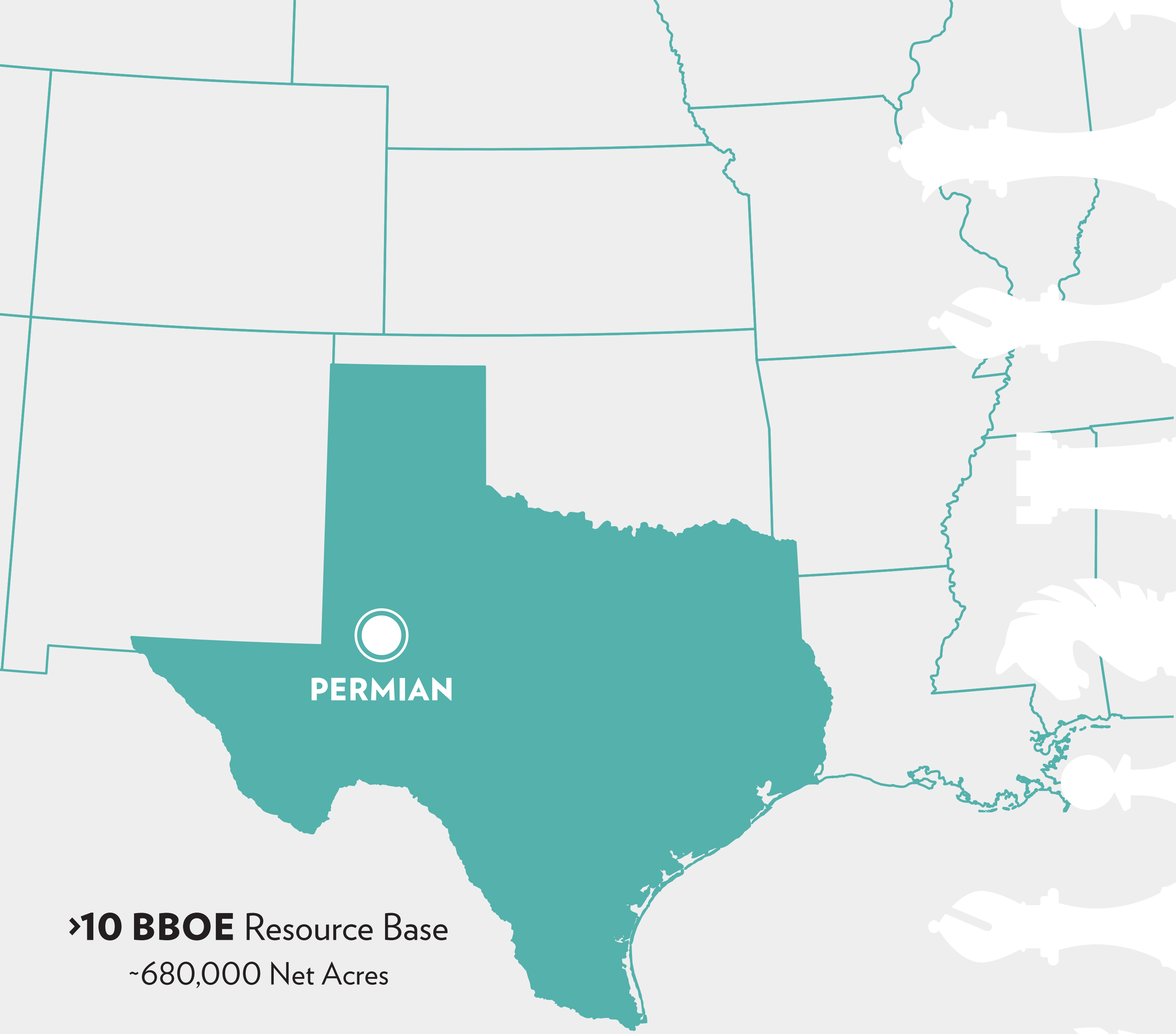


WELL POSITIONED

2019 10-K and Annual Report

PIONEER
NATURAL RESOURCES



›10 BBOE Resource Base
~680,000 Net Acres

Except for historical information contained herein, the statements in this document are forward-looking statements that are made pursuant to the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995. Forward-looking statements and the business prospects of Pioneer Natural Resources Company are subject to several risks and uncertainties that may cause Pioneer's actual results in future periods to differ materially from the forward-looking statements. These risks and uncertainties are described in Items 1, 1A and 7 and on page 5 of Pioneer's Form 10-K included with this report. Pioneer undertakes no duty to publicly update these statements except as required by law.

Cautionary Note – The Securities and Exchange Commission (SEC) prohibits oil and gas companies, in their filings with the SEC, from disclosing estimates of oil or gas resources other than "reserves," as that term is defined by the SEC. In this document, Pioneer includes estimates of quantities of oil and gas using certain terms, such as "resource base," or other descriptions of volumes of reserves, which terms include quantities of oil and gas that may not meet the SEC's definitions of proved, probable and possible reserves, and which the SEC guidelines strictly prohibit Pioneer from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and, accordingly, are subject to substantially greater risk of being recovered by Pioneer. You are urged to consider closely the disclosure in the Company's periodic filings with the SEC.

LETTER TO SHAREHOLDERS

Scott D. Sheffield | President and Chief Executive Officer

FELLOW SHAREHOLDERS

Pioneer Natural Resources had a tremendous year in 2019. We delivered robust well performance, reduced capital spending and increased free cash flow and corporate returns. We accomplished these things while remaining steadfastly committed to environmental, social and governance issues. By executing on our strategic initiatives, delivering strong results and increasing shareholder value, Pioneer is well positioned for the future.

We closed the sale of our Eagle Ford and remaining South Texas assets during the second quarter of 2019. Additionally, Pioneer divested approximately 7,800 net acres of non-core Midland Basin acreage not slated for near-term development for $129 million in 2019. We are operating on a large, highly contiguous leasehold position in the best part of the Midland Basin, and our historical per-acre cost basis is enviable.

"By executing on our strategic initiatives, delivering strong results and increasing shareholder value, Pioneer is **well positioned** for the future."

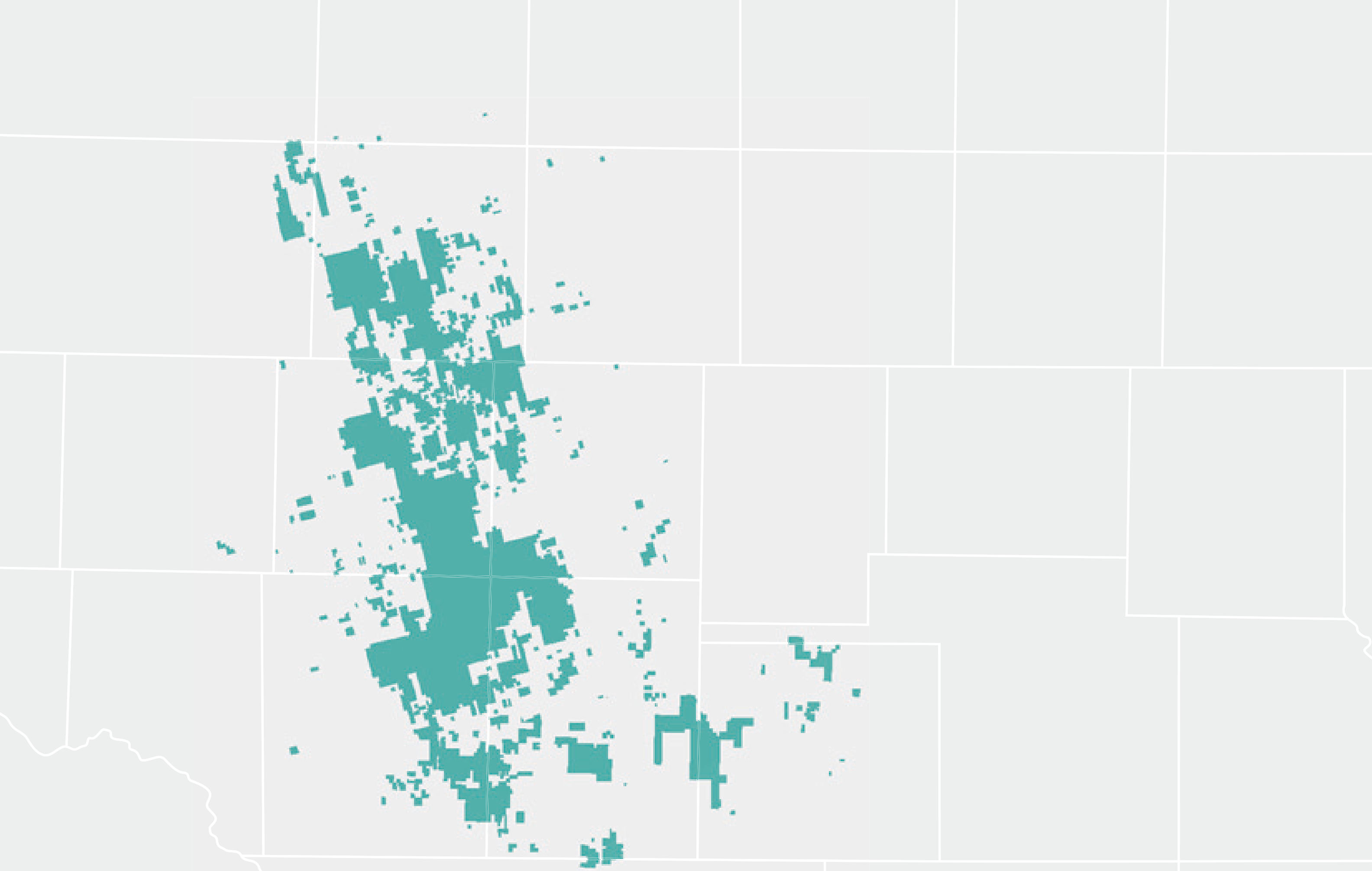
Pioneer achieved significant cost structure reductions in 2019. We completed our corporate restructuring during the second quarter. Through that process, we achieved annual savings on general and administrative expenses of $100 million, and we reduced annual facilities spending by another $100 million by the third quarter, delivering on both objectives ahead of schedule. Streamlining roles and responsibilities and implementing a flatter reporting structure led to tangible improvements in the oversight of capital spending, our drilling program and production operations.

Our returns-focused strategy led to drilling and completions cost reductions and efficiency gains, which led to underspending our 2019 budgeted capital. The number of rigs deployed was at the low end of guidance for 2019, averaging 21, while Pioneer placed 306 wells on production, above the high end of the initial budgeted range of 265 to 290 wells.

In 2019, Pioneer's Permian oil production averaged 211 thousand barrels of oil per day, and our Permian production averaged 341 thousand barrels of oil equivalent per day. We also added Permian proved reserves totaling 302 million barrels of oil equivalent.

Further strengthening our value proposition for shareholders remains a top priority. Over the past three years, Pioneer has increased its return on capital employed from 4% in 2017 and 9% in 2018 to 11% in 2019[1].

[1]Return on capital employed (ROCE) is a non-GAAP financial measure. See schedules for a reconciliation to comparable GAAP numbers.



"We are operating on a large, highly contiguous leasehold position in the best part of the Midland Basin, and **our historical per-acre cost is enviable.**"

Employee volunteers plant trees in Midland to celebrate Earth Day in April 2019.

As part of our strategy to increase shareholder returns, Pioneer's Board of Directors declared a cash dividend of $0.44 per share in the third quarter, equating to $1.76 per share annually. Pioneer also executed $749 million of the $2 billion authorized common stock repurchase program since the December 2018 announcement through the end of 2019.

We'll continue to evaluate other opportunities to improve shareholder returns while maintaining our strong balance sheet. Pioneer had unrestricted cash on hand of $631 million and net debt of $1.7 billion at year end 2019. Pioneer had a $2.1 billion liquidity position at year end, reflecting $631 million of unrestricted cash and a $1.5 billion unsecured credit facility.

2020 OUTLOOK

The global economic impact of COVID-19, combined with the failure of OPEC+ to agree to extend and increase oil production quotas, are having a significant impact on 2020 oil prices. During this challenging environment, we will protect our best-in-class balance sheet and focus on free cash flow generation by reducing our capital budget to a range of $1.7 billion to $1.9 billion, compared to spending $3.0 billion in 2019.

While we are making these capital reductions based on a $30 to $35 WTI oil price outlook for the remainder of 2020, we will continue to monitor the fluid macroeconomic environment and adjust our capital program as needed to preserve our strong financial position. Our financial condition, which is among the best in the energy sector, provides us ample financial flexibility to manage through a period of prolonged low oil prices and positions Pioneer to be stronger when the global economy rebounds. As always, we will operate with an unwavering focus on the health and safety of our employees.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE (ESG)

We view sustainability as a multidisciplinary focus that balances economic growth, environmental stewardship and social responsibility. Pioneer develops natural resources while supporting surrounding communities and protecting the environment.

Intently focused on reducing emissions and emission intensities, Pioneer reduced its greenhouse gas (GHG) emissions by 24% between 2016 and 2018. Additionally, total GHG emission intensity decreased by 38%, and methane intensity dropped 41%. More recently, between January 2018 and July 2019, Pioneer limited flaring to less than 2% of its produced gas, one of the lowest flaring percentages of operators in the Permian Basin. Our proactive measures, including aerial monitoring of 100% of Permian facilities for leak detection and repair and producing a well only once it's fully connected to a gas line, combine to make Pioneer a leader in environmental stewardship.

For years Pioneer has focused on reducing its use of freshwater by increasing reuse of produced water and working with the cities of Midland and Odessa to acquire treated effluent water. After the new Midland water treatment facility comes online in late 2020, Pioneer expects to reduce its freshwater use to below 20% in 2021 and to reduce freshwater use further over the next few years.

Socially, Pioneer maintains a proactive safety culture, supports a diverse workforce and inspires teamwork to drive innovation. Our Board of Directors has a Health, Safety and Environment Committee and a Nominating and Corporate Governance Committee to ensure that proper ESG protocols are in place and to promote a culture of continuous improvement in safety and environmental practices.

We issued our third annual Sustainability Report in August 2019, available at www.pxd.com/sustainability. In the report, we illustrate Pioneer's unwavering commitment to these issues, based on metrics compiled for full-year 2018.

OUR PEOPLE

Pioneer is committed to creating an inclusive environment where all employees feel respected, valued and connected to the business. I'd like to thank our employees for their hard work, strong will and determination in 2019. Their perseverance to achieve at the highest level drives our company forward.

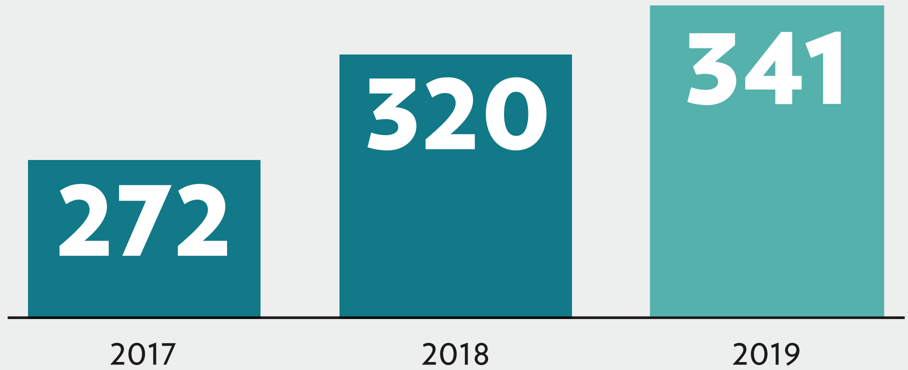
I also admire employees for consistently giving back to the communities where they live and work by volunteering their personal time and donating generously with the support of Pioneer matching funds and sponsorships. Important local organizations such as Habitat for Humanity, Dallas CASA, United Way and the Midland Independent School District – just to name a handful – were beneficiaries of our collective goodwill last year.

Thank you for investing in our company.

Sincerely,

Scott D. Sheffield
President and CEO

PERMIAN ANNUAL PRODUCTION IN MBOEPD

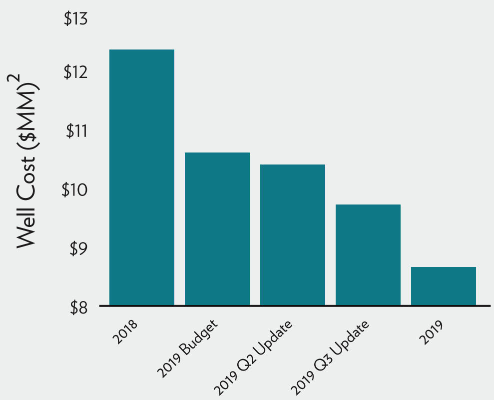


PERMIAN ACQUISITION COST PER ACRE

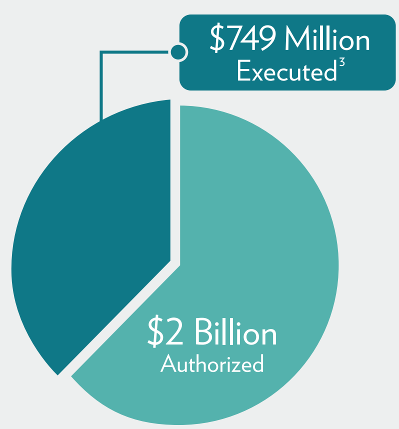
PXD: ~$500

Peers[1]: ~$34,000

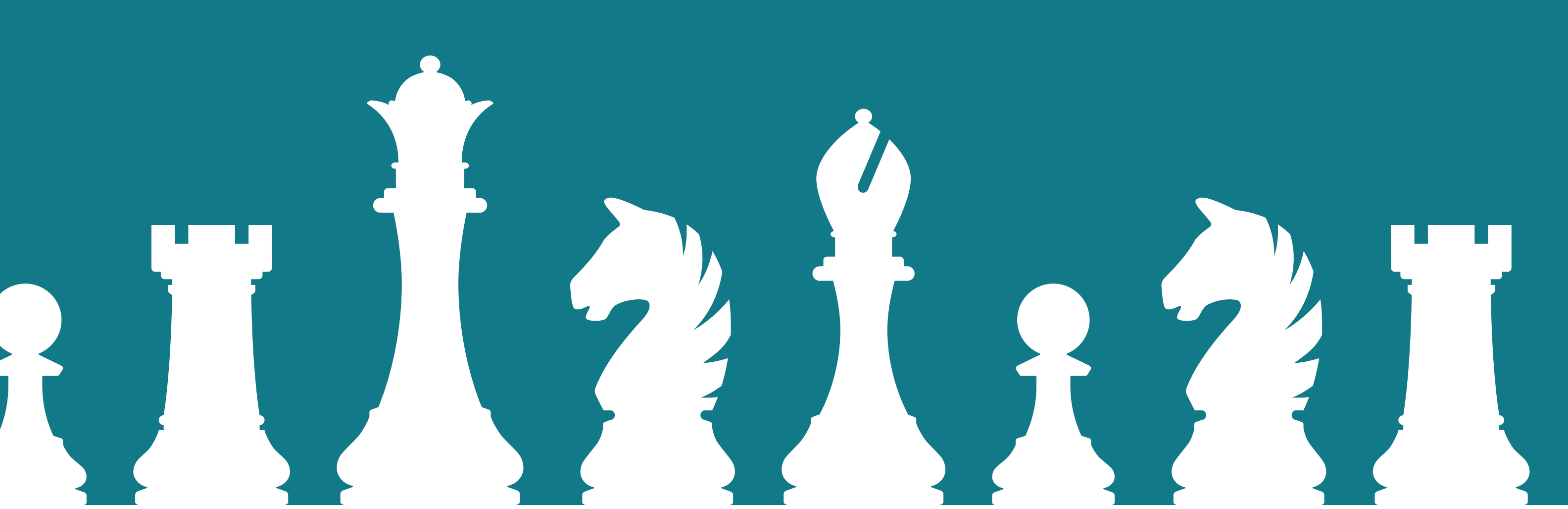
~30% REDUCTION IN WELL COSTS DURING 2019



COMMON STOCK REPURCHASE PROGRAM



1) Source: PLS. Transactions of $100 MM or greater since 2017. Peers: CXO, FANG, MRO, NBL, PE and XEC. 2) 2018 and 2019 represent drilling, completion and facilities (D, C & F) capital divided by wells placed on production (POP) for each respective year. Budget and Quarterly Updates reflect the midpoint of D, C & F capital guidance divided by the midpoint of POP guidance. 3) Includes share repurchases from 12/13/2018 through 12/31/2019.



BOARD OF DIRECTORS

Members of the Board of Directors are (L to R): Andrew Cates, Ted Buchanan, Stacy Methvin, Larry Grillot, Mona Sutphen, Royce Mitchell, Scott Sheffield, Frank Risch, Ken Thompson, Phillip Gobe, Michael Wortley and Phoebe Wood

J. Kenneth Thompson [2,4]
Chairman of the Board
President and CEO,
Pacific Star Energy LLC

Edison C. Buchanan [2,4]
Former Managing
Director, Credit
Suisse First Boston

Andrew F. Cates [1,4]
Managing Member,
Value Acquisition Fund

Phillip A. Gobe
Chairman and CEO,
ProPetro Holding Corp.

Larry R. Grillot [1,3]
Retired Dean, Mewbourne
College of Earth and
Energy, The University
of Oklahoma

Stacy P. Methvin [2,3]
Retired Vice President,
Shell Oil Company

Royce W. Mitchell [1,3]
Executive Consultant

Frank A. Risch [1,4]
Retired Vice President and
Treasurer, Exxon Mobil
Corporation

Scott D. Sheffield
President and
Chief Executive Officer

Mona K. Sutphen [2,3]
Senior Advisor,
The Vistria Group LLC

Phoebe A. Wood [2,4]
Retired Vice Chairman and
Chief Financial Officer,
Brown-Forman Corporation

Michael D. Wortley [1,4]
Chief Legal Officer,
Reata Pharmaceuticals, Inc.

COMMITTEE MEMBERSHIP:

[1] Audit Committee [2] Compensation and Leadership Development Committee

[3] Health, Safety and Environment Committee [4] Nominating and Corporate Governance Committee

OFFICERS

Members of the Management Committee showed up in force to support the Giving Fair in December 2019, where charitable organizations educated employees about their mission and services. Pictured are (L to R): Meredith Skirbe, Neal Shah, Amy Majerczyk, Stephanie Stewart, Chris Cheatwood and Beth McDonald

Scott D. Sheffield
President and Chief Executive Officer

Mark S. Berg
Executive Vice President, Corporate Operations

Chris J. Cheatwood
Executive Vice President, Field Development and Emerging Technology

Richard P. Dealy
Executive Vice President and Chief Financial Officer

J.D. Hall
Executive Vice President, Operations

Mark H. Kleinman
Executive Vice President and General Counsel

John C. Distaso
Senior Vice President, Marketing

Robert C. Hagens
Senior Vice President, Land

Bonnie S. Black
Vice President, Drilling

Craig Kuiper
Vice President, Production Operations

Beth McDonald
Vice President, Permian Strategic Planning and Field Development

Margaret M. Montemayor
Vice President and Chief Accounting Officer

Thaddeus J. Owens
Vice President, Communications and Government Relations

Christopher M. Paulsen
Vice President, Business Development

Neal H. Shah
Vice President, Investor Relations

Susan A. Spratlen
Vice President, Permian Affairs

Stephanie D. Stewart
Vice President and Chief Information Officer

Tyson Taylor
Vice President, Human Resources

Thomas J. Murphy
Corporate Secretary

Midland employees walk and "Carry The Load," part of a national movement to honor the sacrifices of veterans, military and first responders and their families in May 2019.

Chief Information Security Officer Gregory Wilson and board member Mona Sutphen at the Black History Month celebration in Las Colinas in February 2019.

Midland employee volunteers at a Habitat for Humanity build site in May 2019.

The Dallas CASA Classic invitational golf tournament, co-hosted by Pioneer, netted $1.8 million for this wonderful charity in April 2019.

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, 2019
or

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

For the transition period from ________ to ________
Commission File Number: 1-13245

PIONEER NATURAL RESOURCES COMPANY

(Exact name of registrant as specified in its charter)

Delaware	75-2702753
(State or other jurisdiction of incorporation)	(I.R.S. Employer Identification No.)

777 Hidden Ridge
Irving, Texas 75038
(Address of principal executive offices and zip code)

(972) 444-9001
(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, par value $.01 per share	PXD	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 and post 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.

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 is a shell company (as defined in Rule 12b-2 of the Act). **Yes** ☐ **No** ☒

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter	**$ 25,544,329,552**
Number of shares of Common Stock outstanding as of February 18, 2020	**165,714,771**

DOCUMENTS INCORPORATED BY REFERENCE:

(1) Portions of the Definitive Proxy Statement for the Company's Annual Meeting of Shareholders to be held in May 2020 are incorporated into Part III of this report.

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TABLE OF CONTENTS

Definitions of Certain Terms and Conventions Used Herein

Within this Report, the following terms and conventions have specific meanings:

- ***"Bbl"*** means a standard barrel containing 42 United States gallons.
- ***"Bcf"*** means one billion cubic feet and is a measure of gas volume.
- ***"BOE"*** means a barrel of oil equivalent and is a standard convention used to express oil and gas volumes on a comparable oil equivalent basis. Gas equivalents are determined under the relative energy content method by using the ratio of six thousand cubic feet of gas to one Bbl of oil or natural gas liquid.
- ***"BOEPD"*** means BOE per day.
- ***"Brent"*** means Brent oil price, a major trading classification of light sweet oil that serves as a benchmark price for oil worldwide.
- ***"Btu"*** means British thermal unit, which is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
- ***"DD&A"*** means depletion, depreciation and amortization.
- ***"Field fuel"*** means gas consumed to operate field equipment (primarily compressors) prior to the gas being delivered to a sales point.
- ***"GAAP"*** means accounting principles generally accepted in the United States of America.
- ***"GHG"*** means greenhouse gases.
- ***"HH"*** means Henry Hub, a distribution hub in Louisiana that serves as the delivery location for gas futures contracts on the NYMEX.
- ***"MBbl"*** means one thousand Bbls.
- ***"MBOE"*** means one thousand BOEs.
- ***"Mcf"*** means one thousand cubic feet and is a measure of gas volume.
- ***"MMBbl"*** means one million Bbls.
- ***"MMBOE"*** means one million BOEs.
- ***"MMBtu"*** means one million Btus.
- ***"MMcf"*** means one million cubic feet.
- ***"Mont Belvieu"*** means the daily average natural gas liquids components as priced in *OPIS* in the table "U.S. and Canada LP – Gas Weekly Averages" at Mont Belvieu, Texas.
- ***"NGLs"*** means natural gas liquids, which are the heavier hydrocarbon liquids that are separated from the gas stream; such liquids include ethane, propane, isobutane, normal butane and natural gasoline.
- ***"NYMEX"*** means the New York Mercantile Exchange.
- ***"NYSE"*** means the New York Stock Exchange.
- ***"Pioneer"*** or the ***"Company"*** means Pioneer Natural Resources Company and its subsidiaries.
- ***"Proved developed reserves"*** mean reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.
- ***"Proved reserves"*** mean those quantities of oil and gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

  (i) The area of the reservoir considered as proved includes: (A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

  (ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons ("LKH") as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty.

  (iii) Where direct observation from well penetrations has defined a highest known oil ("HKO") elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

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

  (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

  (ii) Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

  (iii) Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.
- ***"SEC"*** means the United States Securities and Exchange Commission.
- ***"Standardized Measure"*** means the after-tax present value of estimated future net cash flows of proved reserves, determined in accordance with the rules and regulations of the SEC, using prices and costs employed in the determination of proved reserves and a ten percent discount rate.
- ***"U.S."*** means United States.
- ***"WTI"*** means West Texas Intermediate, a light sweet blend of oil produced from fields in western Texas and is a grade of oil used as a benchmark in oil pricing.
- With respect to information on the working interest in wells, drilling locations and acreage, ***"net"*** wells, drilling locations and acres are determined by multiplying ***"gross"*** wells, drilling locations and acres by the Company's working interest in such wells, drilling locations or acres. Unless otherwise specified, wells, drilling locations and acreage statistics quoted herein represent gross wells, drilling locations or acres.
- All currency amounts are expressed in U.S. dollars.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this "Report") contains forward-looking statements that involve risks and uncertainties. When used in this document, the words "believes," "plans," "expects," "anticipates," "forecasts," "intends," "continue," "may," "will," "could," "should," "future," "potential," "estimate," or the negative of such terms and similar expressions as they relate to the Company are intended to identify forward-looking statements, which are generally not historical in nature. The forward-looking statements are based on the Company's current expectations, assumptions, estimates and projections about the Company and the industry in which the Company operates. Although the Company believes that the expectations and assumptions reflected in the forward-looking statements are reasonable as and when made, they involve risks and uncertainties that are difficult to predict and, in many cases, beyond the Company's control. In addition, the Company may be subject to currently unforeseen risks that may have a materially adverse effect on it. Accordingly, no assurances can be given that the actual events and results will not be materially different from the anticipated results described in the forward-looking statements. See "Item 1. Business — Competition, Markets and Regulations," "Item 1A. Risk Factors," "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for a description of various factors that could materially affect the ability of Pioneer to achieve the anticipated results described in the forward-looking statements. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. The Company undertakes no duty to publicly update these statements except as required by law.

PART I

ITEM 1. BUSINESS

General

Pioneer is a large independent oil and gas exploration and production company that explores for, develops and produces oil, NGLs and gas within the United States, with operations in the Permian Basin in West Texas. The Company is a Delaware corporation, and its common stock has been listed and traded on the NYSE under the ticker symbol "PXD" since its formation in 1997.

The Company's principal executive office is located at 777 Hidden Ridge, Irving, Texas, 75038. The Company also maintains an office in Midland, Texas and field offices in its area of operation.

At December 31, 2019, Pioneer had 2,323 employees, 826 of whom were employed in field operations and 360 of whom were employed in vertical integration activities.

Available Information

Pioneer files or furnishes annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934 (the "Exchange Act"). The SEC maintains a website (www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers, including Pioneer, that file electronically with the SEC.

The Company makes available free of charge through its website (www.pxd.com) its Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after it electronically files such material with, or furnishes it to, the SEC. In addition to the reports filed or furnished with the SEC, Pioneer publicly discloses information from time to time in its press releases and investor presentations that are posted on its website or publicly during accessible investor conferences. Such information, including information posted on or connected to the Company's website, is not a part of, or incorporated by reference in, this Report or any other document the Company files with or furnishes to the SEC.

Mission and Strategies

The Company's mission is to be America's leading independent energy company, focused on value, safety, the environment, technology and our greatest asset, our people. The Company's long-term growth strategy is centered around the following strategic objectives:

- maintaining a strong balance sheet to ensure financial flexibility;
- delivering economic production and reserve growth through drilling, completion and production improvement activities;
- utilizing the Company's scale and technology advancements to reduce costs and improve efficiency;
- returning free cash flow to investors through a combination of dividends and share repurchases;
- developing and training employees and contractors to perform their jobs in a safe manner; and
- stewarding the environment through industry leading sustainable development efforts.

The Company's long-term strategy is anchored by the Company's interests in the long-lived Spraberry/Wolfcamp oil field located in the Permian Basin in West Texas, which has an estimated remaining productive life in excess of 50 years.

Business Activities

Pioneer's purpose is to competitively and profitably explore for, develop and produce oil and gas reserves. In so doing, the Company sells homogeneous oil, NGL and gas units that, except for geographic and relatively minor quality differences, cannot be significantly differentiated from units offered for sale by the Company's competitors. The Company's portfolio of resources and opportunities are located in the Spraberry/Wolfcamp oil field, and provide long-lived, dependable production and lower-risk exploration and development opportunities.

Petroleum industry. Over the past several years, the oil price environment has been characterized by high volatility. During 2019, Brent oil prices rose to a high of $74.57 per barrel in April 2019, up from a low of $54.91 per barrel in early January 2019. During 2020 to date, Brent oil prices declined to a low of $49.45 in February 2020. Significant factors that are likely to affect 2020 commodity prices include: the effect of U.S. energy, monetary, environmental and trade policies, including policies related to U.S. and China trade negotiations and Iranian oil sanctions; fiscal challenges facing the United States federal government; the pace of economic growth in the U.S. and throughout the world; geopolitical issues globally, especially in the Middle East; the extent to which Organization of Petroleum Exporting Countries ("OPEC") members and some nonmembers, including Russia, adhere to and agree to extend their oil production quota's; uncertain demand fundamentals in 2020 and beyond, led by rising oil consumption in China and India offset by European Union members reshaping their fossil fuel consumption towards lower carbon energy; overall North American and worldwide gas supply and demand fundamentals, including the timing of incremental LNG export capacity additions; and global or national health concerns, including the outbreak of pandemic or contagious disease, such as the recent coronavirus, which may reduce demand for oil, NGL and gas because of reduced global or national economic activity. Because the global economic and political outlook and commodity price environment are uncertain, the Company endeavors to maintain a strong financial liquidity position to provide financial flexibility should commodity prices decline and remain low for an extended period of time.

While the industry has invested in initiatives designed to increase oil, NGL and gas takeaway capacity associated with growing U.S. shale production, such as the construction of additional oil and NGL export facilities and new liquefied natural gas ("LNG") facilities, the supply of these products has increased at a faster pace than the overall U.S. and international demand for these commodities. Oil, NGL products and gas supplies are expected to continue to increase during 2020 and prices are expected to remain volatile. To mitigate this risk, Pioneer enters into pipeline capacity commitments in order to secure available oil, NGL and gas transportation capacity from the Company's area of production with the objective of transporting a significant portion of the Company's oil and gas sales to higher priced markets. Specifically, the Company has entered into purchase transactions with third parties and separate sale transactions with third parties to diversify a portion of the Company's oil and gas sales to Gulf Coast refineries and LNG facilities, international export markets and to satisfy unused gas pipeline capacity commitments. These marketing activities provided incremental cash flow of $283 million in 2019 and $458 million in 2018, compared to cash outlays of $31 million in 2017.

The Company also uses commodity derivative contracts to mitigate the effect of commodity price volatility on the Company's net cash provided by operating activities and its net asset value. The Company has entered into derivative contracts for a portion of its forecasted 2020 production; consequently, if commodity prices decline, the Company could realize lower prices for volumes not protected by the Company's derivative activities and could see a reduction in derivative contract prices available on additional volumes in the future. As a result, the Company's internal cash flows will be negatively impacted by a reduction in commodity prices or to the extent that sales prices do not cover the third-party purchase price and cost of transportation for that portion of volumes transported to other markets. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note 5 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Liquidity. The Company's primary needs for cash are for (i) capital expenditures, (ii) acquisitions of oil and gas properties, (iii) payments of contractual obligations, including debt maturities, (iv) dividends and share repurchases and (v) working capital obligations. Funding for these cash needs may be provided by any combination of the Company's primary sources of liquidity including: (i) cash and cash equivalents, (ii) net cash provided by operating activities, (iii) sales of investments, (iv) unused borrowing capacity under its credit facility, (v) issuances of debt or equity securities and (vi) other sources, such as sales of nonstrategic assets. Although the Company expects that these sources of funding will be adequate to fund its 2020 capital expenditures, dividend payments and provide adequate liquidity to fund other needs, including stock repurchases, no assurance can be given that such funding sources will be adequate to meet the Company's future needs.

Production. The Company focuses its efforts towards maximizing its average daily production of oil, NGLs and gas through development drilling, production enhancement activities and acquisitions of producing properties, while minimizing controllable costs associated with production activities. For the year ended December 31, 2019, the Company's production of 126 MMBOE, excluding field fuel usage, represented an eight percent increase compared to production during 2018. See "Item 2. Properties — Selected Oil and Gas Information — Production, price and cost data" for additional information.

Drilling activities. The Company believes that its current property base provides a substantial inventory of prospects for future reserve, production and cash flow growth.

Development activities. The Company seeks to increase its proved oil and gas reserves, production and cash flow through development drilling and by conducting other production enhancement activities, such as well recompletions. The Company's proved reserves as of December 31, 2019 include proved undeveloped reserves and proved developed non-producing reserves of 39 MMBbls of oil, 16 MMBbls of NGL and 83 Bcf of gas. The timing of the development of these proved reserves will be dependent upon commodity prices, drilling and operating costs and the Company's expected operating cash flows and financial condition. During the three years ended December 31, 2019, the Company drilled 854 gross (745 net) exploration and development wells, with 98 percent of the gross wells (99 percent of net wells) being successfully completed as productive wells, at a total drilling cost (net to the Company's interest) of $9.2 billion, including infrastructure capital.

Exploratory activities. The Company has a significant portfolio of lower-risk exploration opportunities that are expected to be evaluated and tested in the future. Exploratory and extension drilling involve greater risks of dry holes or failure to find commercial quantities of hydrocarbons than development drilling or enhanced recovery activities.

Acquisition activities. The Company regularly seeks to acquire or trade for acreage that complements its operations, provides exploration and development opportunities, increases the lateral length of future horizontal wells and potentially provides superior returns on investment. The Company periodically evaluates and pursues acquisition and acreage trade opportunities (including opportunities to acquire particular oil and gas assets or entities owning oil and gas assets and opportunities to engage in mergers, consolidations or other business combinations with such entities) and at any given time may be in various stages of evaluating such opportunities. Such stages may take the form of internal financial analyses, oil and gas reserve analyses, due diligence, the submission of indications of interest, preliminary negotiations, negotiations of letters of intent or negotiations of definitive agreements. The success of any acquisition or acreage trade is uncertain and depends on a number of factors, some of which are outside the Company's control.

During 2019, 2018 and 2017, the Company spent $28 million, $65 million and $136 million, respectively, primarily to purchase undeveloped acreage for future exploitation and exploration activities in the Spraberry/Wolfcamp field of the Permian Basin. See Note 3 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Integrated Services. The Company continues to utilize its integrated services to control well costs and operating costs in addition to supporting the execution of its drilling and production activities. The Company owns field service equipment that supports its drilling and production operations, including pulling units, fracture stimulation tanks, water transport trucks, hot oilers, blowout preventers, construction equipment and fishing tools.

The Company continues to construct a field-wide water distribution system to reduce the cost of water for drilling and completion activities and to secure adequate supplies of water to support the Company's long-term growth plan for the Spraberry/Wolfcamp field. During 2019, the Company expanded its mainline system, subsystems and frac ponds to efficiently deliver water to Pioneer's drilling locations. The Company is purchasing approximately 120 thousand barrels per day of effluent water from the City of Odessa and is partnering with the City of Midland to upgrade the city's wastewater treatment plant in return for approximately two billion barrels of low-cost, non-potable water over a 28-year contract period (up to 240 thousand barrels per day) to support its drilling and completion activities. The Midland wastewater treatment plant is scheduled for completion in early 2021.

Asset divestitures. The Company regularly reviews its asset base to identify nonstrategic assets, the disposition of which would increase capital resources available for other activities, create organizational and operational efficiencies and further the Company's objective of maintaining a strong balance sheet to ensure financial flexibility.

See Note 3 and Note 4 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Marketing of Production

General. Production from the Company's properties is marketed using methods that are consistent with industry practices. Sales prices for oil, NGL and gas production are negotiated based on factors normally considered in the industry, such as an index or spot price, price regulations, distance from the well to the pipeline, commodity quality and prevailing supply and demand conditions. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional information.

Seasonal nature of business. Generally, but not always, the demand for gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers may impact general seasonal changes in demand.

Significant purchasers. During 2019 the Company's oil, NGL and gas sales to Sunoco Logistics Partners L.P., Occidental Energy Marketing Inc. and Plains Marketing L.P. accounted for 33 percent, 20 percent and 13 percent of the Company's oil and gas revenues, respectively. The loss of one of these significant purchasers or an inability to secure adequate pipeline, gas plant and NGL fractionation infrastructure for its Permian Basin production could have a material adverse effect on the Company's ability to produce and sell its oil, NGL and gas production.

Revenues from sales of purchased oil and gas to Occidental Energy Marketing Inc. accounted for 30 percent of the Company's sales of purchased oil and gas. No other purchaser of oil or gas purchased by the Company from third parties exceeded ten percent during 2019. The loss of this significant purchaser of purchased oil and gas would not be expected to have a material adverse effect on the Company's ability to sell commodities it purchases from third parties.

See Note 13 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Derivative risk management activities. The Company primarily utilizes commodity swap contracts, collar contracts, collar contracts with short puts and basis swap contracts that are intended to (i) reduce the effect of price volatility on the commodities the Company produces and sells or consumes, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. From time to time, the Company also utilizes interest rate derivative contracts intended to reduce the effect of interest rate volatility on the Company's indebtedness.

The Company enters into pipeline capacity commitments in order to secure available oil, NGL and gas transportation capacity from the Company's areas of production. The Company enters into purchase transactions with third parties and separate sale transactions with third parties to diversify a portion of the Company's oil and gas sales to Gulf Coast refineries and LNG facilities, international export markets and to satisfy unused gas pipeline capacity commitments.

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note 5 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Competition, Markets and Regulations

Competition. The oil and gas industry is highly competitive in the exploration for and acquisition of reserves, the acquisition of oil and gas leases, marketing of oil, NGL and gas production, the obtaining of equipment and services and the hiring and retention of staff necessary for the identification, evaluation, operation and acquisition and development of oil and gas properties. The Company's competitors include a large number of companies, including major integrated oil and gas companies, other independent oil and gas companies, and individuals engaged in the exploration for and development of oil and gas properties. The Company also faces competition from companies that supply alternative sources of energy, such as wind and solar power. Competition will increase as alternative energy technology becomes more reliable and governments throughout the world support or mandate the use of such alternative energy. Additionally, various entities throughout the world, including governments and public and private companies, are promoting research into new technologies to accelerate the implementation of alternative energy sources.

Competitive advantage is gained in the oil and gas exploration and development industry by employing well-trained and experienced personnel who make prudent capital investment decisions based on management direction, embrace technological innovation and are focused on price and cost management. The Company has a team of dedicated employees who represent the professional disciplines and sciences that the Company believes are necessary to allow Pioneer to maximize the long-term profitability and net asset value inherent in its physical assets.

See "Item 1A. Risk Factors - The Company faces significant competition and some of its competitors have resources in excess of the Company's available resources" for additional information.

Markets. The Company's ability to produce and market oil, NGL and gas profitably depends on numerous factors beyond the Company's control. The effect of these factors cannot be accurately predicted or anticipated. Although the Company cannot predict the occurrence of events that may affect commodity prices or the degree to which commodity prices will be affected, the prices for any commodity that the Company produces will generally approximate current market prices in the geographic region of the production unless the Company effectively enhances margins through marketing and derivative arrangements.

Securities regulations. Enterprises that sell securities in public markets are subject to regulatory oversight by agencies such as the SEC and the NYSE. This regulatory oversight imposes on the Company many requirements, including the responsibility for establishing and maintaining disclosure controls and procedures and internal controls over financial reporting, and ensuring that the financial statements and other information included in submissions to the SEC do not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made in such submissions not misleading. Failure to comply with the rules and regulations of the SEC could subject the Company to litigation from public or private plaintiffs. Failure to comply with the rules of the NYSE could result in the de-listing of the Company's common stock, which would have an adverse effect on the market price and liquidity of the Company's common stock. Compliance with some of these rules and regulations is costly, and regulations are subject to change or reinterpretation.

Environmental and occupational health and safety matters. The Company's operations are subject to stringent federal, state and local laws and regulations governing worker health and safety, the discharge of materials into the environment and environmental protection. Numerous governmental entities, including the U.S. Environmental Protection Agency (the "EPA"), the U.S. Occupational Safety and Health Administration ("OSHA") and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, which may cause the Company to incur significant capital expenditures or take costly actions to achieve and maintain compliance. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, imposition of investigatory remedial or corrective action of obligations, the occurrence of delays or restrictions in permitting or the performance of projects and the issuance of orders enjoining the Company from conducting certain operations in a particular area. While the Company's environmental compliance costs have historically not had a material adverse effect on its results of operations, there can be no assurance that such costs will not be material in the future, or that new or more stringently applied laws and regulations will not materially increase the cost of doing business.

The following is a summary of the more significant environmental and worker health and safety laws, as amended from time to time, to which the Company's business operations are or may be subject and with which compliance or the failure to maintain compliance may have a material adverse effect on the Company's capital expenditures, results of operations or financial position.

Hazardous wastes and substances. The federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the authority delegated by the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. The Company generates some amounts of ordinary industrial wastes that may be regulated as RCRA hazardous wastes. RCRA currently excludes from the definition of hazardous waste drilling fluids, produced waters and certain other wastes associated with the exploration, development and production of oil or gas. These wastes are instead regulated under RCRA's less stringent non-hazardous waste provisions. There have been efforts from time to time to remove this exclusion. For example, in response to a federal consent decree issued in 2016, the EPA was required during 2019 to determine whether certain Subtitle D criteria regulations required revision in a manner that could result in oil and gas wastes being regulated as RCRA hazardous wastes. In April 2019, the EPA made a determination that such revision of the regulations was unnecessary. Any future loss of the RCRA exclusion could have a material adverse effect on the Company's results of operations and financial position, and it is possible that certain oil and gas exploration and production wastes now classified as non-hazardous could be classified as hazardous waste in the future.

The federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, and analogous state laws impose joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include: (i) the current owner or operator of the site where the release occurred, (ii) a past owner or operator of the site at the time of the disposal of the hazardous substance and (iii) anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to 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 public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. The Company generates materials in the course of its operations that may be regulated as CERCLA hazardous substances.

See "Item 1A. Risk Factors - The nature of the Company's assets and production operations may impact the environment or cause environmental contamination, which could result in material liabilities to the Company" for additional information.

Water use, surface discharges and injections into underground formations. The federal Water Pollution Control Act, also known as the Clean Water Act (the "CWA"), and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and hazardous substances, into waters of the United States and state waters. Spill prevention, control and countermeasure plan requirements imposed under the CWA require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon spill, rupture or leak. Additionally, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of stormwater runoff from certain types of facilities. The CWA also prohibits the discharge of dredge and fill material into regulated waters, including wetlands, unless authorized by an appropriately issued permit. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, as well as require remedial or mitigation measures, for noncompliance with discharge permits or other requirements of the CWA and analogous state laws.

The federal Oil Pollution Act ("OPA") sets minimum standards for prevention, containment and cleanup of oil spills into waters of the United States. Under OPA, responsible parties, including owners and operators of onshore facilities, such as exploration and production facilities, may be held strictly liable for oil spill cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. OPA amends the CWA and thus noncompliance with OPA could result in civil and criminal penalties under the CWA.

The Company may dispose of produced water from oil and gas activities in underground injection wells, which are designed and permitted to place the water into non-productive geologic formations that are isolated from fresh water sources. The Underground Injection Control ("UIC") program established under the federal Safe Drinking Water Act ("SDWA") requires issuance of permits from the EPA or an analogous state agency for the construction and operation of these disposal wells. Additionally, the UIC program establishes minimum standards for disposal well operations and restricts the types and quantities of fluids that may be disposed. Because some states have become concerned that the disposal of produced water into underground formations could contribute to seismicity, they have adopted or are considering adopting additional regulations governing such disposal. Should future bans relating to underground injection wells be placed in effect in the Permian Basin, where the Company has significant operations, there could be an adverse impact on the Company's ability to operate.

See "Item 1A. Risk Factors - The Company's operations are subject to stringent environmental, oil and gas-related and occupational safety and health laws and regulations that could cause it to delay, curtail or cease its operations or expose it to material costs and liabilities" and "Item 1A. Risk Factors - The Company's operations are substantially dependent upon the availability of water and its ability to dispose of produced water gathered from drilling and production activities. Restrictions on the Company's ability to obtain water or dispose of produced water may have a material adverse effect on its financial condition, results of operations and cash flows" for additional information.

Hydraulic fracturing. Hydraulic fracturing is an important and common practice to stimulate production of oil and gas from dense subsurface rock formations. The process involves the injection of water, sand and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate oil and gas production. The Company routinely conducts hydraulic fracturing in its drilling and completion programs. The process is typically regulated by state oil and gas commissions, but, in recent years, several federal, state and local agencies have asserted regulatory authority over certain aspects of the process. Additionally, the threat of climate change has resulted in increasing political risks in the United States, including climate-related pledges to ban hydraulic fracturing of oil and gas wells being made by certain candidates seeking the office of President of the United Sates in 2020. In the event federal, state or local restrictions are adopted in areas where the Company is currently conducting operations, or in the future plans to conduct operations, the Company may incur additional costs to comply with such requirements that may be significant in nature, experience delays, curtailment or a cessation in the pursuit of exploration, development or production activities, and be limited or precluded in the drilling of wells or the volume that the Company is ultimately able to produce from its reserves.

See "Item 1A. Risk Factors - Laws and regulations regarding hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs and additional operating restrictions, delays or cancellations and have a material adverse effect on the Company's production" and "Item 1A. Risk Factors - The Company's hydraulic fracturing and former sand mining operations may result in silica-related health issues and litigation that could have a material adverse effect on the Company" for additional information.

Air emissions. The federal Clean Air Act (the "CAA") and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other compliance requirements. Such laws and regulations could require a facility to obtain pre-approval for construction or modification projects expected to produce new air pollutant emissions or result in the increase of existing air pollutant emissions. Additionally, these legal requirements could impose stringent air permit conditions or utilize specific emission control technologies to limit emissions of certain air pollutants. Federal and state regulatory agencies can also impose administrative, civil and criminal penalties for noncompliance with air permits or other requirements of the CAA and associated state laws and regulations.

See "Item 1A. Risk Factors - The Company's operations are subject to stringent environmental, oil and gas-related and occupational safety and health laws and regulations that could cause it to delay, curtail or cease its operations or expose it to material costs and liabilities" for additional information.

Climate change. Climate change continues to attract considerable public, political and scientific attention. As a result, numerous regulatory initiatives have been proposed, and are likely to continue to be proposed, at the international, national, regional and state levels of government to monitor and limit existing sources of GHG emissions as well as to restrict or eliminate emissions from new sources. These regulatory efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. Additionally, the threat of climate change has resulted in increasing political, litigation and financial risks associated with the production of fossil fuels and emission of GHGs. The adoption and implementation of any federal or state legislation, regulations or executive orders or the occurrence of any litigation or financial developments that impose more stringent requirements or bans on GHG-emitting production activities or locations where such production activities may occur, impose liabilities for past conduct relating to GHG-emitting production activities, or limit or eliminate sources of financing for ongoing production operations could require the Company to incur increased costs, such as compliance or consumption costs, and thereby reduce demand for oil and gas, or otherwise impair the ability of the Company to continue to operate in an economic manner.

See "Item 1A. Risk Factors - The Company's operations are subject to a number of risks arising out of concerns regarding the threat of climate change, including regulatory, political, litigation and financial risks, that could result in increased operating costs and costs of compliance, limit the areas in which oil and gas production may occur, reduce demand for the oil and gas the Company produces, and expose the Company to the risk of increased activism and decreased funding for the industry, while the potential physical effects of climate change could disrupt the Company's production and cause it to incur significant costs in preparing for or responding to those effects" for additional information.

Endangered species. The federal Endangered Species Act (the "ESA") and analogous state laws regulate activities that could have an adverse effect on species listed as threatened or endangered under the ESA. Some of the Company's operations are conducted in areas where protected species or their habitats are known to exist. In these areas, the Company may be obligated to develop and implement plans to avoid potential adverse effects to protected species and their habitats, and the Company may be delayed, restricted or prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when the Company's operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to drilling activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species.

See "Item 1A. Risk Factors - Laws and regulations pertaining to protection of threatened and endangered species or to critical habitat, wetlands and natural resources could delay, restrict or prohibit the Company's operations and cause it to incur substantial costs that may have a material adverse effect on the Company's development and production of reserves" for additional information.

Occupational health and safety. The Company's operations are subject to the requirements of the federal Occupational Safety and Health Act and comparable state statutes. These laws and the implementing regulations issued by OSHA strictly govern the protection of the health and safety of employees. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that the Company organize or disclose information about hazardous materials used or produced in the Company's operations.

OSHA published a final rule in 2016 that established a more stringent permissible exposure to respirable crystalline silica and provides other provisions to protect employees. This final rule required compliance with most applicable requirements by various industry sectors, including the hydraulic fracturing sector, by June 2018, and further requires compliance with engineering control obligations to limit exposures to respirable crystalline silica in connection with hydraulic fracturing activities by June 2021. Respirable silica is a known health hazard for workers exposed over long periods.

See "Item 1A. Risk Factors - The Company's operations are subject to stringent environmental, oil and gas-related and occupational safety and health laws and regulations that could cause it to delay, curtail or cease its operations or expose it to material costs and liabilities" and "Item 1A. Risk Factors - The Company's hydraulic fracturing and former sand mining operations may result in silica-related health issues and litigation that could have a material adverse effect on the Company" for additional information.

Other regulation of the oil and gas industry. The oil and gas industry is regulated by numerous federal, state and local authorities. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous federal and state departments and agencies are authorized by statute to issue rules and regulations that are binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry may increase the Company's cost of doing business by increasing the cost of production, the Company believes that these burdens generally do not affect the Company any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Development and production. Development and production operations are subject to various types of regulation at the federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, the posting of bonds in connection with various types of activities and filing reports concerning operations. Most states, and some counties and municipalities, in which the Company operates also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the method and ability to fracture stimulate wells;
- the surface use and restoration of properties upon which wells are drilled;

- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and gas properties. Some states allow forced pooling or integration of tracts to facilitate development, while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce the Company's interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose requirements regarding production rates. These laws and regulations may limit the amount of oil and gas the Company can produce from the Company's wells or limit the number of wells or the locations that the Company can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, NGL and gas within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but there can be no assurance that they will not do so in the future. The effect of such future regulations may limit the amounts of oil and gas that may be produced from the Company's wells, negatively affect the economics of production from these wells or limit the number of locations the Company can drill.

Regulation of transportation and sale of gas. The availability, terms and cost of transportation significantly affect sales of gas. Federal and state regulations govern the price and terms for access to gas pipeline transportation. Intrastate gas pipeline transportation activities are subject to various state laws and regulations, as well as orders of state regulatory bodies. The interstate transportation and sale of gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission ("FERC"). FERC endeavors to make gas transportation more accessible to gas buyers and sellers on an open-access and non-discriminatory basis.

Pursuant to the Energy Policy Act of 2005 ("EPAct 2005") it is unlawful for any entity, such as the Company, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of gas or transportation services subject to regulation by FERC, in contravention of rules prescribed by FERC. The EPAct 2005 also gives FERC authority to impose civil penalties of up to $1 million per day, subject to annual inflation adjustment, for each violation of the Natural Gas Act ("NGA"), the Natural Gas Policy Act of 1978 and related regulations.

Under FERC Order 704, which regulates annual gas transaction reporting requirements, any market participant, including a producer such as the Company, that engages in wholesale sales or purchases of gas that equal or exceed 2.2 million MMBtus of physical gas in the previous calendar year must annually report such sales and purchases to FERC on Form No. 552 by May 1 of the year following the calendar year when such sales and purchases occurred. Form No. 552 contains aggregate volumes of wholesale gas purchased or sold in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. Order 704 is intended to increase the transparency of the wholesale gas markets and to assist FERC in monitoring those markets and in detecting market manipulation.

Intrastate gas pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate gas pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate gas pipeline rates, vary from state to state. Additional proposals and proceedings that might affect the gas industry are considered from time to time by the U.S. Congress, FERC, state legislatures, state regulatory bodies and the courts. The Company cannot predict when or if any such proposals might become effective or their effect, if any, on its operations. The Company believes that the regulation of intrastate gas pipeline transportation rates will not affect its operations in any way that is materially different from the effects on its similarly situated competitors.

See additional information in "Item 1A. Risk Factors - The Company may not be able to obtain access on commercially reasonable terms or otherwise to pipelines and storage facilities, gathering systems and other transportation, processing, fractionation, refining and export facilities to market its oil, NGL and gas production; the Company relies on a limited number of purchasers for a majority of its products" and "Item 1A. Risk Factors - The Company's transportation of gas, sales and purchases of oil, NGL, gas or other energy commodities, and any derivative activities related to such energy commodities, expose the Company to potential regulatory risks."

Gas processing. The Company's gas processing operations are generally not subject to FERC or state regulation with respect to rates or terms and conditions of service.

See "Item 1A. Risk Factors - The Company's gas processing, gathering and treating operations are subject to operational and regulatory risks, which could result in significant damages and the loss of revenue" for additional information.

Gas gathering. Section 1(b) of the NGA exempts gas gathering facilities from FERC jurisdiction. While the Company owns or operates some gas gathering facilities, the Company also depends on gathering facilities owned and operated by third parties to gather production from its properties, and therefore the Company is affected by the rates charged by these third parties for gathering services. To the extent that changes in federal or state regulation affect the rates charged for gathering services, the Company also may be affected by these changes. The Company does not anticipate that the Company would be affected any differently than similarly situated gas producers.

See "Item 1A. Risk Factors - The Company's gas processing, gathering, and treating operations are subject to operational and regulatory risks, which could result in significant damages and the loss of revenue" and "Item 1A. Risk Factors - The Company may not be able to obtain access on commercially reasonable terms or otherwise to pipelines and storage facilities, gathering systems and other transportation, processing, fractionation, refining and export facilities to market its oil, NGL and gas production; the Company relies on a limited number of purchasers for a majority of its products" for additional information.

Regulation of transportation and sale of oil and NGL. Intrastate liquids pipeline transportation rates, terms and conditions are subject to regulation by numerous federal, state and local authorities and, in a number of instances, the ability to transport and sell such products on interstate pipelines is dependent on pipelines that are also subject to FERC jurisdiction under the Interstate Commerce Act (the "ICA"). The Company does not believe these regulations affect it any differently than other producers.

The ICA requires that pipelines maintain a tariff on file with the FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service on interstate common carrier pipelines be "just and reasonable." Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before the FERC.

Rates of interstate liquids pipelines are currently regulated by the FERC, primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by the FERC. For the five-year period beginning in July 2016, the FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 1.23 percent. This adjustment is subject to review every five years. Under the FERC's regulations, a liquids pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. Increases in liquids transportation rates may result in lower revenue and cash flows for the Company.

In addition, due to common carrier regulatory obligations of liquids pipelines, capacity must be prorated among shippers in an equitable manner in the event there are nominations in excess of capacity by current shippers or capacity requests are received from a new shipper. Therefore, new shippers or increased volumes by existing shippers may reduce the capacity available to the Company. Any prolonged interruption in the operation or curtailment of available capacity of the pipelines that the Company relies upon for liquids transportation could have a material adverse effect on its business, financial condition, results of operations and cash flows. However, the Company believes that access to liquids pipeline transportation services generally will be available to it to the same extent, if not better given the Company's firm transportation contracts, as to its similarly situated competitors.

In November 2009, the Federal Trade Commission (the "FTC") issued regulations pursuant to the Energy Independence and Security Act of 2007 intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to $1 million per violation per day, subject to annual inflation adjustment. The Commodity Futures Trading Commission (the "CFTC") has also issued anti-manipulation rules that subject violators to a civil penalty of up to the greater of $1 million per violation, subject to annual inflation adjustment, or triple the monetary gain to the person for each violation.

See "Items 1A. Risk Factors - The Company's transportation of gas, sales and purchases of oil, NGL, gas or other energy commodities, and any derivative activities related to such energy commodities, expose the Company to potential regulatory risks."

Energy commodity prices. Sales prices of oil, NGL and gas are not currently regulated and sales are made at market prices. Although prices of these energy commodities are currently unregulated, the U.S. Congress historically has been active in their regulation. The Company cannot predict whether new legislation to regulate oil and gas might actually be enacted by the U.S. Congress or the various state legislatures, and what effect, if any, the proposals might have on the Company's operations.

Transportation of hazardous materials. The federal Department of Transportation has adopted regulations requiring that certain entities transporting designated hazardous materials develop plans to address security risks related to the transportation of hazardous materials. The Company does not believe that these requirements will have an adverse effect on the Company or its operations. The Company cannot provide any assurance that the security plans required under these regulations would protect against all security risks and prevent an attack or other incident related to the Company's transportation of hazardous materials.

ITEM 1A. RISK FACTORS

The nature of the business activities conducted by the Company subjects it to certain hazards and risks. The following is a summary of some of the material risks relating to the Company's business activities. Other risks are described in "Item 1. Business — Competition, Markets and Regulations," "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk." These risks are not the only risks facing the Company. The Company's business could also be affected by additional risks and uncertainties not currently known to the Company or that it currently deems to be immaterial. If any of these risks actually occurs, it could materially harm the Company's business, financial condition or results of operations or impair the Company's ability to implement business plans or complete development activities as scheduled. In that case, the market price of the Company's common stock could decline.

The prices of oil, NGL and gas are highly volatile and have declined significantly in recent years. A sustained decline in these commodity prices could materially and adversely affect the Company's business, financial condition and results of operations.

The Company's revenues, profitability, cash flow and future rate of growth are highly dependent on commodity prices. Commodity prices may fluctuate widely in response to relatively minor changes in the supply of and demand for oil, NGL and gas, market uncertainty and a variety of additional factors that are beyond the Company's control, such as:

- domestic and worldwide supply of and demand for oil, NGL and gas;
- worldwide oil, NGL and gas inventory levels, including at Cushing, Oklahoma, the benchmark location for WTI oil prices, and the U.S. Gulf Coast, where the majority of the U.S. refinery capacity exists;
- volatility and trading patterns in the commodity-futures markets;
- the capacity of U.S. and international refiners to utilize U.S. supplies of oil and condensate;
- weather conditions;
- overall domestic and global political and economic conditions, including the imposition of tariffs or trade or other economic sanctions, political instability or armed conflict in oil and gas producing regions;
- global or national health concerns, including the outbreak of pandemic or contagious disease, such as the recent coronavirus, which may reduce demand for oil, NGL and gas because of reduced global or national economic activity;
- actions of OPEC, its members and other state-controlled oil companies relating to oil price and production controls;
- the price and quantity of oil, NGL and LNG imports to and exports from the U.S.;
- technological advances or social attitudes or policies affecting energy consumption and energy supply;
- domestic and foreign governmental regulations, including environmental regulations, climate change regulations and taxation;
- the effect of energy conservation efforts;
- stockholder activism or activities by non-governmental organizations to limit certain sources of capital for the energy sector or restrict the exploration, development and production of oil and gas;
- the proximity, capacity, cost and availability of pipelines and other processing, fractionation, refinery, storage and export facilities; and
- the price, availability and acceptance of alternative fuels.

Commodity prices have historically been, and continue to be, extremely volatile. For example, the Brent oil prices in 2019 ranged from a high of $74.57 to a low of $54.91 per Bbl and the NYMEX gas prices in 2019 ranged from a high of $3.59 to a low of $2.07 per MMBtu.The Company expects this volatility to continue. A further or extended decline in commodity prices could materially and adversely affect the Company's future business, financial condition, results of operations, liquidity or its ability to repurchase shares of common stock, pay dividends or finance planned capital expenditures. The Company makes price assumptions that are used for planning purposes, and a significant portion of the Company's cash outlays, including rent, salaries and noncancellable capital and transportation commitments, are largely fixed in nature. Accordingly, if commodity prices are below the expectations on which these commitments were based, the Company's financial results are likely to be adversely and disproportionately affected because these cash outlays are not variable in the short term and cannot be quickly reduced to respond to unanticipated decreases in commodity prices.

Significant or extended price declines could also materially and adversely affect the amount of oil, NGL and gas that the Company can produce economically, which may result in the Company having to make significant downward adjustments to its estimated proved reserves. A reduction in production could also result in a shortfall in expected cash flows and require the

Company to reduce capital spending or borrow funds to cover any such shortfall. Any of these factors could negatively affect the Company's ability to replace its production and its future rate of growth.

The Company could experience periods of higher costs if commodity prices rise. These increases could reduce the Company's profitability, cash flow and ability to complete development activities as planned.

Historically, the Company's capital and operating costs have risen during periods of increasing oil, NGL and gas prices. These cost increases result from a variety of factors beyond the Company's control, such as increases in the cost of electricity, steel and other raw materials that the Company and its vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased production and ad valorem taxes. Decreased levels of drilling activity in the oil and gas industry have historically led to cost reductions for some drilling equipment, materials and supplies. However, such costs may rise faster than increases in the Company's revenue if commodity prices rise, thereby negatively impacting the Company's profitability, cash flow and ability to complete development activities as scheduled and on budget. This impact may be magnified to the extent that the Company's ability to participate in the commodity price increases is limited by its derivative risk management activities.

Declining general economic, business or industry conditions could have a material adverse effect on the Company's results of operations.

The economies in the United States and certain countries in Europe and Asia have been growing, with resulting improvements in industrial demand and consumer confidence. However, other economies, such as those of certain South American nations, continue to face economic struggles or slowing economic growth. If these conditions worsen, combined with a decline in economic growth in other parts of the world, there could be a significant adverse effect on global financial markets and commodity prices. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. Global or national health concerns, including the outbreak of pandemic or contagious disease, such as the recent coronavirus, may adversely affect the Company by (i) reducing demand for its oil, NGL and gas because of reduced global or national economic activity, (ii) impairing its supply chain (for example, by limiting manufacturing of materials used in operations), and (iii) affecting the health of its workforce, rendering employees unable to work or travel. If the economic climate in the United States or abroad were to deteriorate, demand for petroleum products could diminish or stagnate, which could depress the prices at which the Company could sell its oil, NGLs and gas, affect the ability of the Company's vendors, suppliers and customers to continue operations and ultimately decrease the Company's cash flows and profitability. In addition, reduced worldwide demand for debt and equity securities issued by oil and gas companies may make it more difficult for it to raise capital.

The refining industry may be unable to absorb rising U.S. oil production; in such a case, the resulting surplus could depress prices and restrict the availability of markets, which could materially and adversely affect the Company's results of operations.

Absent an expansion of U.S. refining and export capacity, rising U.S. production of oil could result in a surplus of these products in the U.S., which would likely cause prices for these commodities to fall and markets to constrict. Although U.S. law was changed in 2015 to permit the export of oil, exports may not occur if demand is lacking in foreign markets or the price that can be obtained in foreign markets does not support associated export capacity expansions, transportation and other costs. In such circumstances, the rate of return on the Company's capital projects would decline, possibly to levels that would make execution of the Company's drilling plans uneconomical, and a lack of market for the Company's products could require that the Company shut in some portion of its production. If this were to occur, the Company's production and cash flow could decrease, or could increase less than forecasted, which could have a material adverse effect on the Company's cash flow and profitability.

The Company faces significant competition and some of its competitors have resources in excess of the Company's available resources.

The oil and gas industry is highly competitive. The Company competes with a large number of companies, producers and operators in a number of areas such as:

- seeking to acquire oil and gas properties suitable for exploration or development;
- marketing oil, NGL and gas production; and
- seeking to acquire the equipment, services and expertise, including trained personnel, necessary to identify, evaluate, develop and operate its properties.

Some of the Company's competitors are larger and have substantially greater financial and other resources than the Company, and as such, the Company may be at a competitive disadvantage in the identification, acquisition and development of properties that complement the Company's operations. The Company also faces competition from companies that supply alternative sources of energy, such as wind or solar power. Competition is expected to increase and in certain cases, governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels or technologies. Governments and other parties are also promoting research into new technologies to accelerate the implementation of alternative energy sources.

The Company's operations involve many operational risks, some of which could result in unforeseen interruptions to the Company's operations and substantial losses to the Company for which the Company may not be adequately insured.

The Company's operations, including drilling and completion activities and water distribution, collection and disposal activities, are subject to all the risks incident to the oil and gas development and production business, including:

- blowouts, cratering, explosions and fires;
- adverse weather effects;
- environmental hazards, such as NGL and gas leaks, oil and produced water spills, pipeline and vessel ruptures, encountering naturally occurring radioactive materials ("NORM"), and unauthorized discharges of toxic chemicals, gases, brine, well stimulation and completion fluids or other pollutants onto the surface or into the subsurface environment;
- high costs, shortages or delivery delays of equipment, labor or other services or water and sand for hydraulic fracturing;
- facility or equipment malfunctions, failures or accidents;
- title problems;
- pipe or cement failures or casing collapses;
- uncontrollable flows of oil, gas or water;
- compliance with environmental and other governmental requirements;
- lost or damaged oilfield workover and service tools;
- surface access restrictions;
- unusual or unexpected geological formations or pressure or irregularities in formations;
- terrorism, vandalism and physical, electronic and cybersecurity breaches, and global or national health concerns, including the outbreak of pandemic or contagious disease, such as the recent coronavirus; and
- natural disasters.

The Company's overall exposure to operational risks may increase as its drilling activity expands and as it increases internally-provided well services, water distribution, water collection, disposal or other services. In addition, any of these risks could adversely impact the Company’s service providers and suppliers, causing its supply chains to be interrupted, slowed, or rendered inoperable. Any of these risks could result in substantial losses to the Company due to injury or loss of life, damage to or destruction of wells, production facilities or other property and natural resources, clean-up responsibilities, regulatory investigations and penalties and suspension of operations.

The Company may not be insured or is not fully insured against certain of the risks described above, either because such insurance is not available or because of the high premium costs and deductibles associated with obtaining such insurance. Additionally, the Company relies to a large extent on facilities owned and operated by third-parties, and damage to or destruction of those third-party facilities could adversely affect the ability of the Company to produce, transport and sell its hydrocarbons.

The Company's operations and drilling activity are concentrated in the Permian Basin of West Texas, an area of high industry activity, which may affect its ability to obtain the personnel, equipment, services, resources and facilities access needed to complete its development activities as planned or result in increased costs; such concentration also makes the Company vulnerable to risks associated with operating in a limited geographic area.

The Company's producing properties are geographically concentrated in the Permian Basin of West Texas. Industry activity is high in the Permian Basin and demand for and costs of personnel, equipment, power, services and resources remains high. Any delay or inability to secure the personnel, equipment, power, services and resources could result in oil, NGL and gas production volumes being below the Company's forecasted volumes. In addition, any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on the Company's results of operations, cash flow and profitability.

As a result of this concentration, the Company may be disproportionately exposed to the impact of delays or interruptions of operations or production in this area caused by external factors such as governmental regulation, state politics, market limitations, water or sand shortages or extreme weather related conditions.

The Company's actual production could differ materially from its forecasts.

From time to time, the Company provides forecasts of expected quantities of future oil and gas production and other financial and operating results. These forecasts are based on a number of estimates and assumptions, including that none of the risks associated with the Company's oil and gas operations summarized in this "Item 1A. Risk Factors" occur. Production forecasts, specifically, are based on assumptions such as:

- expectations of production from existing wells and future drilling activity;
- the absence of facility or equipment malfunctions;
- the absence of adverse weather effects;
- expectations of commodity prices, which could experience significant volatility;
- expected well costs; and
- the assumed effects of regulation by governmental agencies, which could make certain drilling activities or production uneconomical.

Should any of these assumptions prove inaccurate, or should the Company's development plans change, actual production could be materially and adversely affected.

Exploration and development drilling involve substantial costs and risks and may not result in commercially productive reserves.

Drilling involves numerous risks, including the risk that no commercially productive oil or gas reservoirs will be encountered. The cost of drilling, completing and operating wells is often uncertain and drilling operations may be curtailed, delayed or canceled, or become costlier, as a result of a variety of factors, including:

- unexpected drilling conditions;
- unexpected pressure or irregularities in formations;
- equipment failures or accidents;
- construction delays;
- fracture stimulation accidents or failures;
- adverse weather conditions;
- restricted access to land for drilling or laying pipelines;
- title defects;
- lack of available gathering, transportation, processing, fractionation, storage, refining or export facilities;
- lack of available capacity on interconnecting transmission pipelines;
- access to, and the cost and availability of, the equipment, services, resources and personnel required to complete the Company's drilling, completion and operating activities; and
- delays imposed by or resulting from compliance with or changes in environmental and other governmental, regulatory or contractual requirements.

The Company's future drilling activities may not be successful and, if unsuccessful, the Company's proved reserves and production would decline, which could have an adverse effect on the Company's future results of operations and financial condition. While all drilling, whether developmental, extension or exploratory, involves these risks, exploratory and extension drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. The Company expects that it will continue to recognize exploration and abandonment expense in 2020.

Part of the Company's strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

The Company's operations involve utilizing some of the latest drilling and completion techniques as developed by it and its service providers. Risks that the Company faces while drilling horizontal wells include, but are not limited to, the following:

- landing the wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that the Company faces while completing wells include, but are not limited to, the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

Drilling in emerging areas is more uncertain than drilling in areas that are more developed and have a longer history of established drilling operations. New discoveries and emerging formations have limited or no production history and, consequently, the Company is more limited in assessing future drilling results in these areas. If the Company's drilling results are worse than anticipated, the return on investment for a particular project may not be as attractive as anticipated and the Company may recognize noncash charges to reduce the carrying value of its unproved properties in those areas.

Multi-well pad drilling may result in volatility in the Company's operating results.

The Company utilizes multi-well pad drilling, and wells drilled on a pad are not placed on production until all wells on the pad are drilled and completed. In addition, problems affecting a single well could adversely affect production from all of the wells on the pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production, or interruptions in ongoing production. These delays or interruptions may cause volatility in the Company's operating results. Further, any delay, reduction or curtailment of the Company's development and producing operations due to operational delays caused by multi-well pad drilling could result in the loss of acreage through lease expiration.

The Company's use of seismic data is subject to interpretation and may not accurately identify the presence of oil and gas, which could materially and adversely affect the results of its drilling operations.

Even when properly used and interpreted, seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. As a result, the Company's drilling activities may not be successful or economic. In addition, the use of advanced technologies, such as 3-D seismic data, requires greater pre-drilling expenditures than traditional drilling strategies, and the Company could incur losses as a result of such expenditures.

The Company's expectations for future drilling activities will be realized over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of such activities.

The Company has identified drilling locations and prospects for future drilling opportunities, including development, exploratory and infill drilling activities. These drilling locations and prospects represent a significant part of the Company's future drilling plans. For example, the Company's proved reserves as of December 31, 2019 include proved undeveloped reserves and proved developed non-producing reserves of 39 MMBbls of oil, 16 MMBbls of NGL and 83 Bcf of gas. The Company's ability to drill and develop these locations depends on a number of factors, including the availability and cost of capital, regulatory approvals, negotiation of agreements with third parties, commodity prices, costs, access to and availability of equipment, services, resources and personnel, and drilling results. There can be no assurance that the Company will drill these locations or that the Company will be able to produce oil or gas reserves from these locations or any other potential drilling locations. Well results vary by formation and geographic area, and the Company generally prioritizes its drilling activities to focus on remaining locations that are believed to offer the highest return. Changes in the laws or regulations on which the Company relies in planning and executing its drilling programs could materially and adversely impact the Company's ability to successfully complete those programs. For example, under current Texas laws and regulations, the Company may receive permits to drill, and may drill and complete, certain horizontal wells that traverse one or more units and/or leases; a change in those laws or regulations could materially and adversely impact the Company's ability to drill those wells. Because of these uncertainties, the Company cannot give any assurance as to the timing of these activities or that they will ultimately result in the realization of proved reserves or meet the Company's expectations for success. As such, the Company's actual drilling activities may materially differ from the Company's current expectations, which could have a material adverse effect on the Company's proved reserves, financial condition and results of operations.

The Company's operations are substantially dependent upon the availability of water and its ability to dispose of produced water gathered from drilling and production activities. Restrictions on the Company's ability to obtain water or dispose of produced water may have a material adverse effect on its financial condition, results of operations and cash flows.

Water is an essential component of the Company's drilling and hydraulic fracturing processes. Limitations or restrictions on the Company's ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact its operations. Severe drought conditions can result in local water districts taking steps to restrict the use of water in their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If the Company is unable to obtain water to use in its operations from local sources, it may need to be obtained from new sources and transported to drilling sites, resulting in increased costs, which could have a material adverse effect on its financial condition, results of operations and cash flows.

In addition, the Company must dispose of the fluids produced from oil and gas production operations, including produced water, which it does directly or through the use of third party vendors. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. One such concern arises from seismic events near underground disposal wells that are used for the disposal by injection of produced water resulting from oil and gas activities. In 2016, the United States Geological Survey identified Texas as being among the states with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. While the agency has seen these rates decrease since that time, concern continues to exist over earthquakes arising from induced seismic activities. In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells to assess any relationship between seismicity and the use of such wells. For example, in Texas, the Texas Railroad Commission has adopted rules governing the permitting or re-permitting of wells used to dispose of produced water and other fluids resulting from the production of oil and gas in order to address these seismic activity concerns within the state. Among other things, these rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the state to modify, suspend or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity.

States may issue orders to temporarily shut down or to curtail the injection depth of existing wells in the vicinity of seismic events. Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by the Company or by commercial disposal well vendors whom the Company may use from time to time to dispose of produced water. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and gas activities utilizing injection wells for produced water disposal. Any one or more of these developments may result in the Company or its vendors having to limit disposal well volumes, disposal rates and pressures or locations, or require the Company or its vendors to shut down or curtail the injection of produced water into disposal wells, which events could have a material adverse effect on the Company's business, financial condition and results of operations.

The Company's gas processing, gathering and treating operations are subject to operational and regulatory risks, which could result in significant damages and the loss of revenue.

As of December 31, 2019, the Company owns interests in 11 gas processing plants, including the related gathering systems. There are significant risks associated with the operation of gas processing plants and the associated gathering systems. Gas and NGLs are volatile and explosive and may include carcinogens. Damage to or improper operation of gas processing plants, gathering systems or treating facilities could result in an explosion or the discharge of toxic gases, which could result in significant damage claims in addition to interrupting a revenue source.

Moreover, while the Company's gas processing and gathering systems generally are not currently subject to FERC or state regulation with respect to rates or terms and conditions of service, there can be no assurance that such processing and gathering operations will continue to be unregulated in the future. Although these facilities may not be directly regulated, other laws and regulations may affect the availability of gas for gathering and processing, such as state regulations regarding production rates and maximum daily production allowable from gas wells, which could impact the Company's business in these areas. Such regulation could result in additional costs and reduced revenues.

The Company may not be able to obtain access on commercially reasonable terms or otherwise to pipelines and storage facilities, gathering systems and other transportation, processing, fractionation, refining and export facilities to market its oil, NGL and gas production; the Company relies on a limited number of purchasers for a majority of its products.

The marketing of oil, NGL and gas production depends in large part on the availability, proximity and capacity of pipelines and storage facilities, gathering systems and other transportation, processing, fractionation, refining and export facilities, as well as the existence of adequate markets. If there were insufficient capacity available on these systems, if these systems were unavailable to the Company or if access to these systems were to become commercially unreasonable, the price offered for the Company's production could be significantly depressed, or the Company could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons while it constructs its own facility or awaits the availability of third party facilities. The Company also relies (and expects to rely in the future) on facilities developed and owned by third parties in order to store, process, transport, fractionate and sell its oil, NGL and gas production. The Company's plans to develop and sell production from its oil and gas reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient transportation, storage or processing, fractionation, refining or export facilities to the Company, especially in areas of planned expansion where such facilities do not currently exist. Additionally, certain of these challenges may be compounded by the high level of industry activity in the Permian Basin.

For example, following Hurricane Harvey in 2017 and Hurricanes Gustav and Ike in 2008, certain Permian Basin gas processors were forced to shut down their plants due to the inability of certain Texas Gulf Coast NGL fractionators to operate. The Company was able to produce its oil wells and vent or flare the associated gas; however, there is no certainty the Company will be able to vent or flare gas in the future due to potential changes in regulations. The amount of oil and gas that can be produced is subject to limitations in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering, transportation, storage, processing, fractionation, refining or export facilities, or lack of capacity at such facilities. The Company has periodically experienced high line pressure at its tank batteries, which has occasionally led to the flaring of gas due to the inability of the gas gathering systems in the areas to support the increased gas production. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, the Company may be provided only limited, if any, notice as to when these circumstances will arise and their duration.

To the extent that the Company enters into transportation contracts with pipelines that are subject to FERC regulation, the Company is subject to FERC requirements related to use of such capacity. Any failure on the Company's part to comply with FERC's regulations and policies or with a FERC-related pipeline's tariff could result in the imposition of civil and criminal penalties.

A limited number of companies purchase a majority of the Company's oil, NGL and gas. The loss of a significant purchaser could have a material adverse effect on the Company's ability to sell its production.

A failure by purchasers of the Company's production to satisfy their obligations to the Company could require the Company to recognize a charge in earnings and have a material adverse effect on the Company's results of operation.

The Company relies on a limited number of purchasers to purchase a majority of its products. To the extent that purchasers of the Company's production rely on access to the credit or equity markets to fund their operations, there is a risk that those purchasers could default in their contractual obligations to the Company if such purchasers were unable to access the credit or equity markets for an extended period of time. If for any reason the Company were to determine that it was probable that some or all of the accounts receivable from any one or more of the purchasers of the Company's production were uncollectible, the Company would recognize a charge in the earnings of that period for the probable loss.

Laws and regulations regarding hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs and additional operating restrictions, delays or cancellations and have a material adverse effect on the Company's production.

Hydraulic fracturing is a common practice that is used to stimulate production of hydrocarbons from tight formations. The Company conducts hydraulic fracturing in its drilling and completion programs. The process involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to stimulate oil and gas production. The process is typically regulated by state oil and gas commissions or similar agencies, but in recent years, several federal agencies have conducted investigations or asserted regulatory authority over certain aspects of the process. For example, in 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances. Additionally, the EPA has asserted regulatory authority pursuant to the SDWA's UIC program over hydraulic fracturing activities involving the use of diesel and has issued guidance covering such activities. Moreover, the EPA has published an Advance Notice of Proposed Rulemaking to collect data on chemicals used in hydraulic fracturing under the Toxic Substances Control Act and has implemented a final rule under the CWA prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly-owned wastewater treatment plants. Also, the federal Bureau of Land Management ("BLM") published a final rule in 2015 that established new or more stringent standards for performing hydraulic fracturing on federal and Indian lands. The BLM rescinded the 2015 rule in late 2017; however, litigation challenging the BLM's decision to rescind the 2015 rule remains pending in federal district court.

From time to time, the U.S. Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the additives used in the hydraulic-fracturing process. In addition, certain states, including Texas where the Company operates, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure, disposal and well-construction requirements on hydraulic-fracturing operations. For example, in April 2019, Colorado passed legislation reforming exploration and production activities by the oil and gas industry in the state including, among other things, revising the mission of the state oil and gas agency from fostering energy development in the state to instead focusing on regulating the industry in a manner that is protective of public health and safety and the environment, as well as authorizing cities and counties to regulate oil and gas operations within their jurisdictions as they do other development. While the Company does not conduct operations in Colorado, passage or enactment of similar legislation in other states in which it does operate could significantly increase the Company’s operating costs and have a significant adverse effect on the Company's ability to conduct operations. States could elect to prohibit hydraulic fracturing or high volume hydraulic fracturing altogether, following the approach taken by the states of Vermont, Maryland and New York. Also, local land use restrictions, such as city ordinances, may be adopted to restrict or prohibit drilling in general or hydraulic fracturing in particular. In Texas, legislation was adopted providing that the regulation of oil and gas operations in Texas is under the exclusive jurisdiction of the state and thus preempts local regulation of those operations. Nonetheless, municipalities and political subdivisions in Texas continue to have the right to enact "commercially reasonable" regulations for surface activities.

Also, the threat of climate change has resulted in increasing political risks in the United States, including climate-related pledges to ban hydraulic fracturing of oil and gas wells being made by certain candidates seeking the office of President of the United States in 2020. Additionally, Senator Bernie Sanders (D-VT), who is one of the presidential candidates that has pledged to ban hydraulic fracturing, introduced Senate Bill 3247 on January 28, 2020 that, if enacted as proposed, would ban hydraulic fracturing nationwide by 2025.

In the event federal, state or local restrictions or bans pertaining to hydraulic fracturing are adopted in areas where the Company is currently conducting operations, or in the future plans to conduct operations, the Company may incur additional costs to comply with such requirements, experience restrictions, delays or cancellations in the pursuit of exploration, development or production activities, and perhaps be limited or precluded in the drilling of wells or in the volume that the Company is ultimately able to produce from its reserves; one or more of which developments could have a material adverse effect on the Company.

The Company's operations are subject to stringent environmental, oil and gas-related and occupational safety and health laws and regulations that could cause it to delay, curtail or cease its operations or expose it to material costs and liabilities.

The Company's operations are subject to stringent federal, state and local laws and regulations governing, among other things, the drilling of wells, rates of production, the size and shape of drilling and spacing units or proration units, the transportation and sale of oil, NGL and gas, and the discharging of materials into the environment and environmental protection. For example, state laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and gas properties. Some states allow forced pooling or integration of tracts to facilitate development, while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce the Company's interest in the unitized properties. In addition, state conservation laws (i) establish maximum rates of production from oil and gas wells, (ii) generally prohibit the venting or flaring of gas and (iii) impose requirements regarding production rates. These laws and regulations may limit the amount of oil and gas the Company can produce from the Company's wells or limit the number of wells or the locations that the Company can drill.

In connection with its operations, the Company must obtain and maintain numerous environmental and oil and gas-related permits, approvals and certificates from various federal, state and local governmental authorities, and may incur substantial costs in doing so. The need to obtain permits has the potential to delay, curtail or cease the development of oil and gas projects. The Company may in the future be charged royalties on gas emissions or required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues. For example, in 2015, the EPA issued a final rule under the CAA lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone from 75 parts per billion to 70 parts per billion under standards to provide protection of public health and welfare. In subsequent years, the EPA has issued area designations with respect to ground-level ozone and final requirements that apply to state, local and tribal air agencies for implementing the 2015 NAAQS for ground-level ozone. State implementation of the revised NAAQS could, among other things, require installation of new emission controls on some of the Company's equipment, resulting in longer permitting timelines, and significantly increase the Company's capital expenditures and operating costs. In another example, the EPA and U.S. Army Corps of Engineers (the "Corps") released a final rule in 2015 outlining federal jurisdictional reach under the CWA over waters of the U.S., including wetlands. In 2017, the EPA and the Corps agreed to reconsider the 2015 rule and, thereafter, on October 22, 2019, the agencies published a final rule, which became effective on December 31, 2019, rescinding the 2015 rule. On January 23, 2020, the two agencies issued a final rule re-defining the Clean Water Act's jurisdiction over waters of the United States, which redefinition is narrower than found in the 2015 rule. Upon being published in the Federal Register and the passage of 60 days thereafter, the January 23, 2020 final rule will become effective, at which point the United States will be covered under a single regulatory scheme as it relates to federal jurisdictional reach over waters of the United States. However, there remains the expectation that the January 23, 2020 final rule also will be legally challenged in federal district court. To the extent that any challenge to the January 23, 2020 final rule is successful and the 2015 rule or a revised rule expands the scope of the Clean Water Act's jurisdiction in areas where the Company conducts operations, the Company could incur (i) delays, restrictions or prohibitions in the issuance of necessary permits, (ii) restrictions or cessations in the development or expansion of projects, or (iii) increases in the Company's capital expenditures and operating expenses by, for example, requiring installation of new emission controls on some of the Company's equipment, any one or more of which developments could have a material adverse effect on the Company's business, financial condition and results of operations.

Additionally, the Company's operations are subject to a number of federal and state laws and regulations, including the federal OSHA and comparable state statutes, whose purpose is to protect the health and safety of employees. Among other things, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in the Company's operations and that this information be provided to employees, state and local government authorities and citizens.

There can be no assurance that existing or future regulations will not result in a delay, curtailment or cessation of production or processing activities, result in a material increase in the costs of production, development, exploration or processing operations or materially and adversely affect the Company's future operations and financial condition. Noncompliance with these laws and regulations may subject the Company to sanctions, including administrative, civil or criminal penalties, remedial cleanups or corrective actions, delays in permitting or performance of projects, natural resource damages and other liabilities. Such laws and regulations may also affect the costs of acquisitions. In addition, these laws and regulations are subject to amendment or replacement in the future with more stringent legal requirements. Further, any delay, reduction or curtailment of the Company's development and producing operations due to these laws and regulations could result in the loss of acreage through lease expiration.

The nature of the Company's assets and production operations may impact the environment or cause environmental contamination, which could result in material liabilities to the Company.

The Company's assets and production operations may give rise to significant environmental costs and liabilities as a result of the Company's handling of petroleum hydrocarbons and wastes, because of air emissions and water discharges related to its operations, and due to past industry operations and waste disposal practices. The Company's oil and gas business involves the generation, handling, treatment, storage, transport and disposal of wastes, hazardous substances and petroleum hydrocarbons and is subject to environmental hazards, such as oil and produced water spills, NGL and gas leaks, pipeline and vessel ruptures and unauthorized discharges of such wastes, substances and hydrocarbons, that could expose the Company to substantial liability due to pollution and other environmental damage. For example, drilling fluids, produced waters and certain other wastes associated with the Company's exploration, development and production of oil or gas are currently excluded under RCRA from the definition of hazardous waste. These wastes are instead regulated under RCRA's less stringent non-hazardous waste provisions. There have been efforts from time to time to remove this exclusion. For example, in response to a federal consent decree issued in 2016, the EPA was required during 2019 to determine whether certain Subtitle D criteria regulations required revision in a manner that could result in oil and gas wastes being regulated as RCRA hazardous waste. In April 2019, the EPA made a determination that such revision of the regulations was unnecessary. Any future loss of the RCRA exclusion could have a material adverse effect on the Company's results of operations and financial position.

The Company currently owns, leases or operates, and in the past has owned, leased or operated, properties that for many years have been used for oil and gas exploration and production activities, and petroleum hydrocarbons, hazardous substances and wastes may have been released on or under such properties, or on or under other locations, including off-site locations, where such substances have been taken for treatment or disposal. These wastes, substances and hydrocarbons may also be released during future operations. In addition, some of the Company's properties have been operated by predecessors or previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons were not under the Company's control. Joint and several strict liabilities may be incurred in connection with such releases of petroleum hydrocarbons, hazardous substances and wastes on, under or from the Company's properties. Private parties, including lessors of properties on which the Company operates and the owners or operators of properties adjacent to the Company's operations and facilities where the Company's petroleum hydrocarbons, hazardous substances or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as seek damages for noncompliance with environmental laws and regulations or for personal injury or damage to property or natural resources. Such properties and the substances disposed or released on or under them may be subject to CERCLA, RCRA and analogous state laws, which could require the Company to remove previously disposed substances, wastes and petroleum hydrocarbons, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination, the costs of which could have a material adverse effect on the Company's business, financial condition and results of operations.

The Company may not be able to recover some or any of these costs from sources of contractual indemnity or insurance, as pollution and similar environmental risks generally are not insurable or fully insurable, either because such insurance is not available or because of the high premium costs and deductibles associated with obtaining such insurance.

The Company's operations are subject to a number of risks arising out of concerns regarding the threat of climate change, including regulatory, political, litigation and financial risks, that could result in increased operating costs and costs of compliance, limit the areas in which oil and gas production may occur, reduce demand for the oil and gas the Company produces, and expose the Company to the risk of increased activism and decreased funding for the industry, while the potential physical effects of climate change could disrupt the Company's production and cause it to incur significant costs in preparing for or responding to those effects.

The threat of climate change continues to attract considerable attention in the United States and in foreign countries. Numerous initiatives have been proposed and are expected to continue to be proposed at the international, national, regional and state levels of government to monitor and limit existing sources of GHG emissions as well as to restrict or eliminate emissions from new sources. As a result, the Company's operations are subject to a series of regulatory, political, litigation and financial risks associated with the production and processing of fossil fuels and emission of GHGs.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, following the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the CAA, the EPA has adopted regulations that, among other things, (i) establish construction and operating permit reviews for GHG emissions from certain large stationary sources, (ii) require the monitoring and annual reporting of GHG emissions from certain petroleum and gas system sources in the United States, (iii) implement CAA emission standards directing the reduction of methane from certain new, modified, or reconstructed facilities in the oil and gas sector, and (iv) together with the DOT, implement GHG emissions limits on vehicles manufactured for operation in the United States. Additionally, various states, groups of states, and other countries have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, there is a non-binding agreement, the United Nations sponsored "Paris Agreement," for nations to limit their GHG emissions through individually-determined reduction goals every five years after 2020, although the United States has announced its withdrawal from such agreement, effective November 4, 2020.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates seeking the office of the President of the United States in 2020. Critical declarations made by one or more candidates running for President include proposals to ban hydraulic fracturing of oil and gas wells and ban new leases for production of minerals on federal properties, including onshore lands and offshore waters. Other actions that could be pursued by presidential candidates may include more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, the reversal of the United States' withdrawal from the Paris Agreement in November 2020 and reinstatement of the ban on oil exports. Litigation risks are also increasing, as a number of cities, local governments or other persons have sought to bring suit against oil and gas exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts.

There are also financial risks for fossil fuel producers as stockholders or bondholders currently invested in fossil-fuel energy companies concerned about the threat of climate change may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. Additionally, investing and lending practices of various investment firms and institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists, proponents of the Paris Agreement, and foreign citizenry concerned about the threat of climate change not to provide funding for fossil fuel producers. For example, there have been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds, to divest of fossil fuel equities and lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

The adoption and implementation of new or more stringent international, federal or state regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and gas sector or otherwise restrict the areas in which this sector may produce oil and gas or generate GHG emissions could result in increased compliance and consumption costs, and thereby reduce demand for the oil and gas the Company produces. Additionally, political, litigation and financial risks could result in the restriction or cancellation of production activities, incurring liability for infrastructure damages as a result of climate changes, or impairing the Company's ability to continue to operate in an economic manner. Finally, if increasing concentrations of GHGs in the Earth's atmosphere were to result in significant physical effects, such as increased frequency and severity of storms, floods, droughts and other extreme climatic events, then such effects could have a material adverse effect on the Company's exploration and production operations.

In addition, companies in the oil and gas industry have been the target of activist efforts from both individuals and non-governmental organizations, including instituting litigation and supporting political or regulatory efforts to, among other things, limit or ban hydraulic fracturing, restrict or ban certain operating practices, including the disposal of waste materials, such as hydraulic fracturing fluids and produced water, deny or delay drilling permits, prohibit the venting or flaring of gas, reduce access of the oil and gas industry to federal and state government lands, and delay or cancel oil and gas developmental or expansion projects. The Company may need to incur significant costs associated with responding to these initiatives, and complying with any resulting additional legal or regulatory requirements could have a material adverse effect on the Company’s business, financial condition, cash flows and results of operations.

Laws and regulations pertaining to protection of threatened and endangered species or to critical habitat, wetlands and natural resources could delay, restrict or prohibit the Company's operations and cause it to incur substantial costs that may have a material adverse effect on the Company's development and production of reserves.

The federal ESA and comparable state laws were established to protect endangered and threatened species. Under the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Federal Migratory Bird Treaty Act. Oil and gas operations in the Company's operating areas may be adversely affected by seasonal or permanent restrictions imposed on drilling activities by the U.S. Fish and Wildlife Services (the "FWS") that are designed to protect various wildlife, which may materially restrict the Company's access to federal or private land use. Permanent restrictions imposed to protect endangered and threatened species could prohibit drilling in certain areas, impact suppliers of critical materials or services, or require the implementation of expensive mitigation measures. Additionally, federal statutes, including the CWA, the OPA and CERCLA, as well as comparable state laws, prohibit certain actions that adversely affect critical habitat, wetlands and natural resources. If harm to species or damages to wetlands, habitat or natural resources occur or may occur, government entities or, at times, private parties may act to prevent oil and gas exploration or development activities or seek damages for harm to species, habitat or natural resources resulting from drilling, construction or releases of petroleum hydrocarbons, wastes, hazardous substances or other regulated materials, and, in some cases, may seek criminal penalties.

Moreover, the FWS may make determinations with respect to the listing of species as endangered or threatened under the ESA, which may result in more fulsome protections for non-protected or lesser-protected species. The designation of previously unprotected species or the re-designation of under protected species as threatened or endangered in areas where the Company conducts operations could cause the Company to incur increased costs arising from species protection measures or could result in delays, restrictions or prohibitions on its development and production activities that could have a material adverse effect on the Company's ability to develop and produce reserves.

Future price declines could result in a reduction in the carrying value of the Company's proved oil and gas properties, which could materially and adversely affect the Company's results of operations.

Significant or extended price declines could result in the Company having to make downward adjustments to the carrying value of its proved oil and gas properties. The Company performs assessments of its oil and gas properties whenever events or circumstances indicate that the carrying values of those assets may not be recoverable. In order to perform these assessments, management uses various observable and unobservable inputs, including management's outlooks for (i) proved reserves and risk-adjusted probable and possible reserves, (ii) commodity prices, (iii) production costs, (iv) capital expenditures and (v) production. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of the Company's oil and gas properties, the carrying value may not be recoverable and therefore an impairment charge would be required to reduce the carrying value of the proved properties to their fair value. For example, during 2018 and 2017, the Company recorded impairment charges of $77 million and $285 million, respectively, attributable to its Raton Basin field in southeast Colorado, primarily due to declines in commodity prices and downward adjustments to the economically recoverable reserves attributable to the asset. The Company may incur impairment charges in the future, which could materially affect the Company's results of operations in the period incurred. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Results of Operations - Impairment of oil and gas properties and other long-lived assets" and Note 4 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

A portion of the Company's total estimated proved reserves at December 31, 2019 were undeveloped, and those proved reserves may not ultimately be developed.

At December 31, 2019, approximately five percent of the Company's total estimated proved reserves were undeveloped. Recovery of undeveloped proved reserves requires significant capital expenditures and successful drilling. The Company's reserve data assumes that the Company can and will make these expenditures and conduct these operations successfully, which assumptions may not prove to be correct. If the Company chooses not to spend the capital to develop these proved undeveloped reserves, or if the Company is not otherwise able to successfully develop these proved undeveloped reserves, the Company will be required to write-off these proved reserves. In addition, under the SEC's rules, because proved undeveloped reserves may be booked only if they relate to wells planned to be drilled within five years of the date of booking, the Company may be required to write-off any proved undeveloped reserves that are not developed within this five-year timeframe. As with all oil and gas leases, the Company's leases require the Company to drill wells that are commercially productive and to maintain the production in paying quantities, and if the Company is unsuccessful in drilling such wells and maintaining such production, the Company could lose its rights under such leases. The Company's future production levels and, therefore, its future cash flow and profitability will be impacted if it does not successfully developing its proved undeveloped leasehold acreage.

Estimates of proved reserves and future net cash flows are not precise. The actual quantities and net cash flows of the Company's proved reserves may prove to be lower than estimated.

Numerous uncertainties exist in estimating quantities of proved reserves and future net cash flows therefrom. The estimates of proved reserves and related future net cash flows set forth in this Report are based on various assumptions, which may ultimately prove to be inaccurate.

Petroleum engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and gas reserves and estimates of future net cash flows depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas;
- the quality and quantity of available data;
- the interpretation of that data;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future commodity prices; and
- assumptions concerning future development costs, operating costs, severance, ad valorem and excise taxes, gathering, processing, transportation and fractionation costs and workover and remedial costs.

Because all proved reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating proved reserves:

- the quantities of oil and gas that are ultimately recovered;
- the production costs incurred to recover the reserves;
- the amount and timing of future development expenditures; and
- future commodity prices.

Furthermore, different reserve engineers may make different estimates of proved reserves and cash flows based on the same available data. The Company's actual production, revenues and expenditures with respect to proved reserves will likely differ from the estimates, and the differences may be material.

As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on average prices preceding the date of the estimate and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- the amount and timing of actual production;
- the level of future capital spending;
- increases or decreases in the supply of or demand for oil, NGL and gas; and
- changes in governmental regulations or taxation.

Standardized Measure is a reporting convention that provides a common basis for comparing oil and gas companies subject to the rules and regulations of the SEC. In general, it requires the use of commodity prices that are based upon a historical 12-month unweighted average, as well as operating and development costs being incurred at the end of the reporting period. Consequently, it may not reflect the prices ordinarily received or that will be received for future oil and gas production because of seasonal price fluctuations or other varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and gas properties. Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. In addition, the ten percent discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company or the oil and gas industry in general. Therefore, the estimates of discounted future net cash flows or Standardized Measure in this Report should not be construed as accurate estimates of the current market value of the Company's proved reserves.

The Company periodically evaluates its unproved oil and gas properties to determine recoverability of its cost and could be required to recognize noncash charges in the earnings of future periods.

At December 31, 2019, the Company carried unproved oil and gas property costs of $584 million. GAAP requires periodic evaluation of these costs on a project-by-project basis. These evaluations are affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of the leases and the contracts and permits appurtenant to such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, the Company will recognize noncash charges in the earnings of future periods.

Because the Company's proved reserves and production decline continually over time, the Company will need to mitigate these declines through drilling and production enhancement initiatives and/or acquisitions.

Producing oil and gas reservoirs are characterized by declining production rates, which vary depending upon reservoir characteristics and other factors. Because the Company's proved reserves and production decline continually over time as those reserves are produced, the Company will need to mitigate these declines through drilling and production enhancement initiatives and/or acquisitions of additional recoverable reserves. There can be no assurance that the Company will be able to develop, exploit, find or acquire sufficient additional reserves to replace its current or future production.

The Company may be unable to make attractive acquisitions and any acquisition it completes is subject to substantial risks that could materially and adversely affect its business.

Acquisitions of oil and gas properties, including acreage trades, have from time to time contributed to the Company's growth. Acquisition opportunities in the oil and gas industry are very competitive, which can increase the cost of, or cause the Company to refrain from, completing acquisitions. The success of any acquisition will depend on a number of factors and involves potential risks, including, among other things:

- the inability to accurately forecast future commodity prices and estimate the costs to develop the acquired reserves, the recoverable volumes of reserves, rates of future production and future net cash flows attainable from the acquired reserves;
- the assumption of unknown liabilities, including environmental liabilities, and losses or costs for which the Company is not indemnified or for which the indemnity the Company receives is inadequate;
- the validity of assumptions about costs, including synergies;
- the effect on the Company's liquidity or financial leverage of using available cash or debt to finance acquisitions;
- the diversion of management's attention from other business concerns; and
- an inability to hire, train or retain qualified personnel to manage and operate the Company's growing business and assets.

All of these factors affect whether an acquisition will ultimately generate cash flows sufficient to provide a suitable return on investment. Even though the Company performs a review of the properties it seeks to acquire that it believes is consistent with industry practices, such reviews are often limited in scope. As a result, among other risks, the Company's initial estimates of reserves may be subject to revision following an acquisition, which may materially and adversely affect the desired benefits of the acquisition.

The Company's ability to complete dispositions of assets, or interests in assets, may be subject to factors beyond its control, and in certain cases the Company may be required to retain liabilities for certain matters.

From time to time, the Company sells an interest in a strategic asset for the purpose of assisting or accelerating the asset's development. In addition, the Company regularly reviews its property base for the purpose of identifying nonstrategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. Various factors could materially affect the ability of the Company to dispose of such interests or nonstrategic assets or complete announced dispositions, including the receipt of approvals of governmental agencies or third parties and the availability of purchasers willing to acquire the interests or purchase the nonstrategic assets on terms and at prices acceptable to the Company.

Sellers typically retain certain liabilities or indemnify buyers for certain pre-closing matters, such as matters of litigation, environmental contingencies, royalty obligations and income taxes. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release the Company from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a divestiture, the Company may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

The Company's transportation of gas, sales and purchases of oil, NGLs and gas or other energy commodities, and any derivative activities related to such energy commodities, expose the Company to potential regulatory risks.

The FERC, the FTC and the CFTC hold statutory authority to monitor certain segments of the physical and futures energy commodities markets relevant to the Company's business. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to the Company's transportation of gas in interstate commerce, physical sales and purchases of oil, NGL, gas or other energy commodities, and any derivative activities related to these energy commodities, the Company is required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Failure to comply with such regulations, as interpreted and enforced, could result in agency actions that could materially and adversely affect the Company's results of operations and financial condition.

The Company's derivative risk management activities could result in financial losses, limit the Company's potential gains or fail to protect the Company from declines in commodity prices; the Company may not enter into derivative arrangements with respect to future volumes if prices are unattractive.

The Company's strategy is to enter into derivative arrangements covering a portion of its oil, NGL and gas production to mitigate the effect of commodity price volatility on the Company's net cash provided by operating activities and its net asset value, support the Company's annual capital budgeting and expenditure plans and reduce commodity price risk associated with certain capital projects. These derivative arrangements are subject to mark-to-market accounting treatment, and the changes in fair market value of the contracts are reported in the Company's statements of operations each quarter, which may result in significant noncash gains or losses.

While intended to reduce the effects of oil, NGL and gas price volatility, the Company's derivative arrangements may limit the Company's potential gains if prices rise over the price established by such arrangements. Conversely, the Company's derivative arrangements may be inadequate to protect the Company from continuing and prolonged declines in the price of oil, NGL or gas. Global commodity prices are volatile. Such volatility challenges the Company's ability to forecast the price of oil, NGL and gas, and, as a result, it may become more difficult for the Company to manage its derivative arrangements. In trying to manage its exposure to commodity price risk, the Company may end up with too many or too few derivatives, depending upon where commodity prices settle relative to the Company's derivative price thresholds and how the Company's oil, NGL and gas volumes and production mix fluctuate relative to expectations when the derivatives were entered.

The Company's derivative arrangements may also expose the Company to risk of financial loss in certain circumstances, including, but not limited to, when:

- production is less than the contracted derivative volumes;
- the counterparty to the derivative contract defaults on its contract obligations;
- there is a change in the expected differential between the underlying price in the derivative contract and actual prices received; or
- a sudden, unexpected event materially impacts oil and/or gas prices.

Failure to protect against declines in commodity prices exposes the Company to reduced liquidity when prices decline. A sustained lower commodity price environment would result in lower realized prices for unprotected volumes and reduce the prices at which the Company could enter into derivative contracts on future volumes. This could make such transactions unattractive, and, as a result, some or all of the Company's production volumes forecasted for 2020 and beyond may not be protected by derivative arrangements. In addition, the Company's derivatives arrangements may not achieve their intended strategic purposes.

The failure by counterparties to the Company's derivative risk management activities to perform their obligations could have a material adverse effect on the Company's results of operations.

The use of derivative risk management transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. The Company is unable to predict changes in a counterparty's creditworthiness or ability to perform. Even if the Company accurately predicts sudden changes, the Company's ability to negate the risk may be limited depending upon market conditions and the contractual terms of the transactions. During periods of declining commodity prices, the Company's derivative receivable positions generally increase, which increases the Company's counterparty credit exposure. If any of the Company's counterparties were to default on its obligations under the Company's derivative arrangements, such a default could have a material adverse effect on the Company's results of operations, could result in a larger percentage of the

Company's future production being subject to commodity price changes and could increase the likelihood that the Company's derivative arrangements may not achieve their intended strategic purposes.

The enactment of derivatives legislation could have a material adverse effect on the Company's ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with its business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") enacted in July 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Company, that participate in that market. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations for its implementation. While many Dodd-Frank Act regulations are already in effect, the rulemaking and implementation process is ongoing, and the ultimate effect of the adopted rules and regulations and any future rules and regulations on the Company's business remain uncertain.

In one of the rulemaking proceedings still pending under the Dodd-Frank Act, the CFTC issued in December 2016, proposed rules imposing position limits for certain futures and options contracts in various commodities (including oil and gas) and for swaps that are their economic equivalents. Under the proposed rules on position limits, certain types of derivative transactions are exempt from these limits, provided that such derivative transactions satisfy the CFTC's requirements for certain enumerated "bona fide" derivative transactions. The CFTC has also adopted final rules regarding aggregation of positions, under which a party that controls the trading of, or owns ten percent or more of the equity interests in, another party will have to aggregate the positions of the controlled or owned party with its own positions for purposes of determining compliance with position limits unless an exemption applies. The CFTC's aggregation rules are now in effect, although CFTC staff has granted relief until August 12, 2022 from various conditions and requirements in the final aggregation rules. These rules may affect both the size of the positions that the Company may hold and the ability or willingness of counterparties to trade with the Company, potentially increasing the costs of transactions. Moreover, such changes could materially reduce the Company's access to derivative opportunities, which could adversely affect revenues or cash flow during periods of low commodity prices. As the new position limit rules are not yet final, the impact of those provisions on the Company is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also will require the Company, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or to take steps to qualify for an exemption to such requirements. Although the Company believes it qualifies for the end-user exception from the mandatory clearing requirements for swaps entered to mitigate its commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that the Company uses. If the Company's swaps do not qualify for the commercial end-user exception, or if the cost of entering into uncleared swaps becomes prohibitive, the Company may be required to clear such transactions. The ultimate effect of these rules and any additional regulations on the Company's business is uncertain.

In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although the Company expects to qualify for the end-user exception from margin requirements for swaps entered into to manage its commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that the Company uses. If any of the Company's swaps do not qualify for the commercial end-user exception, the posting of collateral could reduce its liquidity and cash available for capital expenditures and could reduce its ability to manage commodity price volatility and the volatility in its cash flows.

The full impact of the Dodd-Frank Act and related regulatory requirements upon the Company's business will not be known until the regulations are fully implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks the Company encounters and reduce the Company's ability to monetize or restructure its existing derivative contracts. Further, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. The Company's revenues could therefore be materially and adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices.

The European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent the Company transacts with counterparties in foreign jurisdictions or counterparties with other businesses that subject them to regulations in foreign jurisdictions, the Company may become subject to, or otherwise affected by, such regulations. At this time, the impact of such regulations is not clear.

Regulation by the CFTC and banking regulators of the over-the-counter derivatives market and market participants could cause the Company's contract counterparties, which are generally financial institutions and other market participants, to curtail or cease their derivatives activities. The Company believes that these regulatory trends have contributed to a reduction in liquidity of the over-the-counter derivatives market, which could make it more difficult to engage in derivative transactions covering significant volumes of the Company’s future production, and which could materially and adversely affect the cost and availability of derivatives to the Company. If the Company reduces its use of derivatives as a result of such regulation, the Company's results of operations may become more volatile and its cash flows may be less predictable, which could materially and adversely affect the Company's ability to plan for and fund capital expenditures. Any of these consequences could have a material adverse effect on the Company, its financial condition and its results of operations.

The Company is a party to debt instruments, a credit facility and other financial commitments that may restrict its business and financing activities.

The Company is a borrower under fixed rate senior notes and maintains a credit facility that was undrawn as of December 31, 2019. The terms of the Company's borrowings specify scheduled debt repayments and require the Company to comply with certain associated covenants and restrictions. The Company's ability to comply with the debt repayment terms, associated covenants and restrictions is dependent on, among other things, factors outside the Company's direct control, such as commodity prices and interest rates. In addition, from time to time, the Company enters into arrangements and transactions that can give rise to material off-balance sheet obligations, including firm purchase, transportation and fractionation commitments, gathering, processing and transportation commitments on uncertain volumes of future throughput, commitments to purchase minimum volumes of goods and services, operating lease agreements and drilling commitments. The Company's financial commitments could have important consequences to its business including, but not limited to, the following:

- the incurrence of charges associated with unused commitments if actual activities do not meet the Company's expectations at the time such commitments are entered into;
- increasing its vulnerability to adverse economic and industry conditions;
- limiting its flexibility to plan for, or react to, changes in its business and industry;
- limiting its ability to fund future development activities or engage in future acquisitions; and
- placing it at a competitive disadvantage compared to competitors that have less debt and/or fewer financial commitments.

The Company's ability to obtain additional financing is also affected by the Company's debt credit ratings and competition for available debt financing. A ratings downgrade could materially and adversely impact the Company's ability to access debt markets, increase the borrowing cost under the Company's credit facility and the cost of future debt and potentially require the Company to post letters of credit or other forms of collateral for certain obligations.

The Company's ability to declare and pay dividends and repurchase shares is subject to certain considerations.

Dividends are authorized and determined by the Company's board of directors in its sole discretion. The Company's stock repurchase program has no time limit, may be modified, suspended or terminated at any time by the board of directors, and the repurchase of shares pursuant to the stock repurchase program approved by the board of directors are made from time to time based on management's discretion. Decisions regarding the payment of dividends and the repurchase of shares are subject to a number of considerations, including:

- cash available for distribution or repurchases;
- the Company's results of operations and anticipated future results of operations;
- the Company's financial condition, especially in relation to the anticipated future capital needs;
- the level of cash reserves the Company may establish to fund future capital expenditures;
- the Company's stock price; and
- other factors the board of directors deems relevant.

The Company can provide no assurance that it will continue to pay dividends or authorize share repurchases at the current rate or at all. Any elimination of or downward revision in the Company's dividend payout or stock repurchase program could have a material adverse effect on the market price of the Company's common stock.

The Company's business could be materially and adversely affected by security threats, including cybersecurity threats, and other disruptions.

As an oil and gas producer, the Company faces various security threats, including cybersecurity threats to gain unauthorized access to, or control of, sensitive information or to render data or systems corrupted or unusable; threats to the security of the Company's facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected the Company's operations to increased risks that could have a material adverse effect on the Company's business. In particular, the Company's implementation of various procedures and controls to monitor and mitigate security threats and to increase security for the Company's information, facilities and infrastructure may result in increased capital and operating costs. Costs for insurance may also increase as a result of security threats, and some insurance coverage may become more difficult to obtain, if available at all. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to the Company's operations and could have a material adverse effect on the Company's reputation, financial position, results of operations and cash flows.

Cybersecurity attacks in particular are becoming more sophisticated. The Company relies extensively on information technology systems, including internet sites, computer software, data hosting facilities and other hardware and platforms, some of which are hosted by third parties, to assist in conducting its business. The Company's technologies systems and networks, and those of its business associates may become the target of cybersecurity attacks, including without limitation denial-of-service attacks, malicious software, data privacy breaches by employees, insiders or others with authorized access, cyber or phishing-attacks, ransomware, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems and materially and adversely affect the Company in a variety of ways, including the following:

- unauthorized access to and release of seismic data, reserves information, strategic information or other sensitive or proprietary information, which could have a material adverse effect on the Company's ability to compete for oil and gas resources;
- data corruption, communication interruption or other operational disruptions during drilling activities, which could result in the failure to reach the intended target or a drilling incident;
- data corruption or operational disruptions of production infrastructure, which could result in loss of production or accidental discharges;
- unauthorized access to and release of personal information of royalty owners, employees and vendors, or the data or confidential information of customers, suppliers or other third parties, which could expose the Company to allegations that it did not sufficiently protect that information;
- a cybersecurity attack on a vendor or service provider, which could result in supply chain disruptions and could delay or halt operations;
- a cybersecurity attack on third-party gathering, transportation, processing, fractionation, refining or export facilities, which could delay or prevent the Company from transporting and marketing its production, resulting in a loss of revenues;
- a cybersecurity attack involving commodities exchanges or financial institutions, which could slow or halt commodities trading, thus preventing the Company from marketing its production or engaging in derivative activities, resulting in a loss of revenues;
- a cybersecurity attack on a communications network or power grid, which could cause operational disruptions resulting in the loss of revenues; and
- a cybersecurity attack on the Company's automated and surveillance systems, which could cause a loss in production and potential environmental hazards.

These events could damage the Company's reputation and lead to financial losses from remedial actions, loss of business or potential liability. Additionally, certain cyber incidents, such as surveillance, may remain undetected for an extended period of time.

While the Company has experienced cybersecurity attacks in the past, including attempts to gain unauthorized access to data and systems, inadvertent data privacy breaches by employees and phishing-attacks, the Company has not suffered any material losses as a result of such attacks. However, there is no assurance that the Company will not suffer such losses in the future. As cyber threats continue to evolve, the Company may be required to expend significant additional resources to continue to modify or enhance its protective measures or to investigate and remediate any information security vulnerabilities. Additionally, the continuing and evolving threat of cybersecurity attacks has resulted in evolving legal and compliance matters, including increased regulatory focus on prevention, which could require the Company to expend significant additional resources to meet such requirements.

Provisions of the Company's charter documents and Delaware law may inhibit a takeover, which could limit the price investors might be willing to pay in the future for the Company's common stock.

Provisions in the Company's certificate of incorporation and bylaws may have the effect of delaying or preventing an acquisition of the Company or a merger in which the Company is not the surviving company and may otherwise prevent or slow changes in the Company's board of directors and management. In addition, because the Company is incorporated in Delaware, it is governed by the provisions of Section 203 of the Delaware General Corporation Law. These provisions could discourage an acquisition of the Company or other change in control transactions and thereby negatively affect the price that investors might be willing to pay in the future for the Company's common stock.

The Company periodically evaluates its goodwill for impairment and could be required to recognize noncash charges in the earnings of future periods.

At December 31, 2019, the Company had a carrying value for goodwill of $261 million. Goodwill is assessed for impairment annually during the third quarter and whenever facts or circumstances indicate that the carrying value of the Company's goodwill may be impaired, which may require an estimate of the fair values of the reporting unit's assets and liabilities. Those assessments may be affected by (i) positive or negative reserve adjustments, (ii) results of drilling activities, (iii) management's outlook for commodity prices and costs and expenses, (iv) changes in the Company's market capitalization, (v) changes in the Company's weighted average cost of capital and (vi) changes in income taxes. If the fair value of the reporting unit's net assets is not sufficient to fully support the goodwill balance in the future, the Company will reduce the carrying value of goodwill for the impaired value, with a corresponding noncash charge to earnings in the period in which goodwill is determined to be impaired.

The Company's hydraulic fracturing and former sand mining operations may result in silica-related health issues and litigation that could have a material adverse effect on the Company.

The inhalation of respirable crystalline silica dust is associated with the lung disease silicosis. There is evidence of an association between crystalline silica exposure or silicosis and lung cancer and a possible association with other diseases, including immune system disorders, such as scleroderma. These health risks have been, and may continue to be, a significant issue confronting the commercial sand industry. The actual or perceived health risks of mining, processing and handling sand could materially and adversely affect the Company through the threat of product liability or personal injury lawsuits, recently adopted OSHA silica regulations and increased scrutiny by federal, state and local regulatory authorities.

Pioneer Sands LLC ("Pioneer Sands"), the Company's wholly-owned subsidiary that conducted sand mining operations, is named as a defendant, usually among many defendants, in numerous products liability lawsuits brought by or on behalf of current or former employees of Pioneer Sands or its commercial customers alleging damages caused by silica exposure. As of December 31, 2019, Pioneer Sands was the subject of silica exposure claims from two plaintiffs. Almost all of the claims pending against Pioneer Sands arise out of the alleged use of Pioneer Sands' sand products in foundries or as an abrasive blast media and have been filed in the states of Texas and Georgia, although some cases have been brought in other jurisdictions over the years.

It is possible that Pioneer Sands will have additional silica-related claims filed against it, including claims that allege silica exposure for periods for which there is not insurance coverage. In addition, it is possible that similar claims could be asserted arising out of the Company's other operations, including its hydraulic fracturing operations. Any pending or future claims or inadequacies of insurance coverage or contractual indemnification could have a material adverse effect on the Company's results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Reserve Estimation Procedures and Audits

The information included in this Report about the Company's proved reserves as of December 31, 2019, 2018 and 2017 is based on evaluations prepared by the Company's engineers and audited by Netherland, Sewell & Associates, Inc. ("NSAI"). The Company has no oil and gas reserves from non-traditional sources. Additionally, the Company does not provide optional disclosure of probable or possible reserves.

Reserve estimation procedures. The Company has established internal controls over reserve estimation processes and procedures to support the accurate and timely preparation and disclosure of reserve estimates in accordance with SEC requirements. These controls include oversight of the reserves estimation reporting processes by Pioneer's Corporate Reserves Group ("Corporate Reserves"), and annual external audits of substantial portions of the Company's proved reserves by NSAI.

Corporate Reserves is responsible for the management of the oil and gas proved reserve estimation processes. Corporate Reserves is staffed with reservoir engineers and geoscientists who prepare reserve estimates at the end of each calendar quarter, using reservoir engineering information technology. There is oversight of the reservoir engineers by the Director of Corporate Reserves who is in turn subject to direct oversight by the Company's management committee ("MC"). The Company's MC is comprised of its Chief Executive Officer, Chief Financial Officer and other executive officers. The reserve estimates are prepared by reservoir engineers before being submitted to the Director of Corporate Reserves for further review.

The reserve estimates are summarized in reserve reconciliations that quantify reserve changes since the previous year end as revisions of previous estimates, purchases of minerals-in-place, improved recovery, extensions and discoveries, production and sales of minerals-in-place. All reserve estimates, material assumptions and inputs used in reserve estimates and significant changes in reserve estimates are reviewed for engineering and financial appropriateness and compliance with SEC and GAAP standards by Corporate Reserves, in consultation with the Company's accounting and financial management personnel. Annually, the MC reviews the reserve estimates and any differences with the reserve auditors (for the portion of the reserves audited by NSAI) on a consolidated basis before these estimates are approved. The engineers and geoscientists who participate in the reserve estimation and disclosure process periodically attend training provided by external consultants and through internal Pioneer programs. Additionally, Corporate Reserves has prepared and maintains written policies and guidelines for its staff to reference on reserve estimation and preparation to promote consistency in the preparation of the Company's reserve estimates and compliance with the SEC reserve estimation and reporting rules.

Proved reserves audits. The proved reserve audits performed by NSAI for 2019, 2018 and 2017, in the aggregate, represented 83 percent, 79 percent and 77 percent of the Company's year-end 2019, 2018 and 2017 proved reserves, respectively; and 99 percent, 95 percent and 91 percent of the Company's year-end 2019, 2018 and 2017 associated pre-tax present value of proved reserves discounted at ten percent, respectively.

NSAI follows the general principles set forth in the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information" promulgated by the Society of Petroleum Engineers (the "SPE"). A reserve audit as defined by the SPE is not the same as a financial audit. The SPE's definition of a reserve audit includes the following concepts:

- A reserve audit is an examination of reserve information that is conducted for the purpose of expressing an opinion as to whether such reserve information, in the aggregate, is reasonable and has been presented in conformity with the 2007 SPE publication entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information."

- The estimation of reserves is an imprecise science due to the many unknown geologic and reservoir factors that cannot be estimated through sampling techniques. Since reserves are only estimates, they cannot be audited for the purpose of verifying exactness. Instead, reserve information is audited for the purpose of reviewing in sufficient detail the policies, procedures and methods used by a company in estimating its reserves so that the reserve auditors may express an opinion as to whether, in the aggregate, the reserve information furnished by a company is reasonable.

- The methods and procedures used by a company, and the reserve information furnished by a company, must be reviewed in sufficient detail to permit the reserve auditor, in their professional judgment, to express an opinion as to the reasonableness of the reserve information. The auditing procedures require the reserve auditor to prepare their own estimates of reserve information for the audited properties.

In conjunction with the audit of the Company's proved reserves and associated pre-tax present value discounted at ten percent, Pioneer provided to NSAI its external and internal engineering and geoscience technical data and analyses. Following

NSAI's review of that data, it had the option of honoring Pioneer's interpretations, or making its own interpretations. No data was withheld from NSAI. NSAI accepted without independent verification the accuracy and completeness of the historical information and data furnished by Pioneer with respect to ownership interest, oil and gas production, well test data, commodity prices, operating and development costs, and any agreements relating to current and future operations of the properties and sales of production. However, if in the course of its evaluations something came to its attention that brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data.

In the course of its evaluations, NSAI prepared, for all of the audited properties, its own estimates of the Company's proved reserves and the pre-tax present values of such reserves discounted at ten percent. NSAI reviewed its audit differences with the Company, and, in a number of cases, held meetings with the Company to review additional reserves work performed by the Company's technical teams and any updated performance data related to the proved reserve differences. Such data was incorporated, as appropriate, by both parties into the proved reserve estimates. NSAI's estimates, including any adjustments resulting from additional data, of those proved reserves and the pre-tax present value of such reserves discounted at ten percent did not differ from Pioneer's estimates by more than ten percent in the aggregate. However, when compared on a lease-by-lease, field-by-field or area-by-area basis, some of the Company's estimates were greater than those of the reserve auditors and some were less than the estimates of the reserve auditors. When such differences do not exceed ten percent in the aggregate and NSAI is satisfied that the proved reserves and pre-tax present values of such reserves discounted at ten percent are reasonable and that its audit objectives have been met, NSAI will issue an unqualified audit opinion. Remaining differences are not resolved due to the limited cost benefit of continuing such analyses by the Company and the reserve auditors. At the conclusion of the audit process, it was NSAI's opinion, as set forth in its audit letter, which is included as an exhibit to this Report, that Pioneer's estimates of the Company's proved oil and gas reserves and associated pre-tax present values discounted at ten percent are, in the aggregate, reasonable and have been prepared in accordance with the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information."

Qualifications of proved reserves preparers and auditors. Corporate Reserves is staffed by petroleum engineers with extensive industry experience and is managed by the Director of Corporate Reserves, the technical person who is primarily responsible for overseeing the Company's reserves estimates. These individuals meet the professional qualifications of reserves estimators and reserves auditors as defined by the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information." The qualifications of the Director of Corporate Reserves include 40 years of international and domestic experience as a petroleum engineer, with 22 years focused on reserves reporting for independent oil and gas companies, including Pioneer. He has an additional 18 years of Permian Basin-focused production engineering, advanced reservoir engineering, petrophysics, consulting and special project research experience with major oil companies. His educational background includes an undergraduate degree in Geological Engineering with a Petroleum Engineering emphasis.

NSAI provides worldwide petroleum property analysis services for energy clients, financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. The technical person primarily responsible for auditing the Company's reserves estimates has been a practicing consulting petroleum engineer at NSAI since 1983 and has over 40 years of practical experience in petroleum engineering, including over 37 years of experience in the estimation and evaluation of proved reserves. He graduated with a Bachelor of Science degree in Chemical Engineering in 1978 and meets or exceeds the education, training and experience requirements set forth in the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information."

Technologies used in proved reserves estimates. Proved undeveloped reserves include those reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion. Undeveloped reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of production when drilled, or where reliable technology provides reasonable certainty of economic producibility. Undrilled locations may be classified as having undeveloped proved reserves only if an ability and intent has been established to drill the reserves within five years, unless specific circumstances justify a longer time period.

In the context of reserves estimations, reasonable certainty means a high degree of confidence that the quantities will be recovered and reliable technology means a grouping of one or more technologies (including computational methods) that has been field-tested and has been demonstrated to provide reasonable certainty that the results will be consistent and repeatable in the formation being evaluated or in an analogous formation. In estimating proved reserves, the Company uses several different traditional methods such as performance-based methods, volumetric-based methods and analogy with similar properties. In addition, the Company utilizes additional technical analysis such as seismic interpretation, wireline formation tests, geophysical logs and core data to provide incremental support for more complex reservoirs. Information from this incremental support is combined with the traditional technologies outlined above to enhance the certainty of the Company's proved reserve estimates.

Proved Reserves

Oil and gas proved reserves, located entirely in the United States, are as follows:

	Summary of Oil and Gas Proved Reserves as of Fiscal Year-End Based on Average Fiscal-Year Prices				
	Proved Reserve Volumes				
	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf) (a)	Total (MBOE)	%
As of December 31, 2019:					
Developed	571,293	268,468	1,429,417	1,077,997	95%
Undeveloped	32,457	13,515	70,096	57,655	5%
Total proved reserves	603,750	281,983	1,499,513	1,135,652	100%
As of December 31, 2018:					
Developed	521,579	219,730	1,330,852	963,118	92%
Undeveloped	43,431	21,184	127,722	85,902	8%
Total proved reserves	565,010	240,914	1,458,574	1,049,020	100%
As of December 31, 2017:					
Developed	442,364	189,434	1,629,451	903,373	92%
Undeveloped	40,525	21,063	122,429	81,993	8%
Total proved reserves	482,889	210,497	1,751,880	985,366	100%

(a) Total proved gas reserves include 100,236 MMcf, 106,948 MMcf and 171,623 MMcf of gas the Company expected to be produced and used as field fuel (primarily for compressors) as of December 31, 2019, 2018 and 2017, respectively.

The Company's Standardized Measure of total proved reserves are as follows:

	As of December 31,		
	2019	2018	2017
	(in millions)		
Proved developed reserves	$ 7,588	$ 10,694	$ 7,708
Proved undeveloped reserves	2,146	639	443
	$ 9,734	$ 11,333	$ 8,151

See "Unaudited Supplementary Information" included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Description of Properties

Development drilling activity by significant area is as follows:

	Year Ended December 31, 2019	
	Permian Basin	Total Company
Beginning wells in progress	16	16
Wells spud	15	15
Less:		
Successful wells	26	26
Ending wells in progress	5	5

Exploration/extension drilling activity by significant asset area is as follows:

	Year Ended December 31, 2019	
	Permian Basin	Total Company
Beginning wells in progress	163	166
Wells spud	352	352
Less:		
Successful wells	280	280
Unsuccessful wells	1	1
Wells sold	—	3
Ending wells in progress	234	234

Average daily oil, NGLs, gas and total production by significant asset area are as follows:

	Year Ended December 31, 2019	
	Permian Basin	Total Company
Oil (Bbls)	211,104	212,353
NGL (Bbls)	71,123	72,323
Gas (Mcf) (a)	353,007	365,055
Total (BOE)	341,062	345,518

(a) Gas production excludes gas produced and used as field fuel.

Costs incurred by significant asset area are as follows:

	Year Ended December 31, 2019	
	Permian Basin	Total Company
	(in millions)	
Property acquisition costs:		
Proved	$ 2	$ 2
Unproved	26	26
Exploration costs	2,185	2,190
Development costs	667	667
Asset retirement obligations	85	85
	$ 2,965	$ 2,970

Permian Basin. With approximately 765,000 gross acres (680,000 net acres), Pioneer is the largest acreage holder in the Spraberry/Wolfcamp field, which the U.S. Geological Survey ("USGS") estimates is the largest continuous oil field in the United States. Pioneer's interests in the northern portion of the play comprise approximately 565,000 gross acres and its interests in the southern portion of the play, where the Company has a joint venture with Sinochem, comprise approximately 200,000 gross acres. The oil produced from the Spraberry/Wolfcamp field is West Texas Intermediate Sweet, and the gas produced is casinghead gas with an average energy content of 1,400 Btu. The oil and gas are produced primarily from six formations, the Spraberry, the Jo Mill, the Dean, the Wolfcamp, the Strawn and the Atoka, at depths ranging from 7,500 feet to 14,000 feet. The Company believes that it has significant resource potential within its Spraberry, Jo Mill and Wolfcamp formation acreage, based on its extensive geologic data covering the Middle Spraberry, Jo Mill and Lower Spraberry intervals and the Wolfcamp A, B, C and D intervals and its drilling results to date.

During 2019, the Company successfully completed 229 horizontal wells in the northern portion of the play and 77 horizontal wells in the southern portion of the play. In the northern portion of the play, approximately 45 percent of the horizontal wells placed on production were Wolfcamp A interval wells, approximately 40 percent were Wolfcamp B interval wells and approximately 15 percent were Spraberry and Wolfcamp D interval wells. The majority of the wells placed on production in the southern portion of the play were Wolfcamp B interval wells. In addition, the Company continues to complete acreage trades that allow the Company to drill wells with longer laterals, improving the expected returns of the wells. The Company estimates that the acreage trades completed in 2019 added approximately 4.5 million lateral feet to the Company's drilling inventory.

The Company plans to operate an average of 23 to 24 rigs in the Spraberry/Wolfcamp field in 2020, which includes an average of five rigs operating in the southern portion of the play. During 2020, the Company expects approximately 40 percent of its planned horizontal wells to be drilled in the Wolfcamp B interval, 40 percent in the Wolfcamp A interval and the remaining 20 percent will be a combination of wells in the Spraberry intervals and a limited appraisal program for the Wolfcamp D interval.

Selected Oil and Gas Information

Production, price and cost data. The price that the Company receives for the oil and gas it produces is largely a function of market supply and demand. Demand is affected by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or gas can result in substantial price volatility. Historically, commodity prices have been volatile and the Company expects that volatility to continue in the future. A decline in oil, NGL and gas prices or poor drilling results could have a material adverse effect on the Company's financial position, results of operations, cash flows, quantities of oil and gas reserves that may be economically produced and the Company's ability to access the capital markets.

The following tables set forth production, price and cost data with respect to the Company's properties. These amounts represent the Company's historical results of operations without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred during the respective years. The production amounts will not match the proved reserve volume tables in the "Unaudited Supplementary Information" section included in "Item 8. Financial Statements and Supplementary Data" because field fuel volumes are included in the proved reserve volume tables. Because of normal production declines, increased or decreased drilling activities and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

PIONEER NATURAL RESOURCES COMPANY

PRODUCTION, PRICE AND COST DATA

	Year Ended December 31, 2019	
	Permian Basin	Total Company
Annual sales volumes:		
Oil (MBbls)	77,053	77,509
NGLs (MBbls)	25,960	26,398
Gas (MMcf)	128,848	133,245
Total (MBOE)	124,488	126,114
Average daily sales volumes:		
Oil (Bbls)	211,104	212,353
NGLs (Bbls)	71,123	72,323
Gas (Mcf)	353,007	365,055
Total (BOE)	341,062	345,518
Average prices:		
Oil (per Bbl)	$ 53.77	$ 53.77
NGL (per Bbl)	$ 19.36	$ 19.33
Gas (per Mcf)	$ 1.75	$ 1.79
Revenue (per BOE)	$ 39.13	$ 38.98
Average costs (per BOE):		
Production costs:		
Lease operating	$ 4.52	$ 4.57
Gathering, processing and transportation	2.19	2.24
Net natural gas plant/gathering	(0.60)	(0.59)
Workover	0.72	0.71
Total	$ 6.83	$ 6.93
Production and ad valorem taxes:		
Ad valorem	$ 0.62	$ 0.63
Production	1.76	1.75
Total	$ 2.38	$ 2.38
Depletion expense	$ 12.85	$ 12.78

PIONEER NATURAL RESOURCES COMPANY

PRODUCTION, PRICE AND COST DATA - (continued)

	Year Ended December 31, 2018	
	Permian Basin	Total Company
Annual sales volumes:		
Oil (MBbls)	66,212	69,583
NGLs (MBbls)	19,878	23,280
Gas (MMcf)	102,934	143,588
Total (MBOE)	103,245	116,794
Average daily sales volumes:		
Oil (Bbls)	181,402	190,639
NGLs (Bbls)	54,459	63,780
Gas (Mcf)	282,010	393,391
Total (BOE)	282,862	319,984
Average prices:		
Oil (per Bbl)	$ 57.13	$ 57.36
NGL (per Bbl)	$ 30.32	$ 29.84
Gas (per Mcf)	$ 1.90	$ 2.13
Revenue (per BOE)	$ 44.37	$ 42.73
Average costs (per BOE):		
Production costs:		
Lease operating	$ 4.27	$ 4.29
Gathering, processing and transportation	2.21	2.52
Net natural gas plant/gathering	(0.67)	(0.41)
Workover	1.01	0.92
Total	$ 6.82	$ 7.32
Production and ad valorem taxes:		
Ad valorem	$ 0.59	$ 0.60
Production	1.94	1.83
Total	$ 2.53	$ 2.43
Depletion expense	$ 13.42	$ 12.52

PIONEER NATURAL RESOURCES COMPANY

PRODUCTION, PRICE AND COST DATA - (continued)

	Year Ended December 31, 2017	
	Permian Basin	Total Company
Annual sales volumes:		
Oil (MBbls)	53,889	57,878
NGLs (MBbls)	16,096	20,078
Gas (MMcf)	71,140	128,665
Total (MBOE)	81,842	99,401
Average daily sales volumes:		
Oil (Bbls)	147,641	158,571
NGLs (Bbls)	44,099	55,008
Gas (Mcf)	194,904	352,507
Total (BOE)	224,224	272,330
Average prices:		
Oil (per Bbl)	$ 48.32	$ 48.24
NGL (per Bbl)	$ 18.69	$ 19.31
Gas (per Mcf)	$ 2.45	$ 2.63
Revenue (per BOE)	$ 37.62	$ 35.39
Average costs (per BOE):		
Production costs:		
Lease operating	$ 4.36	$ 4.58
Gathering, processing and transportation	0.19	0.85
Net natural gas plant/gathering	(0.63)	(0.28)
Workover	0.87	0.80
Total	$ 4.79	$ 5.95
Production and ad valorem taxes:		
Ad valorem	$ 0.58	$ 0.57
Production	1.81	1.59
Total	$ 2.39	$ 2.16
Depletion expense	$ 15.34	$ 13.61

Productive wells. Productive wells consist of producing wells and wells capable of production, including oil wells awaiting connection to production facilities, gas wells awaiting pipeline connections to commence deliveries and shut-in wells. One or more completions in the same well bore are counted as one well. Any well in which one of the multiple completions is an oil completion is classified as an oil well.

Productive oil and gas wells attributable to the Company's properties are as follows:

As of December 31, 2019					
Gross Productive Wells			Net Productive Wells		
Oil	Gas	Total	Oil	Gas	Total
6,677	16	6,693	5,952	9	5,961

Developed, undeveloped and royalty leasehold acreage is as follows:

As of December 31, 2019				
Developed Acreage		Undeveloped Acreage		
Gross Acres	Net Acres	Gross Acres	Net Acres	Royalty Acreage
751,929	667,237	30,467	24,761	98,090

The expiration dates of the leases attributable to gross and net undeveloped acres are as follows:

	As of December 31, 2019	
	Acres Expiring (a)	
	Gross	Net
2020	17,887	15,484
2021	1,667	812
2022	3,537	2,108
2023	445	445
2024	—	—
Thereafter	6,931	5,912
	30,467	24,761

(a) Acres expiring are based on contractual lease maturities.

Of the 16,296 net acres expiring in 2020 and 2021, 16,135 net acres are concentrated in the Permian Basin in West Texas, where the Company has an active drilling program and ongoing efforts to extend leases that may not be drilled prior to expiration. Approximately 13,000 of the net acres expiring in 2020 are subject to continuous drilling obligations, which the Company expects to meet with its active drilling program. The Company currently has no proved undeveloped reserve locations scheduled to be drilled after lease expiration. The remaining 161 net acres expiring in 2020 and 2021 are concentrated in eastern Colorado. The Company has no drilling plans for this acreage and does not have any undeveloped acreage costs recorded as of December 31, 2019 associated with this acreage.

Drilling activities. The following table sets forth the number of gross and net wells drilled by the Company that were productive or dry holes. This information should not be considered indicative of future performance, nor should it be assumed that there was any correlation between the number of productive wells drilled and the oil and gas reserves generated thereby or the costs to the Company of productive wells compared to the costs of dry holes.

	Gross Wells			Net Wells		
	Year Ended December 31,			Year Ended December 31,		
	2019	2018	2017	2019	2018	2017
Productive wells:						
Development	26	35	26	20	23	20
Exploratory	280	251	222	249	226	198
Dry holes:						
Development	—	1	—	—	1	—
Exploratory	1	10	2	1	6	1
	307	297	250	270	256	219
Success ratio (a)	100%	96%	99%	100%	97%	99%

(a) Represents the ratio of those wells that were successfully completed as producing wells or wells capable of producing to total wells drilled and evaluated.

Wells in process of being drilled are as follows:

	As of December 31, 2019	
	Gross Wells	Net Wells
Development	5	5
Exploratory	234	209
	239	214

ITEM 3. LEGAL PROCEEDINGS

The Company is party to various proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to these proceedings and claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. See Note 11 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

The following table sets forth certain information as of the date of this Report regarding the Company's executive officers. All of the Company's executive officers serve at the discretion of the Company's board of directors. There are no family relationships among any of the Company's directors or executive officers.

Name	Position	Age
Scott D. Sheffield	President and Chief Executive Officer	67
Mark S. Berg	Executive Vice President, Corporate Operations	61
Chris J. Cheatwood	Executive Vice President, Field Development and Emerging Technology	59
Richard P. Dealy	Executive Vice President and Chief Financial Officer	53
J.D. Hall	Executive Vice President, Operations	54
Mark H. Kleinman	Executive Vice President and General Counsel	58
William F. Hannes	Senior Vice President, Special Projects	60
Bonnie S. Black	Vice President, Drilling	48
Craig A. Kuiper	Vice President, Production Operations	43
Elizabeth A. McDonald	Vice President, Permian Strategic Planning and Field Development	41
Margaret M. Montemayor	Vice President and Chief Accounting Officer	42
Christopher M. Paulsen	Vice President, Business Development	43
Neal H. Shah	Vice President, Investor Relations	49
Stephanie D. Stewart	Vice President and Chief Information Officer	51
Tyson L. Taylor	Vice President, Human Resources	41

Scott D. Sheffield

Mr. Sheffield was appointed as the Company's President and Chief Executive Officer in February 2019. Previously, he had served as Chief Executive Officer of the Company from 1997 through December 31, 2016, and then as the Executive Chairman until December 31, 2017. He has served as a director of the Company since 1997 and had served as Chairman of the Board from 1999 through February 2019. Mr. Sheffield was the Chairman of the Board of Directors and Chief Executive Officer of Parker & Parsley Petroleum Company, a predecessor of the Company (together with its predecessor companies, "Parker & Parsley"), from January 1989 until the Company was formed in August 1997. Mr. Sheffield joined Parker & Parsley as a petroleum engineer in 1979, was promoted to Vice President - Engineering in September 1981, was elected President and a Director in April 1985, and became Parker & Parsley's Chairman of the Board and Chief Executive Officer on January 19, 1989. Before joining Parker & Parsley, Mr. Sheffield was employed as a production and reservoir engineer for Amoco Production Company. Mr. Sheffield is also a director of The Williams Companies, Inc. Mr. Sheffield is a distinguished graduate of the University of Texas with a Bachelor of Science degree in Petroleum Engineering.

Mark S. Berg

Mr. Berg joined the Company as Executive Vice President and General Counsel in April 2005, serving in those capacities until January 2014, at which time he assumed broader executive responsibilities, most recently being elected to serve as Executive Vice President, Corporate Operations, in April 2019. Prior to joining the Company, Mr. Berg served as Executive Vice President, General Counsel and Secretary of American General Corporation, a Fortune 200 diversified financial services company, from 1997 through 2002. Subsequent to the sale of American General to American International Group, Inc., Mr. Berg joined Hanover Compressor Company as Senior Vice President, General Counsel and Secretary. He served in that capacity from May 2002 through April 2004. Mr. Berg began his career in 1983 with the Houston-based law firm of Vinson & Elkins L.L.P. He was a partner with the firm from 1990 through 1997. Mr. Berg is also a director of ProPetro Holding Corp. and HighPoint Resources Corporation and a director and Vice Chairman of Permian Strategic Partnership Inc. Mr. Berg graduated Magna Cum Laude and Phi Beta Kappa with a Bachelor of Arts degree from Tulane University in 1980. He earned his Juris Doctorate with honors from the University of Texas School of Law in 1983.

Chris J. Cheatwood

Mr. Cheatwood was elected as the Company's Executive Vice President, Field Development and Emerging Technology, in April 2019. Mr. Cheatwood had previously served as Executive Vice President and Chief Technology Officer since May 2017, and as Executive Vice President, Business Development and Geoscience since, from November 2011 to May 2017, Executive Vice President, Business Development and Technology, from February 2010 until November 2011, Executive Vice President, Geoscience from November 2007 until February 2010, Executive Vice President - Worldwide Exploration from

January 2002 until November 2007, Senior Vice President - Worldwide Exploration from December 2000 to January 2002 and Vice President - Domestic Exploration from July 1998 to December 2000. Before joining the Company, Mr. Cheatwood spent ten years with Exxon Corporation. Mr. Cheatwood is a graduate of the University of Oklahoma with a Bachelor of Science degree in Geology and earned his Master of Science degree in Geology from the University of Tulsa.

Richard P. Dealy

Mr. Dealy was elected as the Company's Executive Vice President and Chief Financial Officer in November 2004. Mr. Dealy held positions for the Company as Vice President and Chief Accounting Officer from February 1998 to November 2004 and Vice President and Controller from August 1997 to January 1998. Mr. Dealy joined Parker & Parsley in July 1992 and was promoted to Vice President and Controller in 1996, in which position he served until August 1997. Before joining Parker & Parsley, Mr. Dealy was employed by KPMG LLP. Mr. Dealy graduated with honors from Eastern New Mexico University with a Bachelor of Business Administration degree in Accounting and Finance and is a Certified Public Accountant.

J. D. Hall

Mr. Hall was elected as the Company's Executive Vice President, Operations, in April 2019. Mr. Hall had previously held positions for the Company as Executive Vice President, Permian Operations, from August 2015 to April 2019, Executive Vice President, Southern Wolfcamp Operations from August 2014 to August 2015, Senior Vice President, South Texas Operations from June 2013 to August 2014, Vice President, South Texas Operations from February 2013 to June 2013, Vice President, South Texas Asset Team from September 2012 to February 2013 and Vice President, Eagle Ford Asset Team from January 2010 to September 2012. Prior to his positions in South Texas, he was the Operations Manager in Alaska from January 2005 to January 2010. He previously held several other positions with the Company, including managing offshore, onshore and international projects. He began his career with a predecessor company, MESA, Inc. ("MESA"), in 1989. He has a Bachelor of Science degree in Mechanical Engineering from Texas Tech University and is a Registered Professional Engineer in Texas.

Mark H. Kleinman

Mr. Kleinman was elected as the Company's Executive Vice President and General Counsel in April 2019. He also held the positions of Senior Vice President and General Counsel from January 2014 through April 2019, Vice President from May 2006 until January 2014, Corporate Secretary from June 2005 through August 2015, and Chief Compliance Officer from June 2005 until May 2013. Mr. Kleinman earned a Bachelor of Arts degree in Government from the University of Texas and graduated, with honors, from the University of Texas School of Law.

William F. Hannes

Mr. Hannes was elected as the Company's Senior Vice President, Special Projects in January 2017. Mr. Hannes had previously served the Company as Senior Vice President, Special Management Committee Advisor since August 2014, Executive Vice President, Southern Wolfcamp Operations from February 2013 until August 2014, Executive Vice President, South Texas Operations from February 2010 until February 2013, Executive Vice President, Business Development from December 2007 until February 2010, Executive Vice President, Worldwide Business Development from November 2005 until December 2007 and Vice President, Engineering and Development from September 2003 until November 2005. Mr. Hannes joined Parker & Parsley in July 1997 as Director of Business Development, and continued to serve the Company in this capacity after the Company's formation in August 1997 until he was promoted to Vice President - Engineering and Development in June 2001, which position he held until November 2005. Prior to joining Parker & Parsley, Mr. Hannes held engineering positions with Mobil Corporation and Superior Oil Company. Mr. Hannes earned his Bachelor of Science degree in Petroleum Engineering from Texas A&M University.

Bonnie S. Black

Ms. Black was elected as the Company’s Vice President, Drilling, in May 2019. Ms. Black had previously held positions for the Company as Vice President, Permian Well Planning and Permitting, from September 2015 to June 2019, Vice President, Environmental and Sustainable Development, from January 2015 to September 2015, and Vice President, Environmental, from September 2013 to January 2015. She joined the Company in 2007 and has served in a number of positions, including managing Health, Safety and Environmental for the Company’s Alaska asset. Prior to joining the Company, Ms. Black was a business owner and industry consultant in Alaska, working for several major oil companies. She earned a Bachelor of Science, Civil Engineering degree from Texas A&M University in 1994 and is a registered professional engineer with a specialization in Environmental Engineering.

Craig A. Kuiper

Mr. Kuiper was elected as the Company's Vice President, Production Operations in April 2019. Mr. Kuiper had previously held positions for the Company as Vice President, Permian Operations, from August 2014 to April 2019, and Vice President, Operations, Southern Wolfcamp Asset Team, from February 2013 to September 2014. He joined the Company in 2001 as a production engineer drilling vertical wells, and has held a number of positions, including leading operations and reservoir engineering in Southern Louisiana, the Gulf of Mexico, South Texas, West Panhandle and the Permian Basin. Mr. Kuiper earned a Bachelor of Science, Mechanical Engineering degree from Texas A&M University.

Elizabeth A. McDonald

Ms. McDonald was elected as the Company's Vice President, Permian Strategic Planning and Field Development, in May 2019. Ms. McDonald had previously held positions for the Company as Vice President, Permian Infrastructure Development and Operations, from April 2018 to April 2019, Vice President, South Texas Asset Team, from March 2017 to April 2018, and Vice President, South Texas Subsurface, from August 2014 to February 2017. She joined the Company in 2005 as a reservoir engineer on the Engineering and Development team focused on the Gulf of Mexico and North Africa exploration projects, and has held a number of positions, including as Senior Reservoir Engineering Manager – South Texas Asset Team, Manager of Planning – Corporate Finance, Business Analyst – Worldwide Operations, Senior Reservoir Engineer – Central Gulf Coast Exploration and Reservoir Engineer – Engineering and Development. Ms. McDonald earned a Bachelor of Science, Petroleum Engineering degree in 2001 from Texas A&M University and is a registered professional engineer in Texas.

Margaret M. Montemayor

Ms. Montemayor was elected as the Company's Vice President and Chief Accounting Officer in March 2014. Ms. Montemayor had previously served the Company as Vice President and Corporate Controller since January 2014, Corporate Controller from April 2012 to December 2013 and Director of Technical Accounting and Financial Reporting from June 2010 to March 2012. Prior to joining the Company, Ms. Montemayor served as a Manager at PricewaterhouseCoopers LLP since June 2006. Ms. Montemayor graduated from St. Mary's University in San Antonio, Texas with a Bachelor of Business Administration degree in Accounting and a Master of Business Administration degree and is a Certified Public Accountant.

Christopher M. Paulsen

Mr. Paulsen was elected as the Company's Vice President, Business Development in April 2019. Mr. Paulsen had previously held positions for the Company as Vice President, Marketing, from February 2019 to April 2019, and Vice President, Business Development, from January 2013 to February 2019. He joined the Company in 2002 and has served in a number of positions, including Director - Business Development, Subsurface Manager – Barnett Shale, Manager of Budgeting, Planning and Financial Analysis – Western Division, Manager of Finance – Worldwide Business Development, and Manager of Investor Relations. Mr. Paulsen earned a Business Administration degree in 1999 from Baylor University and a Master of Business Administration degree in 2008 from the University of Texas.

Neal H. Shah

Mr. Shah joined the Company in June 2017 as Vice President, Investor Relations. Before joining the Company, Mr. Shah served as Senior Equity Research Analyst at Thrivent Asset Management from June 2016 to June 2017, and as Vice President at Nuveen LLC from March 2006 to June 2016. He has a financial and equity research background and has held various financial analysis positions at Piper Jaffray & Company, RBC Capital Markets and Goldman Sachs & Company. Mr. Shah earned a Bachelor of Science degree in Electrical Engineering from Louisiana State University and a Master of Business Administration degree from the Booth School of Business at the University of Chicago, where he was a Siebel Scholar and a recipient of the Irwin J. Biedrman Leadership award.

Stephanie D. Stewart

Ms. Stewart was elected as the Company's Vice President and Chief Information Officer in June 2017. Before joining the Company, she served as Vice President of E&P Data and Analytics at the end of her 12-year tenure at Devon Energy. Prior to Devon Energy, she worked in information technology at Williams Energy and BP Amoco. Ms. Stewart earned a Bachelor of Business Administration degree from the University of Oklahoma and her Executive Master of Business Administration degree in Energy from the University of Oklahoma's Price College of Business.

Tyson L. Taylor

Ms. Taylor was elected as the Company's Vice President, Human Resources, in April 2019, and previously served as Vice President, Learning and Development from June 2017 to April 2019. She joined the Company in 2007 and has served in a number of positions, including Director, Organizational Development & Recruiting, Director, Employee Relations & Recruiting, and Manager, Employee Relations & Recruiting. Ms. Taylor earned a Bachelor of Business Administration degree from the University of North Texas in 2001 and a Master of Business Administration degree in 2012 from Southern Methodist University.

Officers are generally elected by the Company's board of directors at its meeting on the day of each annual election of directors, with each such officer serving until a successor has been elected and qualified.

PART II

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

The Company's common stock is listed and traded on the NYSE under the symbol "PXD." The Company's board of directors has authority to declare dividends to the holders of the Company's common stock. The board of directors intends to continue the payment of dividends to the holders of the Company's common stock in the future. The declaration and payment of future dividends, however, will be at the discretion of the board of directors and will depend on, among other things, the Company's earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that the board of directors deems relevant.

As of February 18, 2020, the Company's common stock was held by 9,391 holders of record.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Purchases of the Company's common stock are as follows:

	Three Months Ended December 31, 2019			
Period	**Total Number of Shares Purchased (a)**	**Average Price Paid per Share**	**Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**	**Approximate Dollar Amount of Shares that May Yet Be Purchased under Plans or Programs (b)**
October 2019	1,842	$ 131.75	—	$ 1,272,379,289
November 2019	23,880	$ 133.41	—	$ 1,272,379,289
December 2019	165,537	$ 132.25	164,192	$ 1,250,690,958
	191,259		164,192	

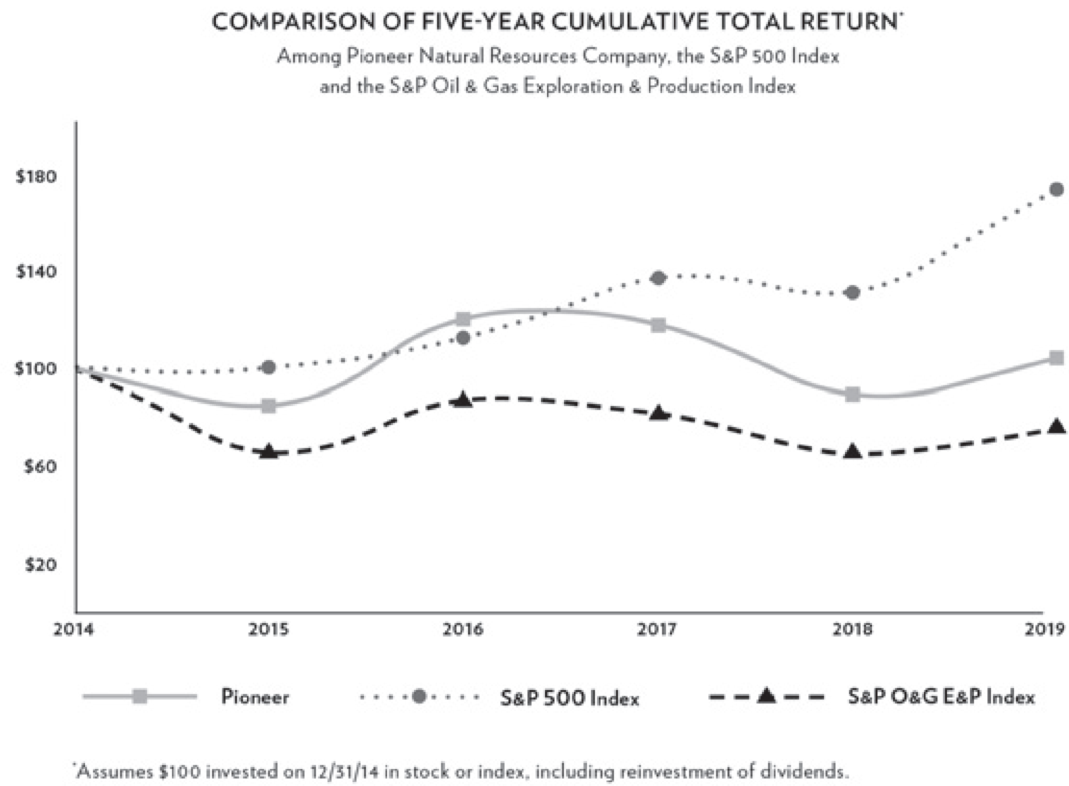
(a) Includes shares purchased from employees in order for employees to satisfy income tax withholding payments related to share-based awards that vested during the period.

(b) In December 2018, the Company's board of directors authorized a $2 billion common stock repurchase program.

Performance Graph

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall the information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

The graph below compares the cumulative total stockholder return on the Company's common stock during the five-year period ended December 31, 2019, with cumulative total returns during the same period for the Standard & Poor's ("S&P") 500 Index and the S&P Oil and Gas Exploration & Production Index.



	As of December 31,					
	2014	2015	2016	2017	2018	2019
Pioneer Natural Resources Company	$100.00	$ 84.28	$121.11	$116.31	$ 88.66	$102.91
S&P 500	$100.00	$101.38	$113.51	$138.29	$132.23	$173.86
S&P Oil & Gas Exploration & Production	$100.00	$ 65.85	$ 87.48	$ 81.96	$ 65.98	$ 73.91

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

ITEM 6. SELECTED FINANCIAL DATA

The Company's selected consolidated financial data as of and for each of the five years ended December 31, 2019 should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data."

	Year Ended December 31,				
	2019	2018	2017	2016	2015
	(in millions, except per share data)				
Statements of Operations Data:					
Oil and gas revenues	$ 4,916	$ 4,991	$ 3,518	$ 2,418	$ 2,178
Sales of purchased oil and gas (a)	$ 4,755	$ 4,388	$ 1,776	$ 1,091	$ 700
Gain (loss) on disposition of assets, net (b)	$ (477)	$ 290	$ 208	$ 2	$ 782
Total revenues and other income	$ 9,304	$ 9,415	$ 5,455	$ 3,382	$ 4,561
Purchased oil and gas (a)	$ 4,472	$ 3,930	$ 1,807	$ 1,155	$ 739
Total costs and expenses (c)	$ 8,317	$ 8,164	$ 5,146	$ 4,341	$ 4,982
Net income (loss) attributable to common stockholders	$ 756	$ 978	$ 833	$ (556)	$ (273)
Net income (loss) per share attributable to common stockholders					
Basic	$ 4.50	$ 5.71	$ 4.86	$ (3.34)	$ (1.83)
Diluted	$ 4.50	$ 5.70	$ 4.85	$ (3.34)	$ (1.83)
Dividends declared per share	$ 1.20	$ 0.32	$ 0.08	$ 0.08	$ 0.08
Balance Sheet Data (as of December 31):					
Total assets	$ 19,067	$ 17,903	$ 17,003	$ 16,459	$ 15,154
Long-term obligations	$ 4,452	$ 3,974	$ 3,596	$ 4,482	$ 5,317
Total equity	$ 12,119	$ 12,111	$ 11,279	$ 10,411	$ 8,375

(a) The Company enters into purchase transactions with third parties and separate sale transactions with third parties to diversify a portion of the Company's oil and gas sales to the Gulf Coast refineries and LNG facilities, international export markets and to satisfy unused gas pipeline capacity commitments. The net balance of these transactions results in either a cash uplift or cash detriment, primarily due to commodity price volatility, associated with the purchase and sale price of each transaction.

(b) See Note 3 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

(c) The Company recorded unusual items in total costs and expenses as follows:

   i. 2019: $329 million related primarily to corporate restructuring charges, asset divestiture-related charges, sand mine decommissioning-related charges and move-related costs to relocate the Company's corporate headquarters. See Note 3 and Note 16 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

   ii. 2018: $77 million of noncash impairment charges related to the Company's gas field assets in the Raton Basin; $443 million of accelerated depreciation associated with the decommissioning of its sand mine assets in 2019; and $39 million of employee-related charges and $124 million of contract termination charges associated with the Company's asset divestitures.

   iii. 2017: $285 million of noncash impairment charges related to gas field assets in the Raton Basin.

   iv. 2016: $32 million of noncash impairment charges related to oil and gas properties in the West Panhandle gas and liquids field.

   v. 2015: $1.1 billion of noncash impairment charges related to oil and gas properties in the West Panhandle gas and liquids field and West Eagle Ford Shale gas and liquids field.

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

Financial and Operating Performance

Pioneer's financial and operating performance for 2019 included the following highlights:

- Net income attributable to common stockholders was $756 million ($4.50 per diluted share) for the year ended December 31, 2019, as compared to net income of $978 million ($5.70 per diluted share) in 2018. The primary components of the $222 million decrease in earnings attributable to common stockholders include:
    - a $767 million decrease in the gain (loss) on disposition of assets (from a net gain on disposition of assets in 2018 to a net loss on disposition of assets in 2019), primarily due to the 2019 net loss recorded on the divestiture of the Company's Eagle Ford assets and other remaining South Texas assets, as compared to the net gain recorded on the Company's 2018 divestitures, including the Company's pressure pumping assets; Sinor Nest (Lower Wilcox) oil field assets; West Panhandle and West Eagle Ford Shale gas and liquids fields assets; and Raton Basin gas field assets;
    - a $177 million increase in DD&A expense, primarily due to an increase in sales volumes due to the Company's successful Spraberry/Wolfcamp horizontal drilling program;
    - a $175 million decrease in net sales of purchased oil and gas due to a decrease in downstream oil margins on the Company's Gulf Coast refinery and export sales;
    - a $75 million decrease in oil and gas revenues, primarily due to a nine percent decrease in average realized commodity prices per BOE, partially offset by an eight percent increase in sales volumes; and
    - a $34 million increase in total oil and gas production costs and production and ad valorem taxes, primarily due to the aforementioned increase in sales volumes.

    Partially offset by:

    - a $401 million decrease in other expense, primarily related to $159 million of 2019 restructuring charges associated with the Company's corporate restructuring program to align its cost structure with the needs of a Permian Basin-focused company (the "Corporate Restructuring Program"), as compared to 2018 expenses that included a noncash charge of $443 million associated with the Company's closure of its Brady, Texas sand mine and $170 million of asset divestiture-related charges associated with the sale of the aforementioned pressure pumping assets and oil and gas properties;
    - a $326 million increase in derivative gain (loss) (from a net loss on derivatives assets in 2018 to a net gain on derivatives in 2019), primarily due to changes in forward commodity prices and the cash settlement of derivative positions in accordance with their terms;
    - a $77 million decrease in impairment charges reflecting the 2018 noncash impairment charge to reduce the carrying value of the Company's divested Raton Basin gas field assets;
    - a $57 million decrease in general and administrative expense due to a reduction in headcount as a result of the Company's Corporate Restructuring Program and other cost saving initiatives;
    - a $56 million decrease in exploration and abandonments expense, primarily due to reductions in geologic and geophysical costs as a result of the aforementioned Corporate Restructuring Program and a reduction in unsuccessful exploratory well costs;
    - a $45 million decrease in income tax expense due to the decrease in earnings in 2019 compared to 2018; and
    - a $38 million increase in interest and other income, primarily related to net proceeds received from the sale of the Company's investment in its new corporate headquarters, partially offset by valuation adjustments associated with the Company's investment in an affiliate and contingent consideration received in the sale of the Company's Eagle Ford assets and other remaining South Texas assets in 2019.
- During 2019, average daily sales volumes increased on a BOE basis by eight percent to 345518 BOEPD, as compared to 319984 BOEPD during 2018, primarily due to the Company's successful Spraberry/Wolfcamp horizontal drilling program, which more than offset the loss of production associated with the Company's 2019 and 2018 divestitures.
- Average oil and NGL prices per Bbl decreased in 2019 to $53.77 and $19.33, respectively, as compared to $57.36 and $29.84, respectively, in 2018. Average gas prices decreased per Mcf in 2019 to $1.79 as compared to $2.13 in 2018.

First Quarter 2020 Outlook

Based on current estimates, the Company expects the following operating and financial results for the first quarter of 2020:

	Three Months Ending March 31, 2020
	Guidance
	($ in millions, except per BOE amounts)
Average daily production (MBOE)	361 - 376
Average daily oil production (MBbls)	217 - 227
Production costs per BOE	$8.25 - $10.25
DD&A per BOE	$12.50 - $14.50
Exploration and abandonments expense	$10 - $20
General and administrative expense	$72 - $82
Accretion of discount on asset retirement obligations	$2 - $5
Interest expense	$30 - $35
Other expense	$20 - $30
Cash flow impact from firm transportation	($50) - $0
Current income tax provision (benefit)	<$5
Effective tax rate	21% - 25%

2020 Capital Budget

The Company's capital budget for 2020 is expected to be in the range of $3.15 billion to $3.45 billion, consisting of $3.0 billion to $3.3 billion for drilling and completion related activities, including additional tank batteries and saltwater disposal facilities, and $125 million for water infrastructure. The 2020 capital budget excludes acquisitions, asset retirement obligations, capitalized interest and geological and geophysical general and administrative expense and corporate facilities.

The 2020 capital budget is expected to be funded from operating cash flow, and, if necessary, from cash and cash equivalents on hand, sales of investments, or borrowings under the Company's credit facility.

Divestitures, Decommissioning and Restructuring Activities

Divestitures.

In December 2019, the Company completed the sale of certain vertical and horizontal wells and approximately 4,500 undeveloped acres in Glasscock County of the Permian Basin to an unaffiliated third party for net cash proceeds of $64 million. The Company recorded a gain of $10 million associated with the sale.

In July 2019, the Company completed the sale of certain vertical wells and approximately 1,400 undeveloped acres in Martin County of the Permian Basin to an unaffiliated third party for net cash proceeds of $27 million. The Company recorded a gain of $26 million associated with the sale.

In June 2019, the Company completed the sale of certain vertical wells and approximately 1,900 undeveloped acres in Martin County of the Permian Basin to an unaffiliated third party for net cash proceeds of $38 million. The Company recorded a gain of $31 million associated with the sale.

In May 2019, the Company completed the sale of its Eagle Ford assets and other remaining assets in South Texas (the "South Texas Divestiture") to an unaffiliated third party in exchange for total consideration having an estimated fair value of $210 million. The fair value of the consideration included (i) net cash proceeds of $2 million, (ii) $136 million in contingent consideration and (iii) a $72 million receivable associated with estimated deficiency fees to be paid by the buyer. Of the total consideration, $208 million is considered a noncash investing activity for the year ended December 31, 2019. The Company recorded a loss of $525 million and recognized employee-related charges of $19 million associated with the sale.

In December 2018, the Company completed the sale of its pressure pumping assets to ProPetro Holding Corp. ("ProPetro") in exchange for total consideration of $282 million, comprised of 16.6 million shares of ProPetro's common stock, which was delivered as of the date of the sale and had a fair value of $172 million, and $110 million in cash, which was received during the first quarter of 2019. During 2018, the Company recorded a gain of $30 million, employee-related charges of $19 million, contract termination charges of $13 million and other divestiture-related charges of $6 million associated with the sale. During 2019, the Company reduced the gain associated with the sale by $10 million and recorded additional employee-related charges of $1 million.

In December 2018, the Company completed the sale of approximately 2,900 net acres in the Sinor Nest (Lower Wilcox) oil field in South Texas to an unaffiliated third party for net cash proceeds of $105 million. During 2018, the Company recorded a gain of $54 million associated with the sale.

In August 2018, the Company completed the sale of its assets in the West Panhandle gas and liquids field to an unaffiliated third party for net cash proceeds of $170 million. During 2018, the Company recorded a gain of $127 million and employee-related charges of $7 million associated with the sale.

In July 2018, the Company completed the sale of its gas field assets in the Raton Basin to an unaffiliated third party for net cash proceeds of $54 million. The Company recorded a noncash impairment charge of $77 million in June 2018 to reduce the carrying value of its Raton Basin assets to their estimated fair value less costs to sell as the assets were considered held for sale. During 2018, the Company recorded a gain of $2 million associated with this divestiture. The Company also recorded divestiture-related charges of $117 million, including $111 million of deficiency charges related to certain firm transportation contracts retained by the Company and employee-related charges of $6 million.

In April 2018, the Company completed the sale of approximately 10,200 net acres in the West Eagle Ford Shale gas and liquids field to an unaffiliated third party for net cash proceeds of $100 million. During 2018, the Company recorded a gain of $75 million associated with the sale.

Decommissioning.

In November 2018, the Company announced plans to close its sand mine located in Brady, Texas and transition its proppant supply requirements to West Texas sand sources.

- During 2019, the Company recorded $23 million of accelerated depreciation, $13 million of inventory and other property and equipment impairment charges and $12 million of sand mine closure-related costs.
- During 2018, the Company recorded $443 million of accelerated depreciation and $7 million of employee-related charges associated with the pending shutdown.

Restructuring.

During 2019, the Company implemented the Corporate Restructuring Program to align its cost structure with the needs of a Permian Basin-focused company. The restructuring occurred in three phases as follows:

- In March 2019, the Company made certain changes to its leadership and organizational structure, which included the early retirement and departure of certain officers of the Company,
- In April 2019, the Company adopted a voluntary separation program ("VSP") for certain eligible employees, and
- In May 2019, the Company implemented an involuntary separation program ("ISP").

During 2019, the Company recorded $159 million of employee-related charges, including $26 million of noncash stock-based compensation expense related to the accelerated vesting of certain equity awards, associated with the Corporate Restructuring Program.

See Note 3 and Note 4 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding Divestitures, Decommissioning and Restructuring activities.

Results of Operations

Results of operations should be read together with the Company's consolidated financial statements and related notes included in "Item 8. Financial Statements and Supplementary Data" of this Annual Report on Form 10-K. See the Company's Annual Report on Form 10-K for the year ended December 31, 2018 for a discussion of the Company's 2018 results of operations as compared to the Company's 2017 results of operations.

Oil and gas revenues.

	Year Ended December 31,		
	2019	2018	Change
	(in millions)		
Oil and gas revenues	$ 4,916	$ 4,991	$ (75)

Average daily sales volumes are as follows:

	Year Ended December 31,		
	2019	2018	% Change
Oil (Bbls)	212,353	190,639	11%
NGLs (Bbls)	72,323	63,780	13%
Gas (Mcf) (a)	365,055	393,391	(7%)
Total (BOE)	345,518	319,984	8%

(a) Gas production excludes gas produced and used as field fuel.

Average daily sales volumes per BOE increased for the year ended December 31, 2019, as compared to 2018, primarily due to the Company's successful Spraberry/Wolfcamp horizontal drilling program, which more than offset the loss of production associated with the Company's 2019 and 2018 divestitures.

The oil, NGL and gas prices reported by the Company are based on the market prices received for each commodity. The average prices are as follows:

	Year Ended December 31,		
	2019	2018	% Change
Oil per Bbl	$ 53.77	$ 57.36	(6%)
NGLs per Bbl	$ 19.33	$ 29.84	(35%)
Gas per Mcf	$ 1.79	$ 2.13	(16%)
Total per BOE	$ 38.98	$ 42.73	(9%)

Sales of purchased oil and gas. The Company enters into pipeline capacity commitments in order to secure available oil, NGL and gas transportation capacity from the Company's areas of production. The Company also enters into purchase transactions with third parties and separate sale transactions with third parties to diversify a portion of the Company's oil and gas sales to Gulf Coast refineries and LNG facilities, international export markets and to satisfy unused gas pipeline capacity commitments. Revenues and expenses from these transactions are presented on a gross basis as the Company acts as a principal in the transaction by assuming both the risk and rewards of ownership, including credit risk, of the commodities purchased and the responsibility to deliver the commodities sold. The transportation costs associated with these transactions are presented on a net basis in purchased oil and gas expense.

The net effect of third party purchases and sales of oil and gas is as follows:

	Year Ended December 31,		
	2019	2018	Change
	(in millions)		
Sales of purchased oil and gas	$ 4,755	$ 4,388	$ 367
Purchased oil and gas	4,472	3,930	542
Net effect on earnings	$ 283	$ 458	$ (175)

The $175 million decrease in net sales of purchased oil and gas for the year ended December 31, 2019, as compared to 2018, is primarily due to a decrease in downstream oil margins on the Company's Gulf Coast refinery and export sales.

Firm transportation payments on excess pipeline capacity are included in other expense in the accompanying consolidated statements of operations. See Note 16 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Interest and other income.

	Year Ended December 31,		
	2019	2018	Change
	(in millions)		
Interest and other income, net	$ 76	$ 38	$ 38

The increase in interest and other income for the year ended December 31, 2019, as compared to 2018, is primarily due to receiving net proceeds of $56 million from the sale of the Company's investment in its new corporate headquarters offset by noncash valuation adjustments associated with the Company's investment in an affiliate and contingent consideration received in the sale of the Company's Eagle Ford assets and other remaining South Texas assets in 2019.

See Note 15 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Derivative gain (loss), net.

	Year Ended December 31,		
	2019	2018	Change
	(in millions)		
Noncash derivative gain (loss), net	$ (13)	$ 270	$ (283)
Cash receipts (payments) on settled derivative instruments, net	47	(562)	609
Derivative gain (loss), net	$ 34	$ (292)	$ 326

The Company primarily utilizes commodity swap contracts, option contracts, collar contracts, collar contracts with short puts and basis swap contracts to (i) reduce the effect of price volatility on the commodities the Company produces and sells or consumes, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects.

Commodity derivatives and the relative price impact are as follows:

	Year Ended December 31,			
	2019		2018	
	Net cash receipts (payments)	Price impact	Net cash (payments) (a)	Price impact (a)
	(in millions)		(in millions)	
Oil derivative receipts (payments)	$ 75	$ 0.97 per Bbl	$ (451)	$ (6.48) per Bbl
NGL derivative payments	—	$ — per Bbl	(1)	$ (0.05) per Bbl
Gas derivative payments	(28)	$ (0.21) per Mcf	(22)	$ (0.15) per Mcf
Total net commodity derivative receipts (payments)	$ 47		$ (474)	

(a) Excludes the effect of liquidating the Company's NYMEX WTI collar contracts with short puts and its Brent swap contracts for cash payments of $81 million and its ethane basis contracts for cash payments of $4 million. Also excludes the effect of non-commodity derivative cash payments of $3 million.

The Company's open derivative contracts are subject to continuing market risk. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note 5 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Gain (loss) on disposition of assets, net.

	Year Ended December 31,		
	2019	2018	Change
		(in millions)	
Gain (loss) on disposition of assets, net	$ (477)	$ 290	$ (767)

The Company's gain (loss) on disposition of assets is primarily attributable to the following divestitures:

Asset Sold	Completion Date	Net Gain (Loss) Recorded
		(in millions)
Year Ended December 31, 2019:		
Martin County - Permian Basin acreage	June/July 2019	$ 57
Eagle Ford and remaining South Texas assets	May 2019	$ (525)
Other		$ (9)
Year Ended December 31, 2018:		
Pressure pumping assets	December 2018	$ 30
Sinor Nest (Lower Wilcox) oil field (South Texas)	December 2018	$ 54
West Panhandle gas and liquids field (Texas Panhandle)	August 2018	$ 127
Western portion of Eagle Ford Shale gas and liquids field (South Texas)	April 2018	$ 75
Other		$ 4

See Note 3 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Oil and gas production costs.

	Year Ended December 31,		
	2019	2018	Change
	(in millions)		
Oil and gas production costs	$ 874	$ 855	$ 19

Total production costs per BOE are as follows

	Year Ended December 31,		
	2019	2018	% Change
Lease operating expense (a)	$ 4.57	$ 4.29	7%
Gathering, processing and transportation expense (b)	2.24	2.52	(11%)
Workover costs (a)	0.71	0.92	(23%)
Net natural gas plant income (c)	(0.59)	(0.41)	44%
	$ 6.93	$ 7.32	(5%)

(a) Lease operating expense and workover expense represent the components of oil and gas production costs over which the Company has management control.
(b) Gathering, processing and transportation expense represents the costs to gather, process and transport the Company's gas to the point of sale.
(c) Net natural gas plant income represents the earnings from the Company's ownership share of gas processing facilities that gather and process the Company's and third party gas.

Lease operating expense per BOE increased for the year ended December 31, 2019, as compared to 2018, primarily due to higher maintenance costs associated with the Company's vertical wells in the Permian Basin. Gathering, processing and transportation decreased due to a greater proportion of the Company's production volumes coming from the Permian Basin, which have lower per BOE gathering, processing and transportation costs. The net natural gas plant income per BOE primarily reflects increased throughput of volumes that are processed in gas processing facilities that the Company has an ownership interest due to additional gas plants being brought online in 2019. The decrease in workover costs per BOE was primarily due to a reduction in workover activity on vertical wells.

Production and ad valorem taxes.

	Year Ended December 31,		
	2019	2018	Change
	(in millions)		
Production and ad valorem taxes	$ 299	$ 284	$ 15

In general, production taxes and ad valorem taxes are directly related to commodity price changes; however, Texas ad valorem taxes are based upon prior year commodity prices, whereas production taxes are based upon current year commodity prices.

Production and ad valorem taxes per BOE are as follows:

	Year Ended December 31,		
	2019	2018	% Change
Production taxes	$ 1.75	$ 1.83	(4%)
Ad valorem taxes	0.63	0.60	5%
	$ 2.38	$ 2.43	(2%)

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

	Year Ended December 31,		
	2019	2018	Change
	(in millions)		
Depletion, depreciation and amortization	$ 1,711	$ 1,534	$ 177

Total DD&A expense per BOE is as follows:

	Year Ended December 31,		
	2019	2018	% Change
DD&A per BOE	$ 13.56	$ 13.13	3%
Depletion expense per BOE	$ 12.78	$ 12.52	2%

The increase in DD&A per BOE and depletion expense per BOE is primarily due to the Company's divested assets, which had a lower depletion per BOE rate.

Impairment of oil and gas properties and other long-lived assets. The Company performs assessments of its long-lived assets to be held and used, including oil and gas properties, whenever events or circumstances indicate that the carrying values of those assets may not be recoverable. As a result of the Company's impairment assessments, the Company recorded noncash impairment charges in 2018 to reduce the carrying value of its Raton Basin gas field assets by $77 million.

See Note 2 and Note 4 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Exploration and abandonments expense.

	Year Ended December 31,		
	2019	2018	Change
		(in millions)	
Geological and geophysical	$ 49	$ 85	$ (36)
Exploratory well costs	4	23	(19)
Leasehold abandonments and other	5	6	(1)
	$ 58	$ 114	$ (56)

The decrease in geological and geophysical costs is primarily due to a decrease in geological and geophysical personnel costs as a result of the Corporate Restructuring Program. The decrease in exploration and abandonments expense for the year ended December 31, 2019, as compared to 2018, is primarily due to a decrease in unsuccessful Eagle Ford exploratory well costs.

During 2019 and 2018, the Company completed and evaluated 281 and 261 exploration/extension wells, respectively, and 100 percent and 96 percent, respectively, were successfully completed as discoveries.

General and administrative expense.

	Year Ended December 31,		
	2019	2018	Change
		(in millions)	
General and administrative expense	$ 324	$ 381	$ (57)

	Year Ended December 31,		
	2019	2018	% Change
General and administrative expense per BOE	$ 2.57	$ 3.26	(21%)

The decrease in general and administrative expense for the year ended December 31, 2019, as compared to 2018, was primarily due to a decrease in compensation costs, including benefits expense, as a result of the Company's 2019 Corporate Restructuring Program.

Interest expense.

	Year Ended December 31,		
	2019	2018	Change
	(in millions)		
Interest expense	$ 121	$ 126	$ (5)

The weighted average interest rate on the Company's indebtedness for the year ended December 31, 2019 is 5.3 percent, as compared to 5.4 percent for the year ended December 31, 2018.

See Note 7 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Other expense.

	Year Ended December 31,		
	2019	2018	Change
	(in millions)		
Other expense	$ 448	$ 849	$ (401)

The decrease in other expense for the year ended December 31, 2019, as compared to 2018, is primarily related to a noncash charge of $443 million in 2018 associated with the Company's closure of its Brady, Texas sand mine and $170 million of asset divestiture-related charges associated with the sale of the Company's pressure pumping assets and oil and gas properties during 2018. The decrease was partially offset by $159 million of restructuring charges associated with the Company's Corporate Restructuring Program during 2019.

See Note 16 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Income tax provision.

	Year Ended December 31,		
	2019	2018	Change
	(in millions)		
Income tax provision	231	276	$ (45)
Effective tax rate	23%	22%	1%

The decrease in the income tax provision for the year ended December 31, 2019, as compared to 2018, is primarily due to a decrease of $264 million in income before income taxes.

See Note 17 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Liquidity and Capital Resources

Liquidity. The Company's primary sources of short-term liquidity are (i) cash and cash equivalents, (ii) net cash provided by operating activities, (iii) sales of investments, (iv) unused borrowing capacity under its credit facility (the "Credit Facility"), (v) issuances of debt or equity securities and (vi) other sources, such as sales of nonstrategic assets.

The Company's primary needs for cash are for (i) capital expenditures, (ii) acquisitions of oil and gas properties, (iii) payments of contractual obligations, including debt maturities, (iv) dividends and share repurchases and (v) working capital obligations. Funding for these cash needs may be provided by any combination of the Company's sources of liquidity. Although the Company expects that its sources of funding will be adequate to fund its 2020 capital expenditures, dividend payments and provide adequate liquidity to fund other needs, including stock repurchases, no assurance can be given that such funding sources will be adequate to meet the Company's future needs.

2020 capital budget. The Company' capital budget for 2020 is expected to be in the range of $3.15 billion to $3.45 billion, consisting of $3.0 billion to $3.3 billion for drilling and completion related activities, including additional tank batteries and saltwater disposal facilities, and $125 million for water infrastructure. The 2020 capital budget excludes acquisitions, asset retirement obligations, capitalized interest, geological and geophysical general and administrative expense and corporate facilities.

Capital resources. See the Company's Annual Report on Form 10-K for the year ended December 31, 2018 for a discussion of the Company's 2018 capital resources as compared to the Company's 2017 capital resources.

As of December 31, 2019, the Company had no outstanding borrowings under its Credit Facility, leaving $1.5 billion of unused borrowing capacity. The Company was in compliance with all of its debt covenants as of December 31, 2019. The Company also had cash on hand of $631 million as of December 31, 2019.

	Year Ended December 31,		
	2019	2018	Change
	(in millions)		
Net cash provided by operating activities	$ 3,115	$ 3,242	$ (127)
Net cash used in investing activities	$ (2,447)	$ (2,610)	$ (163)
Net cash used in financing activities	$ (788)	$ (703)	$ 85

Operating activities. The decrease in net cash flow provided by operating activities in 2019, as compared to 2018, is primarily due to decreases in the Company's oil and gas revenues as a result of decreases in commodity prices.

Investing activities. The decrease in net cash flow used in investing activities during 2019, as compared to 2018, is primarily due to a decrease of $532 million in capital expenditures related to oil and gas properties offset by a $320 million decrease in net cash proceeds from the disposition of assets. The Company's investing activities during the year ended December 31, 2019 were primarily funded by net cash provided by operating activities.

Financing activities. The Company's significant financing activities are as follows:

- 2019: The Company repurchased $653 million of its common stock and paid dividends of $127 million.
- 2018: The Company repaid $450 million associated with the maturity of its 6.875% senior notes, repurchased $179 million of its common stock and paid dividends of $55 million.

Dividends/distributions. During the year ended December 31, 2019, the Company's board of directors declared dividends of $1.20 per common share, compared to dividends declared of $0.32 per common share during the year ended December 31, 2018. The Company paid aggregate dividends of $127 million during 2019 and $55 million during 2018. In addition, on February 19, 2020, the board of directors declared a quarterly cash dividend of $0.55 per share on the Company's outstanding common stock, payable April 14, 2020 to stockholders of record at the close of business on March 31, 2020. Future dividends are at the discretion of the Company's board of directors, and, if declared, the board of directors may change the dividend amount based on the Company's liquidity and capital resources at the time.

Off-balance sheet arrangements. From time to time, the Company enters into arrangements and transactions that can give rise to material off-balance sheet obligations of the Company. As of December 31, 2019, the material off-balance sheet arrangements and transactions that the Company had entered into included (i) operating lease agreements related to contracted drilling rigs whose terms have not commenced, (ii) firm purchase, transportation, storage and fractionation commitments, (iii) open purchase commitments and (iv) contractual obligations for which the ultimate settlement amounts are not fixed and determinable. The contractual obligations for which the ultimate settlement amounts are not fixed and determinable include (i) derivative contracts that are sensitive to future changes in commodity prices or interest rates, (ii) gathering, processing (primarily treating and fractionation) and transportation commitments on uncertain volumes of future throughput, (iii) open purchase commitments and (iv) indemnification obligations following certain divestitures. Other than the off-balance sheet arrangements described above, the Company has no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect the Company's liquidity or availability of or requirements for capital resources. The Company expects to enter into similar contractual arrangements in the future, including incremental derivative contracts and additional firm purchase, transportation, storage and fractionation arrangements, in order to support the Company's business plans. See "Contractual obligations" below and Note 11 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Contractual obligations. The Company's contractual obligations include long-term debt, leases (primarily related to contracted drilling rigs, equipment and office facilities), capital funding obligations, derivative obligations, firm transportation, storage and fractionation commitments, minimum annual gathering, processing and transportation commitments and other liabilities (including postretirement benefit obligations). Other joint owners in the properties operated by the Company could incur portions of the costs represented by these commitments.

Contractual obligations are estimated as follows:

	Payments Due by Year			
	2020	2021 and 2022	2023 and 2024	Thereafter
	(in millions)			
Firm commitments (a)	$ 532	$ 1,005	$ 819	$ 1,784
Long-term debt (b)	450	1,100	—	750
Purchase commitments (c)	236	18	3	—
Leases (d)	187	225	105	621
Derivative obligations (e)	12	8	—	—
Other liabilities (f)	333	282	91	122
Total contractual obligations	$ 1,750	$ 2,638	$ 1,018	$ 3,277

(a) Firm purchase, gathering, processing, transportation, storage and fractionation commitments represent take-or-pay agreements, which include (i) contractual commitments to purchase sand and water for use in the Company's drilling operations and (ii) estimated fees on production throughput commitments and demand fees associated with volume delivery or storage commitments. The Company does not expect to be able to fulfill all of its short-term and long-term volume delivery obligations from projected production of available reserves; consequently, the Company plans to purchase third party volumes to satisfy its commitments if it is economic to do so; otherwise, it will pay demand fees for any commitment shortfalls. See "Item 2. Properties" and Note 11 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

(b) The amounts included in the table above represent principal maturities only. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note 7 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

(c) Open purchase commitments primarily represent expenditure commitments for inventories, materials and other property and equipment ordered, but not received, as of December 31, 2019.

(d) The amounts represent future minimum lease payments associated long-term lease contracts to which the Company was a party and had commenced as of December 31, 2019. See Note 10 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

(e) Derivative obligations represent net liabilities determined in accordance with master netting arrangements for commodity derivatives that were valued as of December 31, 2019. The Company's commodity derivative contracts are periodically measured and recorded at fair value and continue to be subject to market and credit risk. The ultimate liquidation value of the Company's commodity derivatives will be dependent upon actual future commodity prices, which may differ materially from the inputs used to determine the derivatives' fair values as of December 31, 2019. See Note 5 and Note 11 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional information.

(f) The Company's other liabilities represent current and noncurrent other liabilities that are comprised of litigation and environmental contingencies, asset retirement obligations and other obligations for which neither the ultimate settlement amounts nor their timings can be precisely determined in advance. See Note 9 and Note 11 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Debt ratings. The Company is rated as mid-investment grade by three credit rating agencies. The Company receives debt credit ratings from several of the major ratings agencies, which are subject to regular reviews. The Company believes that each of the rating agencies considers many factors in determining the Company's ratings, including: (i) production growth opportunities, (ii) liquidity, (iii) debt levels, (iv) asset composition and (v) proved reserve mix. A reduction in the Company's debt ratings could increase the interest rates that the Company incurs on Credit Facility borrowings and could negatively impact the Company's ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing.

Book capitalization and current ratio. The Company's net book capitalization at December 31, 2019 was $13.8 billion, consisting of cash and cash equivalents of $631 million, debt of $2.3 billion and equity of $12.1 billion. The Company's net debt to book capitalization increased to 12 percent at December 31, 2019 from seven percent at December 31, 2018, primarily due to funding the Company's share repurchases with cash and cash equivalents. The Company's ratio of current assets to current liabilities was 0.88:1 at December 31, 2019, as compared to 1.42:1 at December 31, 2018.

Critical Accounting Estimates

The Company prepares its consolidated financial statements for inclusion in this Report in accordance with GAAP. See Note 2 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information. The following is a discussion of the Company's most critical accounting estimates, judgments and uncertainties that are inherent in the Company's application of GAAP.

Asset retirement obligations. The Company has significant obligations to remove tangible equipment and facilities and to restore the land at the end of oil and gas production operations. The Company's removal and restoration obligations are primarily associated with plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, credit-adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligations, a corresponding adjustment is generally made to the oil and gas property or other property and equipment balance. See Note 9 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Successful efforts method of accounting. The Company utilizes the successful efforts method of accounting for oil and gas producing activities as opposed to the alternate acceptable full cost method. In general, the Company believes that net assets and net income are more conservatively measured under the successful efforts method of accounting for oil and gas producing activities than under the full cost method, particularly during periods of active exploration. The critical difference between the successful efforts method of accounting and the full cost method is that under the successful efforts method, exploratory dry holes and geological and geophysical exploration costs are charged against earnings during the periods in which they occur; whereas, under the full cost method of accounting, such costs and expenses are capitalized as assets, pooled with the costs of successful wells and charged against the earnings of future periods as a component of depletion expense.

Proved reserve estimates. Estimates of the Company's proved reserves included in this Report are prepared in accordance with GAAP and SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

The Company's proved reserve information included in this Report as of December 31, 2019, 2018 and 2017 was prepared by the Company's engineers and audited by independent petroleum engineers with respect to the Company's major properties. Estimates prepared by third parties may be higher or lower than those included herein.

Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, proved reserve estimates will be different from the quantities of oil and gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify, positively or negatively, material revisions to the estimate of proved reserves.

It should not be assumed that the Standardized Measure included in this Report as of December 31, 2019 is the current market value of the Company's estimated proved reserves. In accordance with SEC requirements, the Company based the 2019 Standardized Measure on a twelve month average of commodity prices on the first day of each month in 2019 and prevailing costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs utilized in the estimate. See "Item 2. Properties" and Unaudited Supplementary Information included in "Item 8. Financial Statements and Supplementary Data" for additional information.

The Company's estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, the rate at which the Company records depletion expense will increase, reducing future net income. Such a decline may result from lower commodity prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of the Company's assessment of its proved properties and goodwill for impairment.

Impairment of proved oil and gas properties. The Company reviews its proved properties to be held and used whenever management determines that events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. Management assesses whether or not an impairment provision is necessary based upon estimated future recoverable proved and risk-adjusted probable and possible reserves, Management's Price Outlooks, production and capital costs expected to be incurred to recover the reserves, discount rates commensurate with the nature of the properties and net cash flows that may be generated by the properties. Proved oil and gas properties are reviewed for impairment at the level at which depletion of proved properties is calculated. See Note 4 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Impairment of unproved oil and gas properties. At December 31, 2019, the Company carried unproved property costs of $584 million. Management assesses unproved oil and gas properties for impairment on a project-by-project basis. Management's impairment assessments include evaluating the results of exploration activities, Management's Price Outlooks and planned future sales or expiration of all or a portion of such projects.

Suspended wells. The Company suspends the costs of exploratory wells that discover hydrocarbons pending a final determination of the commercial potential of the discovery. The ultimate disposition of these well costs is dependent on the results of future drilling activity and development decisions. If the Company decides not to pursue additional appraisal activities or development of these fields, the costs of these wells will be charged to exploration and abandonment expense.

The Company does not carry the costs of drilling an exploratory well as an asset in its consolidated balance sheets following the completion of drilling unless both of the following conditions are met:

(i) The well has found a sufficient quantity of reserves to justify its completion as a producing well; and
(ii) The Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Due to the capital intensive nature and the geographical location of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and being pursued constantly. Consequently, the Company's assessment of suspended exploratory well costs is continuous until a decision can be made that the well has found sufficient quantities of proved reserves to sanction the project or is determined to be noncommercial and is impaired. See Note 6 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Deferred tax asset valuation allowances. The Company continually assesses both positive and negative evidence to determine whether it is more likely than not that its deferred tax assets will be realized prior to their expiration. Pioneer monitors Company-specific, oil and gas industry and worldwide economic factors and based on that information, along with other data, reassesses the likelihood that the Company's net operating loss carryforwards and other deferred tax attributes in each jurisdiction will be utilized prior to their expiration. There can be no assurance that facts and circumstances will not materially change and require the Company to establish deferred tax asset valuation allowances in certain jurisdictions in a future period.

Uncertain tax positions. The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based upon the technical merits of the position. The Company has unrecognized tax benefits for tax years 2016-2018 ("UTBs") resulting from research and experimental expenditures related to horizontal drilling and completion innovations. If all or a portion of the UTBs is sustained upon examination by the taxing authorities, the tax benefit will be recorded as a reduction to the Company’s deferred tax liability and will affect the Company’s effective tax rate in the period it is recorded. In December 2019, the Company and the taxing authorities effectively settled the uncertain tax position for the 2012-2015 tax years. The Company believes it will substantially resolve the uncertainties associated with the remaining UTB within the next twelve months. See Note 17 of Notes to the Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Goodwill impairment. The Company reviews its goodwill for impairment at least annually. During the third quarter of 2019, the Company performed a qualitative assessment of goodwill to assess whether it was more likely than not that the fair value of the Company's reporting unit was less than its carrying amount as a basis for determining whether it was necessary to record a noncash impairment charge. The Company determined that it was more likely than not that the Company's goodwill was not impaired. There is considerable judgment involved in estimating fair values, particularly in determining the valuation methodologies to utilize, the estimation of proved reserves as described above and the weighting of different valuation methodologies applied.

Litigation and environmental contingencies. The Company makes judgments and estimates in recording liabilities for ongoing litigation and environmental remediation. Actual costs can vary from such estimates for a variety of reasons. The costs to settle litigation can vary from estimates based on differing interpretations of laws and opinions and assessments on the amount of damages. Similarly, environmental remediation liabilities are subject to change because of changes in laws and regulations, developing information relating to the extent and nature of site contamination and improvements in technology. A liability is recorded for these types of contingencies if the Company determines the loss to be both probable and reasonably estimable. See Note 11 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Valuation of stock-based compensation. The Company calculates the fair value of stock-based compensation using various valuation methods. The valuation methods require the use of estimates to derive the inputs necessary to determine fair value. The Company utilizes (i) the Black-Scholes option pricing model to measure the fair value of stock options, (ii) the closing stock price on the day prior to the date of grant for the fair value of restricted stock awards, (iii) the closing stock price on the balance sheet date for restricted stock awards that are expected to be settled wholly or partially in cash on their vesting date and (iv) the Monte Carlo simulation method for the fair value of performance unit awards. See Note 8 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Valuation of other assets and liabilities at fair value. The Company periodically measures and records certain assets and liabilities at fair value. The assets and liabilities that the Company measures and records at fair value on a recurring basis include trading securities, commodity derivative contracts and interest rate contracts. Other assets are not measured at fair value on an ongoing basis, but are subject to fair value adjustments in certain circumstances. The assets and liabilities that the Company measures and records at fair value on a nonrecurring basis include inventories, proved and unproved oil and gas properties, assets acquired and liabilities assumed in business combinations and other long-lived assets that are written down to fair value when they are determined to be impaired or held for sale. The Company also measures and discloses certain financial assets and liabilities at fair value, such as long-term debt and investments. The valuation methods used by the Company to measure the fair values of these assets and liabilities may require considerable management judgment and estimates to derive the inputs necessary to determine fair value estimates, such as future prices, credit-adjusted risk-free rates and current volatility factors. See Note 4 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

New Accounting Pronouncements

The effects of new accounting pronouncements are discussed in Note 2 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

In the normal course of business, the Company's financial position is routinely subject to a variety of risks, including market risks associated with changes in commodity prices, interest rate movements on outstanding debt and credit risks. These risks are mitigated through the Company's risk management program, which includes the use of derivative financial instruments and sales of purchased oil and gas. The following quantitative and qualitative information is provided about financial instruments to which the Company was a party as of December 31, 2019, and from which the Company may incur future gains or losses from changes in commodity prices or interest rates. The Company does not enter into any financial instruments, including derivatives, for speculative or trading purposes.

Interest rate risk. As of December 31, 2019, the Company had no variable rate debt outstanding under its credit facility and therefore no related exposure to interest rate risk. As of December 31, 2019, the Company had $2.3 billion of fixed rate long-term debt outstanding with an weighted average interest rate of 5.3 percent. Although changes in interest rates may affect the fair value of the Company's fixed rate long-term debt, any changes would not expose the Company to the risk of material earnings or cash flow losses. The Company did not have any interest rate derivative instruments outstanding as of December 31, 2019, however it may enter into additional such instruments in the future to mitigate interest rate risk. See Note 4, Note 5 and Note 7 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Commodity price risk. The Company's primary market risk exposure is in the price it receives from the sale of its oil, NGL and gas production. Realized pricing is volatile and is determined by market prices that fluctuate with changes in supply and demand for these products throughout the world. The price the Company receives for its production depends on many factors outside of the control of the Company, including differences in commodity pricing at the point of sale versus various index prices. Reducing the Company's exposure to price volatility helps secure funds to be used in its capital program. The Company mitigates its commodity price risk through the use of derivative financial instruments and sales of purchased oil and gas.

Derivative financial instruments. The Company's decision on the quantity and price at which it executes derivative contracts is based in part on its view of current and future market conditions. The Company may choose not to enter into derivative positions for expected production if the price environment for certain time periods is deemed to be unfavorable. Additionally, the Company may choose to liquidate existing derivative positions prior to the expiration of their contractual maturity in order to monetize gain positions for the purpose of funding its capital program, dividends and share repurchases. While derivative positions limit the downside risk of adverse price movements, it also limits future revenues from upward price movements. The Company manages commodity price risk with the following types of derivative contracts:

- *Swaps.* The Company receives a fixed price and pays a floating market price to the counterparty on a notional amount of sales volumes, thereby fixing the price for the commodity sold.
- *Collars.* Collar contracts provide minimum ("floor" or "long put") and maximum ("ceiling") prices on a notional amount of sales volumes, thereby allowing some price participation if the relevant index price closes above the floor price but below the ceiling price.
- *Collar contracts with short put options.* Collar contracts with short put options differ from other collar contracts by virtue of the short put option price, below which the Company's realized price will exceed the variable market prices by the long put-to-short put price differential.
- *Basis swaps.* Basis swap contracts fix the basis differentials between the index price at which the Company sells its production and the index price used in swap or collar contracts.
- *Options.* Selling individual call options can enhance the market price by the premium received or the premium received can be utilized to improve swap or collar contract prices. Purchased put options establish a minimum floor price (less any premiums paid) and allows participation in higher prices when prices close above the floor price.

The Company has entered into derivative contracts for a portion of its forecasted 2020 and 2021 production; consequently, if commodity prices decline, the Company could realize lower prices for volumes not protected by the Company's derivative activities and could see a reduction in derivative contract prices available for additional volumes in the future. As a result, the Company's internal cash flows will be negatively impacted by a reduction in commodity prices.

The average forward prices based on December 31, 2019 market quotes are as follows:

	2020				Year Ending December 31, 2021
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	
Average forward Brent oil price	$ 65.32	$ 63.49	$ 62.04	$ 60.87	$ 58.90
Average forward NYMEX gas price	$ 2.17	$ 2.19	$ 2.31	$ 2.46	$ 2.42
Permian Basin gas index swap contracts:					
Average forward basis differential price (a)	$ —	$ (1.89)	$ (1.30)	$ (1.50)	$ —

The average forward prices based on February 18, 2020 market quotes are as follows:

	2020				Year Ending December 31, 2021
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	
Average forward Brent oil price	$ 57.63	$ 57.43	$ 57.20	$ 56.87	$ 56.36
Average forward NYMEX gas price	$ 1.98	$ 2.01	$ 2.13	$ 2.32	$ 2.36
Permian Basin index swap contracts:					
Average forward basis differential price (a)	$ —	$ (2.07)	$ (1.82)	$ (2.01)	$ (1.29)

(a) Based on market quotes for basis differentials between Permian Basin gas index prices and the NYMEX Henry Hub index price.

See Note 4 and Note 5 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of the Company's open derivative positions and additional information.

Sales of purchased oil and gas. The Company enters into pipeline capacity commitments in order to secure available oil, NGL and gas transportation capacity from the Company's areas of production. The Company also enters into purchase transactions with third parties and separate sale transactions with third parties to diversify a portion of the Company's oil and gas sales to Gulf Coast refineries and LNG facilities, international export markets and to satisfy unused gas pipeline capacity commitments.

Credit risk. The Company's primary concentration of credit risks are associated with the collection of receivables resulting from the sale of oil and gas production and purchased oil and gas and the risk of a counterparty's failure to meet its obligations under derivative contracts with the Company.

The Company's oil and gas is sold to various purchasers who must be prequalified under the Company's credit risk policies and procedures. The Company monitors exposure to counterparties primarily by reviewing credit ratings, financial criteria and payment history. Where appropriate, the Company obtains assurances of payment, such as a guarantee by the parent company of the counterparty, a letter of credit or other credit support. Historically, the Company's credit losses on oil and gas receivables have not been material.

The Company uses credit and other financial criteria to evaluate the credit standing of, and to select, counterparties to its derivative instruments. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative instruments, associated credit risk is mitigated by the Company's credit risk policies and procedures.

The Company has entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of its derivative counterparties. The terms of the ISDA Agreements provide the Company and the counterparties with right of set off upon the occurrence of defined acts of default by either the Company or a counterparty to a derivative contract, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note 5 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTAL DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Pioneer Natural Resources Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Pioneer Natural Resources Company (the Company) as of December 31, 2019 and 2018, the related consolidated statements of operations, equity and cash flows for each of the three years in the period ended December 31, 2019, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with U.S. generally accepted accounting principles.

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, 2019, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 24, 2020 expressed an unqualified opinion thereon.

Adoption of ASU No. 2014-09

As discussed in Note 2 to the consolidated financial statements, the Company changed its method for recognizing revenue as a result of the adoption of Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers (Topic 606), and the related amendments, effective January 1, 2018.

Basis for Opinion

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

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

Critical Audit Matters

The critical audit matters communicated below are matters 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) relate 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 consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

	Depreciation, Depletion and Amortization of Proved Oil and Gas Properties
Description of the Matter	At December 31, 2019, the net book value of the Company’s proved oil and gas properties was $13,861 million, and depreciation, depletion and amortization (DD&A) expense was $1,711 million for the year then ended. As described in Note 2, under the successful efforts method of accounting, capitalized costs of proved properties are depleted using the units-of-production method based on proved reserves, as estimated by the Company’s engineers. Proved oil and gas reserve estimates are based on geological and engineering interpretation and judgment. Significant judgment is required by the Company’s engineers in evaluating geological and engineering data when estimating proved oil and gas reserves. Estimating reserves also requires the selection of inputs, including oil and gas price assumptions, future operating and capital cost assumptions and tax rates by jurisdiction, among others. Because of the complexity involved in estimating oil and gas reserves, management used independent petroleum engineers to audit the estimates prepared by the Company’s engineers as of December 31, 2019.

Auditing the Company’s DD&A calculation is especially complex because of the use of the work of the Company’s engineers and the independent petroleum engineers and the evaluation of management’s determination of the inputs described above used by the engineers in estimating proved oil and gas reserves.

How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design and tested the operating effectiveness of the Company’s controls over its process to calculate DD&A, including management’s controls over the completeness and accuracy of the financial data provided to the engineers for use in estimating proved oil and gas reserves. Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company’s engineers responsible for the preparation of the reserve estimates and the independent petroleum engineers used to audit the estimates. In addition, in assessing whether we can use of the work of the engineers, we evaluated the completeness and accuracy of the financial data and inputs described above used by the engineers in estimating proved oil and gas reserves by agreeing them to source documentation and we identified and evaluated corroborative and contrary evidence. For proved undeveloped reserves, we evaluated management’s development plan for compliance with SEC requirements. We also tested the mathematical accuracy of the DD&A calculations, including comparing the proved oil and gas reserves amounts used to the Company’s reserve report.
	South Texas Divestiture
Description of the Matter	As disclosed in Note 3, the Company completed the sale of its Eagle Ford assets and other remaining assets in South Texas (collectively, the South Texas assets) to an unaffiliated third party in exchange for total consideration having an estimated fair value of $210 million. The estimated fair value of the consideration as of the date of the sale includes (i) net cash proceeds of $2 million, (ii) an estimated $136 million in contingent consideration based on commodity prices and (iii) $72 million in estimated reimbursements from the buyer associated with deficiency fees the Company is obligated to pay on minimum volume commitments related to the assets sold. The Company recorded an obligation of $348 million for the estimated fair value of the future obligation associated with the minimum volume commitments. The Company recorded a $525 million loss in connection with the sale. Auditing the Company’s accounting for the sale of its South Texas assets was complex because of the significant judgment used by management in accounting for the unique terms and conditions of the agreement, including the accounting for the consideration expected to be received that is contingent on future oil and NGL prices and the minimum volume commitment obligation and related reimbursement. Additionally, significant estimation by management was required to determine the fair value of the contingent consideration and minimum volume commitment obligation and related reimbursement, and the respective fair values were sensitive to the significant underlying assumptions. The Company used an option pricing model to determine the fair value of the contingent consideration. The significant assumptions used to estimate the fair value of the contingent consideration included discount rates, observable forward commodity prices, and implied volatility factors. The Company used a discounted cash flow model to determine the fair value of the minimum volume commitment liability and related reimbursement. The significant assumptions used to estimate the fair value of the minimum volume commitment obligation and related reimbursement included discount rates and unobservable assumptions with respect to various development plans that form the basis of the projected volumes to be produced based on future drilling. These significant assumptions are forward looking and could be affected by future economic and market conditions.
How We Addressed the Matter in Our Audit	We tested the Company's controls over its accounting for the divestiture of its South Texas assets, including controls over the accounting and valuation models and the recognition and measurement of the contingent consideration and the minimum volume commitment obligation and related reimbursement. We also tested controls over management’s review of underlying assumptions and inputs used in the valuation models. Our audit procedures included, among others, evaluating management’s accounting for the unique terms and conditions of the purchase and sale agreement. We also evaluated the valuation methodologies and significant assumptions used by management, and performed procedures to assess the completeness and accuracy of the underlying data supporting the significant assumptions and estimates. For example, we compared the significant assumptions to third-party industry projections for future commodity prices and related differentials used in the valuation of the contingent consideration. With respect to the minimum volume commitment obligation and related reimbursement, we compared drilling plan assumptions to the agreed-upon drilling schedule between the buyer and working interest owners and compared anticipated production information to historical production information for similar properties. We involved our valuation specialists to assist with our evaluation of the methodologies used by the Company and significant assumptions included in the fair value estimates.

/s/ Ernst & Young LLP
We have served as the Company's auditor since 1998.
Dallas, Texas
February 24, 2020

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS
(in millions)

	December 31, 2019	December 31, 2018
ASSETS		
Current assets:		
Cash and cash equivalents	$ 631	$ 825
Restricted cash	74	—
Short-term investments	—	443
Accounts receivable:		
Trade, net	1,032	694
Due from affiliates	3	120
Income taxes receivable	7	7
Inventories	205	242
Derivatives	32	52
Investment in affiliate	187	172
Other	20	25
Total current assets	2,191	2,580
Oil and gas properties, using the successful efforts method of accounting:		
Proved properties	22,444	21,165
Unproved properties	584	601
Accumulated depletion, depreciation and amortization	(8,583)	(8,218)
Total oil and gas properties, net	14,445	13,548
Other property and equipment, net	1,632	1,291
Operating lease right-of-use assets	280	—
Long-term investments	—	125
Goodwill	261	264
Other assets	258	95
	$ 19,067	$ 17,903

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS (continued)
(in millions, except share data)

	December 31, 2019	December 31, 2018
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 1,221	$ 1,441
Due to affiliates	190	183
Interest payable	53	53
Income taxes payable	3	2
Current portion of long-term debt	450	—
Derivatives	12	27
Operating leases	136	—
Other	431	112
Total current liabilities	2,496	1,818
Long-term debt	1,839	2,284
Derivatives	8	—
Deferred income taxes	1,389	1,152
Operating leases	170	—
Other liabilities	1,046	538
Equity:		
Common stock, $.01 par value; 500,000,000 shares authorized; 175,057,889 and 174,321,171 shares issued as of December 31, 2019 and 2018, respectively	2	2
Additional paid-in capital	9,161	9,062
Treasury stock, at cost; 9,511,248 and 4,822,069 shares as of December 31, 2019 and 2018, respectively	(1,069)	(423)
Retained earnings	4,025	3,470
Total equity	12,119	12,111
Commitments and contingencies		
	$ 19,067	$ 17,903

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per share data)

	Year Ended December 31,		
	2019	2018	2017
Revenues and other income:			
Oil and gas	$ 4,916	$ 4,991	$ 3,518
Sales of purchased oil and gas	4,755	4,388	1,776
Interest and other	76	38	53
Derivative gain (loss), net	34	(292)	(100)
Gain (loss) on disposition of assets, net	(477)	290	208
	9,304	9,415	5,455
Costs and expenses:			
Oil and gas production	874	855	591
Production and ad valorem taxes	299	284	215
Depletion, depreciation and amortization	1,711	1,534	1,400
Purchased oil and gas	4,472	3,930	1,807
Impairment of oil and gas properties	—	77	285
Exploration and abandonments	58	114	106
General and administrative	324	381	326
Accretion of discount on asset retirement obligations	10	14	19
Interest	121	126	153
Other	448	849	244
	8,317	8,164	5,146
Income before income taxes	987	1,251	309
Income tax (provision) benefit	(231)	(276)	524
Net income	756	975	833
Net loss attributable to noncontrolling interests	—	3	—
Net income attributable to common stockholders	$ 756	$ 978	$ 833
Net income per share attributable to common stockholders:			
Basic	$ 4.50	$ 5.71	$ 4.86
Diluted	$ 4.50	$ 5.70	$ 4.85
Basic and diluted weighted average shares outstanding	167	171	170

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF EQUITY
(in millions, except share data and dividends per share)

		Equity Attributable to Common Stockholders					
	Shares Outstanding	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Noncontrolling Interests	Total Equity
	(in thousands)						
Balance as of December 31, 2016	169,724	$ 2	$ 8,892	$ (218)	$ 1,728	$ 7	$ 10,411
Dividends declared ($0.08 per share)	—	—	—	—	(14)	—	(14)
Exercise of long term incentive plan stock options and employee stock purchases	81	—	1	5	—	—	6
Purchase of treasury stock	(191)	—	—	(36)	—	—	(36)
Compensation costs:							
Vested compensation awards, net	575	—	—	—	—	—	—
Compensation costs included in net income	—	—	79	—	—	—	79
Purchase of noncontrolling interest	—	—	2	—	—	(2)	—
Net income	—	—	—	—	833	—	833
Balance as of December 31, 2017	170,189	$ 2	$ 8,974	$ (249)	$ 2,547	$ 5	$ 11,279
Dividends declared ($0.32 per share)	—	—	—	—	(55)	—	(55)
Exercise of long-term incentive plan stock options and employee stock purchases	58	—	3	5	—	—	8
Purchase of treasury stock	(1,272)	—	—	(179)	—	—	(179)
Compensation costs:							
Vested compensation awards, net	524	—	—	—	—	—	—
Compensation costs included in net income	—	—	85	—	—	—	85
Sale of noncontrolling interest	—	—	—	—	—	(2)	(2)
Net income (loss)	—	—	—	—	978	(3)	975
Balance as of December 31, 2018	169,499	$ 2	$ 9,062	$ (423)	$ 3,470	$ —	$ 12,111

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF EQUITY (continued)
(in millions, except share data and dividends per share)

		Equity Attributable to Common Stockholders				
	Shares Outstanding	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total Equity
	(in thousands)					
Balance as of December 31, 2018	169,499	$ 2	$ 9,062	$ (423)	$ 3,470	$ 12,111
Dividends declared ($1.20 per share)	—	—	—	—	(201)	(201)
Exercise of long-term incentive plan stock options and employee stock purchases	64	—	(1)	7	—	6
Purchases of treasury stock	(4,753)	—	—	(653)	—	(653)
Compensation costs:						
Vested compensation awards, net	737	—	—	—	—	—
Compensation costs included in net income	—	—	100	—	—	100
Net income	—	—	—	—	756	756
Balance as of December 31, 2019	165,547	$ 2	$ 9,161	$ (1,069)	$ 4,025	$ 12,119

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2019	2018	2017
Cash flows from operating activities:			
Net income	$ 756	$ 975	$ 833
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation and amortization	1,711	1,534	1,400
Impairment of oil and gas properties	—	77	285
Impairment of inventory and other property and equipment	38	11	2
Exploration expenses, including dry holes	8	27	22
Deferred income taxes	236	274	(519)
(Gain) loss on disposition of assets, net	477	(290)	(208)
Accretion of discount on asset retirement obligations	10	14	19
Interest expense	9	5	5
Derivative related activity	13	(270)	174
Amortization of stock-based compensation	100	85	79
Investment in affiliate valuation adjustment	(15)	—	—
Contingent consideration valuation adjustment	45	—	—
Other	105	658	85
Change in operating assets and liabilities:			
Accounts receivable	(227)	(52)	(120)
Inventories	(20)	(70)	(35)
Other assets	(33)	3	(3)
Accounts payable	(7)	321	134
Interest payable	—	(5)	(9)
Other liabilities	(91)	(55)	(45)
Net cash provided by operating activities	3,115	3,242	2,099
Cash flows from investing activities:			
Proceeds from disposition of assets, net of cash sold	149	469	352
Proceeds from investments	624	1,373	1,467
Purchase of investments	—	(669)	(904)
Additions to oil and gas properties	(2,988)	(3,520)	(2,365)
Additions to other assets and other property and equipment, net	(232)	(263)	(342)
Net cash used in investing activities	(2,447)	(2,610)	(1,792)
Cash flows from financing activities:			
Principal payments on long-term debt	—	(450)	(485)
Payments of other liabilities	(14)	(23)	—
Exercise of long-term incentive plan stock options and employee stock purchases	6	8	6
Purchases of treasury stock	(653)	(179)	(36)
Payments of financing fees	—	(4)	—
Dividends paid	(127)	(55)	(14)
Net cash used in financing activities	(788)	(703)	(529)
Net decrease in cash, cash equivalents and restricted cash	(120)	(71)	(222)
Cash, cash equivalents and restricted cash, beginning of period	825	896	1,118
Cash, cash equivalents and restricted cash, end of period	$ 705	$ 825	$ 896

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

NOTE 1. Organization and Nature of Operations

Pioneer Natural Resources Company ("Pioneer" or the "Company") is a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange. The Company is a large independent oil and gas exploration and production company that explores for, develops and produces oil, natural gas liquids ("NGLs") and gas in the Permian Basin in West Texas.

NOTE 2. Summary of Significant Accounting Policies

Principles of consolidation. The consolidated financial statements include the accounts of the Company and its wholly-owned and majority-owned subsidiaries since their acquisition or formation. All material intercompany balances and transactions have been eliminated. Certain reclassifications have been made to prior period amounts to conform to the current period's presentation.

Use of estimates in the preparation of financial statements. Preparation of the Company's consolidated financial statements in conformity with generally accepted accounting principles in the United States ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Depletion of oil and gas properties and impairment of proved and unproved oil and gas properties and goodwill, in part, is determined using estimates of proved, probable and possible oil and gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved, probable and possible reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves and commodity price outlooks. Actual results could differ from the estimates and assumptions utilized.

Cash and cash equivalents. The Company's cash and cash equivalents include depository accounts held by banks and marketable securities with original issuance maturities of 90 days or less.

Restricted cash. The Company's restricted cash includes funds held in escrow to cover future deficiency fee payments in connection with the Company's 2019 sale of its Eagle Ford assets and other remaining assets in South Texas (the "South Texas Divestiture"). Beginning in 2021, the required escrow balance declines and, to the extent there is any remaining balance after the payment of deficiency fees, the balance will become unrestricted and revert to the Company on March 31, 2023. Interest income related to restricted cash is recorded in interest and other income in the consolidated statements of operations.

Investments. Periodically, the Company invests in commercial paper and corporate bonds with investment grade rated entities. The Company also periodically enters into time deposits with financial institutions. Commercial paper and time deposits are included in cash and cash equivalents if they have maturity dates that are less than 90 days at the date of purchase; otherwise, investments are included in short-term investments or long-term investments in the consolidated balance sheets based on their maturity dates.

As of December 31, 2019, the Company has no investments classified as held-to-maturity. As of December 31, 2018, the Company's investments were carried at amortized cost and classified as held-to-maturity as the Company had the intent and ability to hold them until they mature. The carrying values of held-to-maturity investments were adjusted for amortization of premiums and accretion of discounts over the remaining life of the investment. Income related to these investments was recorded in interest and other income in the consolidated statements of operations.

Accounts receivable. The Company's accounts receivable – trade are primarily comprised of oil and gas sales receivables, joint interest receivables and other receivables for which the Company does not require collateral security. The Company's share of oil and gas production is sold to various purchasers who must be prequalified under the Company's credit risk policies and procedures. The Company records allowances for doubtful accounts based on the age of accounts receivables and the financial condition of its purchasers. The Company's credit risk related to collecting accounts receivables is mitigated by using credit and other financial criteria to evaluate the credit standing of the entity obligated to make payment on the accounts receivable, and where appropriate, the Company obtains assurances of payment, such as a guarantee by the parent company of the counterparty or other credit support.

The Company's allowance for doubtful accounts totaled $2 million for each of the years ended December 31, 2019 and 2018. The Company establishes allowances for bad debts equal to the estimable portions of accounts receivable for which failure to collect is considered probable. The Company estimates the portions of joint interest receivables for which failure to collect is probable based on percentages of joint interest receivables that are past due. The Company estimates the portions of other receivables for which failure to collect is probable based on the relevant facts and circumstances surrounding the receivable. Allowances for doubtful accounts are recorded as reductions to the carrying values of the receivables included in the Company's consolidated balance sheets and are recorded in other expense in the consolidated statements of operations in the accounting periods during which failure to collect an estimable portion is determined to be probable.

Inventories. The Company's inventories consist of materials, supplies and commodities. The Company's materials and supplies inventory is primarily comprised of oil and gas maintenance materials and repair parts, water, chemicals and other operating supplies. The materials and supplies inventory is primarily acquired for use in future drilling and production operations or repair operations and is carried at the lower of cost or market, on a weighted average cost basis. Valuation allowances for materials and supplies inventories are recorded as reductions to the carrying values of the materials and supplies inventories included in the Company's consolidated balance sheets and are recorded in other expense in the consolidated statements of operations.

Commodity inventories are carried at the lower of cost or market, on a first-in, first-out basis. The Company's commodity inventories consist of oil, NGLs and gas volumes held in storage or as linefill in pipelines. Any valuation allowances of commodity inventories are recorded as reductions to the carrying values of the commodity inventories included in the Company's consolidated balance sheets and as charges to other expense in the consolidated statements of operations.

The components of inventories are as follows:

	As of December 31,	
	2019	2018
	(in millions)	
Materials and supplies (a)	$ 75	$ 128
Commodities	130	114
Total inventories	$ 205	$ 242

(a) As of December 31, 2019 and 2018, the Company's materials and supplies inventories were net of valuation allowances of $2 million and $5 million, respectively.

Investment in affiliate. In December 2018, the Company completed the sale of its pressure pumping assets to ProPetro Holding Corp. ("ProPetro") in exchange for cash and 16.6 million shares of ProPetro's common stock, representing an ownership interest in ProPetro of 16 percent. Additionally, in October 2019, Phillip A. Gobe, a nonemployee member of the Company's board of directors, was appointed by the board of directors of ProPetro to serve as its Executive Chairman. Mark S. Berg, the Company's Executive Vice President, Corporate Operations, continues to serve as a member of the ProPetro board of directors under the Company's right to designate a director to the board of directors of ProPetro so long as the Company owns five percent or more of ProPetro's outstanding common stock. Based on the Company's ownership in ProPetro and representation on the ProPetro board of directors, ProPetro is considered an affiliate and deemed to be a related party. The Company uses the fair value option to account for its equity method investment in ProPetro with any changes in fair value recorded in interest and other income in the consolidated statements of operations. The carrying value of the Company's investment in ProPetro is included in investment in affiliate in the consolidated balance sheets. See Note 4 and Note 12 for additional information.

Oil and gas properties. The Company utilizes the successful efforts method of accounting for its oil and gas properties. Under this method, all costs associated with productive wells and nonproductive development wells are capitalized while nonproductive exploration costs and geological and geophysical expenditures are expensed. The Company capitalizes interest on expenditures for significant development projects, generally when the underlying project is sanctioned, until such projects are ready for their intended use.

The Company does not carry the costs of drilling an exploratory well as an asset in its consolidated balance sheets following the completion of drilling unless both of the following conditions are met: (i) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (ii) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Due to the capital-intensive nature and the geographical location of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production data in the area, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and are being pursued constantly. Consequently, the Company's assessment of suspended exploratory well costs is continuous until a decision can be made that the project has found sufficient proved reserves to sanction the project or is noncommercial and is charged to exploration and abandonments expense. See Note 6 for additional information.

As of December 31, 2019, the Company owns interests in 11 gas processing plants, including the related gathering systems. The Company's ownership interests in the gas processing plants are primarily to accommodate handling the Company's gas production and thus are considered a component of the capital and operating costs of the respective fields that they service. The operators of the plants process the Company's and third-party gas volumes for a fee. The Company's share of revenues and expenses derived from volumes processed through the plants and treating facilities are reported as components of oil and gas production costs. Revenues generated from the processing plants and treating facilities for the years ended December 31, 2019, 2018 and 2017 were $90 million, $78 million and $60 million, respectively. Expenses attributable to the processing plants and treating facilities for the same respective periods were $43 million, $36 million and $26 million. The capitalized costs of the plants and treating facilities are included in proved oil and gas properties and are depleted using the unit-of-production method along with the other capitalized costs of the field that they service.

The capitalized costs of proved properties are depleted using the unit-of-production method based on proved reserves. Costs of significant nonproducing properties, wells in the process of being drilled and development projects are excluded from depletion until the related project is completed and proved reserves are established or, if unsuccessful, impairment is recognized.

Proceeds from the sales of individual properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depletion, depreciation and amortization, if doing so does not materially impact the depletion rate of an amortization base. Generally, no gain or loss is recorded until an entire amortization base is sold. However, gain or loss is recorded from the sale of less than an entire amortization base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base.

The Company performs assessments of its long-lived assets to be held and used, including proved oil and gas properties accounted for under the successful efforts method of accounting, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows, including vertical integrated services that are used in the development of the assets, is less than the carrying amount of the assets, including the carrying value of vertical integrated services assets. In these circumstances, the Company recognizes an impairment charge for the amount by which the carrying amount of the assets exceeds the estimated fair value of the assets. Impairment charges for proved oil and gas properties are recorded in impairment of oil and gas properties in the consolidated statements of operations. See Note 4 for additional information.

Unproved oil and gas properties are periodically assessed for impairment on a project-by-project basis. These impairment assessments are affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. If the estimated future net cash flows attributable to such projects are not expected to be sufficient to fully recover the costs invested in each project, the Company will recognize an impairment charge at that time. Impairment charges for unproved oil and gas properties are recorded in exploration and abandonments in the consolidated statements of operations.

Goodwill. Goodwill is assessed for impairment whenever it is likely that events or circumstances indicate the carrying value of a reporting unit exceeds its fair value, but no less often than annually. An impairment charge is recorded for the amount by which the carrying amount exceeds the fair value of a reporting unit in the period it is determined to be impaired.

The Company performed its annual qualitative assessment of goodwill during the third quarter of 2019 to determine whether it was more likely than not that the fair value of the Company's reporting unit was less than its carrying amount. Based on the results of the assessment, the Company determined it was not likely that the carrying value of the Company's reporting unit exceeded its fair value.

Other property and equipment, net. Other property and equipment is recorded at cost. The carrying values of other property and equipment, net of accumulated depreciation of $382 million and $854 million as of December 31, 2019 and 2018, respectively, are as follows:

	As of December 31,	
	2019	2018
	(in millions)	
Land and buildings (a)	$ 877	$ 380
Water infrastructure (b)	404	343
Construction-in-progress and capitalized interest (c)	152	311
Information technology	120	143
Transport and field equipment (d)	35	50
Furniture and fixtures	28	15
Proved and unproved sand properties (e)	16	36
Leasehold improvements	—	13
Total other property and equipment, net	$ 1,632	$ 1,291

(a) Includes land, buildings, any related improvements to land and buildings, and a finance lease entered into by the Company for its new corporate headquarters in Irving, Texas. See Note 10 for additional information.
(b) Includes costs for pipeline infrastructure and water supply wells.
(c) Includes capitalized costs and capitalized interest on other property and equipment not yet placed in service.
(d) Includes vehicles and well servicing equipment, including pulling units, fracture stimulation tanks, water transport trucks, hot oilers, construction equipment and fishing tools, that are used on Company-operated properties.
(e) Includes sand mines, facilities and unproved leaseholds that primarily provide the Company with proppant for use in the fracture stimulation of oil and gas wells.

Other property and equipment is depreciated over its estimated useful life on a straight-line basis. Buildings are generally depreciated over 20 to 39 years. Equipment, vehicles, furniture and fixtures and information technology assets are generally depreciated over three to 10 years. Water infrastructure is generally depreciated over three to 50 years. Leasehold improvements are amortized over the lesser of their estimated useful lives or the underlying terms of the associated leases.

The Company reviews its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If such assets are considered to be impaired, the impairment to be recorded is measured by the amount by which the carrying amount of the asset exceeds its estimated fair value. The estimated fair value is determined using either a discounted future cash flow model or another appropriate fair value method.

Leases. The Company enters into leases for drilling rigs, storage tanks, equipment and buildings and recognizes lease expense on a straight-line basis over the lease term. Lease right-of-use assets and liabilities are initially recorded on the lease commencement date based on the present value of lease payments over the lease term. As most of the Company's lease contracts do not provide an implicit discount rate, the Company uses its incremental borrowing rate, which is determined based on information available at the commencement date of a lease. Leases may include renewal, purchase or termination options that can extend or shorten the term of the lease. The exercise of those options is at the Company’s sole discretion and is evaluated at inception and throughout the contract to determine if a modification of the lease term is required. Leases with an initial term of 12 months or less are not recorded as a lease right-of-use asset and liability. See Note 10 for additional information.

Asset retirement obligations. The Company records a liability for the fair value of an asset retirement obligation in the period in which the associated asset is acquired or placed into service, if a reasonable estimate of fair value can be made. Asset retirement obligations are generally capitalized as part of the carrying value of the long-lived asset to which it relates. Conditional asset retirement obligations meet the definition of liabilities and are recorded when incurred and when fair value can be reasonably estimated.

The Company includes the current and noncurrent portions of asset retirement obligations in other current liabilities and other liabilities, respectively, in the consolidated balance sheets and expenditures are included as cash used in operating activities in the consolidated statements of cash flows. See Note 9 for additional information.

Treasury stock. Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares held is reduced by the average purchase price per share of the aggregate treasury shares held.

Revenue recognition. On January 1, 2018, the Company adopted Accounting Standards Codification ("ASC") 606, "Revenue from Contracts with Customers," ("ASC 606") using the modified retrospective transition method. The adoption did not require an adjustment to retained earnings as there was no material change to the timing or pattern of revenue recognition due to the adoption of ASC 606. The Company recognizes revenue when control of the promised goods or services is transferred to customers at an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services.

Oil sales. Sales under the Company's oil contracts are generally considered performed when the Company sells oil production at the wellhead and receives an agreed-upon index price, net of any price differentials. The Company recognizes the sales revenue when (i) control/custody transfers to the purchaser at the wellhead and (ii) the net price is fixed and determinable.

NGL and gas sales. Under the majority of the Company’s gas processing contracts, gas is delivered to a midstream processing entity and the Company elects to take residue gas and NGLs in-kind at the tailgate. The Company recognizes revenue when the products are delivered (custody transfer) to the ultimate third-party purchaser at a contractually agreed-upon delivery point at a specified index price.

Sales of purchased oil and gas. The Company enters into purchase transactions with third parties and separate sale transactions with third parties to diversify a portion of the Company's West Texas Intermediate oil ("WTI") and gas sales to Gulf Coast refineries and LNG facilities, international export markets and to satisfy unused gas pipeline capacity commitments. Revenues and expenses from these transactions are presented on a gross basis as the Company acts as a principal in the transaction by assuming both the risk and rewards of ownership, including credit risk, of the commodities purchased and the responsibility to deliver the commodities sold. Transportation costs associated with these transactions are presented on a net basis in purchased oil and gas expense. Firm transportation payments on excess pipeline capacity are recorded as other expense in the consolidated statements of operations.

See Note 14 and Note 16 for additional information.

Derivatives. All of the Company's derivatives are accounted for as non-hedge derivatives and are recorded at estimated fair value in the consolidated balance sheets. All changes in the fair values of its derivative contracts are recorded as gains or losses in the earnings of the periods in which they occur. The Company enters into derivatives under master netting arrangements, which, in an event of default, allows the Company to offset payables to and receivables from the defaulting counterparty. The Company classifies the fair value amounts of derivative assets and liabilities executed under master netting arrangements as net current or noncurrent derivative assets or net current or noncurrent derivative liabilities, whichever the case may be, by commodity and counterparty.

Net derivative asset values are determined, in part, by utilization of the derivative counterparties' credit-adjusted risk-free rate curves and net derivative liabilities are determined, in part, by utilization of the Company's credit-adjusted risk-free rate curve. The credit-adjusted risk-free rate curves for the Company and the counterparties are based on their independent market-quoted credit default swap rate curves plus the United States Treasury Bill yield curve as of the valuation date.

The Company's credit risk related to derivatives is a counterparty's failure to perform under derivative contracts owed to the Company. The Company uses credit and other financial criteria to evaluate the credit standing of, and to select, counterparties to its derivative instruments. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative instruments, associated credit risk is mitigated by the Company's credit risk policies and procedures.

The Company has entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of its derivative counterparties. The terms of the ISDA Agreements provide the Company and the counterparties with rights of set off upon the occurrence of defined acts of default by either the Company or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note 5 for additional information.

Income taxes. The provision for income taxes is determined using the asset and liability approach of accounting for income taxes. Under this approach, deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and net operating loss and tax credit carryforwards. The amount of deferred taxes on these temporary differences is determined using the tax rates that are expected to apply to the period when the asset is realized or the liability is settled, as applicable, based on tax rates and laws in the respective tax jurisdiction enacted as of the balance sheet date.

The Company reviews its deferred tax assets for recoverability and establishes a valuation allowance based on projected future taxable income, applicable tax strategies and the expected timing of the reversals of existing temporary differences. A valuation allowance is provided when it is more likely than not (likelihood of greater than 50 percent) that some portion or all of the deferred tax assets will not be realized.

The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based upon the technical merits of the position. If all or a portion of the unrecognized tax benefit is sustained upon examination by the taxing authorities, the tax benefit will be recognized as a reduction to the Company's deferred tax liability and will affect the Company's effective tax rate in the period it is recognized. See Note 17 for additional information.

The Company records any tax-related interest charges as interest expense and any tax-related penalties as other expense in the consolidated statements of operations.

Stock-based compensation. Stock-based compensation expense for restricted stock, restricted stock units and performance units expected to be settled in the Company's common stock ("Equity Awards") is measured at the grant date or modification date, as applicable, using the fair value of the award, and is recorded, net of estimated forfeitures, on a straight line basis over the requisite service period of the respective award. The fair value of Equity Awards, except performance unit awards, is determined on the grant date or modification date, as applicable, using the prior day's closing stock price. The fair value of performance unit awards is determined using the Monte Carlo simulation model.

Equity Awards are net settled by withholding shares of the Company's common stock to satisfy income tax withholding payments due upon vesting. Remaining vested shares are remitted to individual employee brokerage accounts. Shares to be delivered upon vesting of Equity Awards are made available from authorized, but unissued shares or shares held as treasury stock.

Restricted stock awards expected to be settled in cash on their vesting dates, rather than in common stock ("Liability Awards"), are included in accounts payable – due to affiliates in the consolidated balance sheets. The fair value of Liability Awards is determined on the grant date using the prior day's closing stock price. The Company recognizes the value of Liability Awards on a straight line basis over the requisite service period of the award. Liability Awards are marked to fair value as of each balance sheet date using the closing stock price on the balance sheet date. Changes in the fair value of Liability Awards are recorded as increases or decreases to stock-based compensation expense.

Equity Awards and Liability awards participate in dividends during vesting periods and generally vest over three years.

Segments. Based upon how the Company is organized and managed, the Company has one reportable operating segment, which is oil and gas development, exploration and production. The Company considers its vertical integration services as ancillary to its oil and gas development, exploration and producing activities and manages these services to support such activities. In addition, the Company has a single, company-wide management team that allocates capital resources to maximize profitability and measures financial performance as a single enterprise.

Adoption of new accounting standards. In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-02, "Leases (Topic 842)" ("ASC 842"), which supersedes the lease recognition requirements in ASC 840, "Leases" ("ASC 840"), and requires lessees to recognize lease assets and lease liabilities for those leases previously classified as operating leases. The Company adopted ASC 842 as of January 1, 2019 using the modified retrospective transition method. The Company elected to apply the transition guidance under ASU 2018-11, "Leases (Topic 842) Targeted Improvements," in which ASC 842 is applied at the adoption date, while the comparative periods will continue to be reported in accordance with historic accounting under ASC 840. This standard does not apply to leases to explore for or use minerals, oil or gas resources, including the right to explore for those natural resources and rights to use the land in which those natural resources are contained.

ASC 842 allowed for the election of certain practical expedients at adoption to ease the burden of implementation. At implementation, the Company elected to (i) maintain the historical lease classification for leases prior to January 1, 2019, (ii) maintain the historical accounting treatment for land easements that existed at adoption, (iii) use historical practices in assessing the lease term of existing contracts at adoption, (iv) combine lease and non-lease components of a contract as a single lease and (v) not record short-term leases in the consolidated balance sheet, all in accordance with ASC 842.

The adoption of ASC 842 did not have a material impact on the consolidated statements of operations and had no impact on the Company's cash flows. The Company did not record a change to its opening retained earnings as of January 1, 2019, as there was no material change to the timing or pattern of recognition of lease costs due to the adoption of ASC 842.

New accounting pronouncements. In June 2016, the FASB issued ASU 2016-13, "Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments" ("ASU 2016-13"). ASU 2016-13 changes the impairment model for most financial assets and certain other instruments, including trade and other receivables, and requires entities to use a new forward-looking expected loss model that will result in the earlier recognition of allowances for losses. This update is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, with early adoption permitted. Entities will use the modified retrospective approach to apply the standard's provisions and record a cumulative-effect adjustment to retained earnings for additional receivable loss allowances, if any, as of the beginning of the first reporting period in which the guidance is adopted. While the Company continues to prepare for the adoption of ASU 2016-13 on January 1, 2020, the Company does not expect that it will have a material impact on its consolidated financial statements.

NOTE 3. Acquisitions, Divestitures, Decommissioning and Restructuring Activities

Acquisitions. During 2019, 2018 and 2017, the Company spent a total of $28 million, $65 million and $136 million, respectively, to acquire primarily undeveloped acreage for future exploitation and exploration activities in the Spraberry/Wolfcamp field of the Permian Basin.

Divestitures. The Company's significant divestitures are as follows:

- In December 2019, the Company completed the sale of certain vertical and horizontal wells and approximately 4,500 undeveloped acres in Glasscock County of the Permian Basin to an unaffiliated third party for net cash proceeds of $64 million. The Company recorded a gain of $10 million associated with the sale.
- In July 2019, the Company completed the sale of certain vertical wells and approximately 1,400 undeveloped acres in Martin County of the Permian Basin to an unaffiliated third party for net cash proceeds of $27 million. The Company recorded a gain of $26 million associated with the sale.
- In June 2019, the Company completed the sale of certain vertical wells and approximately 1,900 undeveloped acres in Martin County of the Permian Basin to an unaffiliated third party for net cash proceeds of $38 million. The Company recorded a gain of $31 million associated with the sale.
- In May 2019, the Company completed the South Texas Divestiture to an unaffiliated third party in exchange for total consideration having an estimated fair value of $210 million. The fair value of the consideration included (i) net cash proceeds of $2 million, (ii) $136 million in contingent consideration and (iii) a $72 million receivable associated with estimated deficiency fees to be paid by the buyer. Of the total consideration, $208 million is considered a noncash investing activity for the year December 31, 2019. The Company recorded a loss of $525 million and recognized employee-related charges of $19 million associated with the sale.

  Contingent Consideration. Per the terms of the purchase and sale agreement, the Company is entitled to receive contingent consideration of up to $450 million based on future annual oil and NGL prices during each of the years from 2020 to 2024. The Company determined the fair value of the contingent consideration as of the date of the sale to be $136 million using an option pricing model. The contingent consideration is included in noncurrent other assets in the consolidated balance sheets. The Company revalues the contingent consideration each reporting period and records the resulting valuation changes in interest and other income in the consolidated statements of operations. See Note 4, Note 5 and Note 15 for additional information.

  Deficiency Fee Obligation. The Company transferred its long-term midstream agreements and associated minimum volume commitments ("MVC") to the buyer. However, the Company retained the obligation to pay 100 percent of any deficiency fees associated with the MVC from January 2019 through July 2022. The Company determined the fair value of the deficiency fee obligation as of the date of the sale to be $348 million using a probability weighted present value model. The deficiency fee obligation is included in current or noncurrent liabilities in the consolidated balance sheets based on the forecasted timing of payments. See Note 4 for additional information.

Deficiency Fee Receivable. The buyer is required to reimburse the Company for up to 20 percent of the deficiency fees paid under the transferred midstream agreements from January 2019 through July 2022. Such reimbursement will be paid by the buyer in installments beginning in 2023 through 2025. The Company determined the fair value of the deficiency fee receivable as of the date of the sale to be $72 million using a credit risk-adjusted valuation model. The deficiency fee receivable is included in noncurrent other assets in the consolidated balance sheets. See Note 4 and Note 11 for additional information.

Restricted Cash. As of the date of the sale, the Company deposited $75 million into an escrow account to be used to fund future deficiency fee payments. Beginning in 2021, the required escrow balance will decline to $50 million and, to the extent that there is any remaining balance after the payment of deficiency fees, the balance will become unrestricted and revert to the Company on March 31, 2023.

- In December 2018, the Company completed the sale of its pressure pumping assets to ProPetro in exchange for total consideration of $282 million, comprised of 16.6 million shares of ProPetro's common stock, which was delivered as of the date of the sale and had a fair value of $172 million, and $110 million in cash, which was received during the first quarter of 2019. During 2018, the Company recorded a gain of $30 million, employee-related charges of $19 million, contract termination charges of $13 million and other divestiture-related charges of $6 million associated with the sale. During 2019, the Company reduced the gain associated with the sale by $10 million and recorded additional employee-related charges of $1 million. See Note 12 for additional information.

- In December 2018, the Company completed the sale of approximately 2,900 net acres in the Sinor Nest (Lower Wilcox) oil field in South Texas to an unaffiliated third party for net cash proceeds of $105 million. During 2018, the Company recorded a gain of $54 million associated with the sale.

- In August 2018, the Company completed the sale of its assets in the West Panhandle gas and liquids field to an unaffiliated third party for net cash proceeds of $170 million. During 2018, the Company recorded a gain of $127 million and employee-related charges of $7 million associated with the sale.

- In July 2018, the Company completed the sale of its gas field assets in the Raton Basin to an unaffiliated third party for net cash proceeds of $54 million. The Company recorded a noncash impairment charge of $77 million in June 2018 to reduce the carrying value of its Raton Basin assets to their estimated fair value less costs to sell as the assets were considered held for sale. During 2018, the Company recorded a gain of $2 million, other divestiture-related charges of $117 million, including $111 million of deficiency charges related to certain firm transportation contracts retained by the Company and employee-related charges of $6 million associated with the sale.

- In April 2018, the Company completed the sale of approximately 10,200 net acres in the West Eagle Ford Shale gas and liquids field to an unaffiliated third party for net cash proceeds of $100 million. During 2018, the Company recorded a gain of $75 million associated with the sale.

- In April 2017, the Company completed the sale of approximately 20,500 acres in the Martin County region of the Permian Basin to an unaffiliated third party for net cash proceeds of $264 million. During 2017, the Company recorded a gain of $194 million associated with the sale.

- *Other.* During 2019, 2018 and 2017, the Company sold other proved and unproved properties, inventory and other property and equipment and recorded a net loss of $9 million, and net gains of $1 million and $14 million, respectively. The net gain of $14 million for 2017 is primarily related to the sale of nonstrategic proved and unproved properties in the Permian Basin for cash proceeds of $77 million.

Decommissioning. In November 2018, the Company announced plans to close its sand mine located in Brady, Texas and transition its proppant supply requirements to West Texas sand sources. During 2018, the Company recorded $443 million of accelerated depreciation and $7 million of employee-related charges associated with the pending shutdown. During 2019, the Company recorded $23 million of accelerated depreciation, $13 million of inventory and other property and equipment impairment charges and $12 million of sand mine closure-related costs.

Restructuring. During 2019, the Company implemented a corporate restructuring program to align its cost structure with the needs of a Permian Basin-focused company, which resulted in an approximately 25 percent employee reduction. The restructuring occurred in three phases (collectively, the "Corporate Restructuring Program") as follows:

- In March 2019, the Company made certain changes to its leadership and organizational structure, which included the early retirement and departure of certain officers of the Company.
- In April 2019, the Company adopted a voluntary separation program ("VSP") for certain eligible employees, and
- In May 2019, the Company implemented an involuntary separation program ("ISP").

During 2019, the Company recorded $159 million of employee-related charges associated with the Corporate Restructuring Program, including $26 million of noncash stock-based compensation expense related to the accelerated vesting of certain equity awards. See Note 8 and Note 16 for additional information.

Employee-related costs are primarily recorded in other expense in the consolidated statements of operations. Obligations associated with employee-related charges are included in accounts payable - due to affiliates in the consolidated balance sheets.

The changes in employee-related obligations are as follows:

	Year Ended December 31,	
	2019	2018
	(in millions)	
Beginning employee-related obligations	$ 27	$ —
Additions (a)	155	39
Cash payments	(176)	(12)
Ending employee-related obligations	$ 6	$ 27

(a) Additions for the year ended December 31, 2019 primarily include $133 million of charges related to the Corporate Restructuring Program and $19 million of charges related primarily to the South Texas Divestiture. For the year ended December 31, 2018, additions primarily relate to the 2018 divestitures.

NOTE 4. Fair Value Measurements

The Company determines fair value based on the price that would be received from selling an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements are based upon inputs that market participants use in pricing an asset or liability, which are characterized according to a hierarchy that prioritizes those inputs based on the degree to which they are observable. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. The fair value input hierarchy level to which an asset or liability measurement in its entirety falls is determined based on the lowest level input that is significant to the measurement in its entirety.

The three input levels of the fair value hierarchy are as follows:

- Level 1 – quoted prices for identical assets or liabilities in active markets.
- Level 2 – quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; inputs other than quoted prices that are observable for the asset or liability (e.g. interest rates) and inputs derived principally from or corroborated by observable market data by correlation or other means.

- Level 3 – unobservable inputs for the asset or liability, typically reflecting management's estimate of assumptions that market participants would use in pricing the asset or liability. The fair values are therefore determined using model-based techniques, including discounted cash flow models.

Assets and liabilities measured at fair value on a recurring basis. Assets and liabilities measured at fair value on a recurring basis are as follows:

	As of December 31, 2019			
	Fair Value Measurements			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Commodity derivatives	$ —	$ 32	$ —	$ 32
Deferred compensation plan assets	85	—	—	85
Investment in affiliate	187	—	—	187
Contingent consideration	—	91	—	91
Total assets	272	123	—	395
Liabilities:				
Commodity derivatives	—	20	—	20
Total recurring fair value measurements	$ 272	$ 103	$ —	$ 375

	As of December 31, 2018			
	Fair Value Measurements			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Commodity derivatives	$ —	$ 52	$ —	$ 52
Deferred compensation plan assets	82	—	—	82
Investment in affiliate	—	172	—	172
Total assets	82	224	—	306
Liabilities:				
Commodity derivatives	—	27	—	27
Total recurring fair value measurements	$ 82	$ 197	$ —	$ 279

Commodity price derivatives. The Company's commodity derivatives primarily represent oil, NGL and gas swap contracts, collar contracts, collar contracts with short puts and basis swap contracts. The asset and liability measurements for the Company's commodity derivative contracts are determined using Level 2 inputs. The Company utilizes discounted cash flow and option-pricing models for valuing its commodity price derivatives.

The asset and liability values attributable to the Company's commodity price derivatives were determined based on inputs that include (i) the contracted notional volumes, (ii) independent active market price quotes, (iii) the applicable estimated credit-adjusted risk-free rate yield curve and (iv) the implied rate of volatility inherent in the collar contracts and collar contracts with short puts, which is based on active and independent market-quoted volatility factors.

Deferred compensation plan assets. The Company's deferred compensation plan assets include investments in equity and mutual fund securities that are actively traded on major exchanges. The fair value of these investments is determined using Level 1 inputs based on observable prices on major exchanges.

Investment in affiliate. The Company elected the fair value option for measuring its equity method investment in ProPetro. The fair value of its investment in ProPetro is determined using Level 1 inputs based on observable prices on a major exchange. As of December 31, 2018, the fair value of the Company's investment in ProPetro was determined using Level 2 inputs, including the quoted market price for the stock adjusted to reflect a value discount due to restrictions on the Company's ability to sell the investment prior to July 1, 2019. See Note 12 and Note 15 for additional information.

Contingent consideration. The Company has a right to receive contingent consideration in conjunction with the South Texas Divestiture of up to $450 million based on future oil and NGL prices during each of the years from 2020 to 2024. The fair value of the contingent consideration is determined using Level 2 inputs based on an option pricing model using quoted future commodity prices from active markets, implied volatility factors and counterparty credit risk assessments. See Note 3 and Note 5 for additional information.

Assets and liabilities measured at fair value on a nonrecurring basis. Certain assets and liabilities are measured at fair value on a nonrecurring basis. These assets and liabilities are not measured at fair value on an ongoing basis and are subject to fair value adjustments in certain circumstances. These assets and liabilities can include inventory, proved and unproved oil and gas properties and other long-lived assets that are written down to fair value when they are impaired or held for sale.

Other assets. During the year ended December 31, 2019, the Company impaired the remaining $13 million of inventory and other property and equipment related to the decommissioning of the Company's Brady, Texas sand mine, as these assets had no remaining future economic value. In addition, the Company recognized a $16 million impairment charge related to pressure pumping assets that had no future benefit to the Company. See Note 16 for additional information.

South Texas Divestiture. The Company recorded a deficiency fee obligation and related deficiency fee receivable in conjunction with the South Texas Divestiture. The fair value of the deficiency fee obligation and deficiency fee receivable was determined using Level 3 inputs based on a probability-weighted forecast that considers historical results, market conditions and various development plans to arrive at the estimated present value of the deficiency payments and corresponding receipts. The present value of the future cash payments and expected cash receipts were determined using a 2.9 percent and 3.2 percent discount rate, respectively, based on the estimated timing of future payments and receipts and the Company's counterparty credit risk assessments. See Note 3 and Note 11 for additional information.

Proved oil and gas properties. As a result of the the Company's proved property impairment assessments, the Company recorded noncash impairment charges to reduce the carrying values of its Raton Basin gas field assets during the year ended December 31, 2017. Impairment charges for proved oil and gas properties are recorded as impairment of oil and gas properties in the consolidated statements of operations.

The Company calculated the fair value of the Raton Basin gas field assets using a discounted cash flow model. Level 3 inputs used to calculate the discounted future cash flows included management's longer-term commodity price outlooks ("Management's Price Outlooks") and management's outlooks for (i) production, (ii) capital expenditures, (iii) production costs and (iv) estimated proved reserves and risk-adjusted probable reserves. Management's Price Outlooks are developed based on third-party longer-term commodity futures price outlooks as of each measurement date. The expected future net cash flows were discounted using an annual rate of ten percent to determine fair value.

The fair value and fair value adjustments for proved properties, as well as the average oil price per barrel ("Bbl") and gas price per British thermal unit ("MMBtu") utilized in the respective Management's Price Outlooks are as follows:

		Fair Value	Fair Value Adjustment	Management's Price Outlooks	
				Oil	Gas
		(in millions)			
Raton Basin	March 2017	$ 186	$ (285)	$ 53.65	$ 3.00

Sale of Raton Basin assets. In June 2018, the Company recognized impairment charges of $77 million to reduce the carrying value of its Raton Basin gas field assets to the agreed upon sales price for these assets, which were sold in July 2018. The impairment charges included $65 million attributable to proved oil and gas properties and $12 million of other property and equipment. The Company also recorded other divestiture-related charges of $111 million attributable to deficiency charges related to certain firm transportation contracts retained by the Company. The fair value of these contracts was determined using Level 2 inputs, including an annual discount rate of 4.4 percent, to discount the expected future cash flows. See Note 3 for additional information.

Financial instruments not carried at fair value. Carrying values and fair values of financial instruments that are not carried at fair value in the consolidated balance sheets are as follows:

	As of December 31, 2019		As of December 31, 2018	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in millions)			
Assets:				
Cash and cash equivalents:				
Cash (a)	$ 631	$ 631	$ 775	$ 775
Time deposits (a)	—	—	50	50
Total	$ 631	$ 631	$ 825	$ 825
Restricted cash (a)	$ 74	$ 74	$ —	$ —
Short-term investments:				
Commercial paper (b)	$ —	$ —	$ 53	$ 53
Corporate bonds (c)	—	—	290	288
Time deposits (b)	—	—	100	100
Total	$ —	$ —	$ 443	$ 441
Long-term investments:				
Corporate bonds (c)	$ —	$ —	$ 125	$ 125
Liabilities:				
Current portion of long-term debt (d)	$ 450	$ 451	$ —	$ —
Long-term debt (d)	$ 1,839	$ 1,995	$ 2,284	$ 2,374

(a) Fair value approximates carrying value due to the short-term nature of the instruments.
(b) Fair value is determined using Level 2 inputs.
(c) Fair value is determined using Level 1 inputs.
(d) Fair value is determined using Level 2 inputs. The Company's senior notes are quoted but not actively traded on major exchanges; therefore, fair value is based on periodic values as quoted on major exchanges.

The Company has other financial instruments consisting primarily of receivables, payables and other current assets and liabilities that approximate fair value due to the nature of the instrument and their relatively short maturities. Non-financial assets and liabilities initially measured at fair value include assets acquired and liabilities assumed in a business combination, goodwill and asset retirement obligations.

NOTE 5. Derivative Financial Instruments

The Company primarily utilizes commodity swap contracts, collar contracts, collar contracts with short puts and basis swap contracts to (i) reduce the effect of price volatility on the commodities the Company produces and sells or consumes, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. The Company also, from time to time, utilizes interest rate contracts to reduce the effect of interest rate volatility on the Company's indebtedness.

Oil production derivatives. The Company sells its oil production at the lease and the sales contracts governing such oil production are tied directly to, or are correlated with, New York Mercantile Exchange ("NYMEX") West Texas Intermediate ("WTI") oil prices. The Company also enters into pipeline capacity commitments in order to secure available oil, NGL and gas transportation capacity from the Company's areas of production. To diversify the oil prices it receives, the Company enters into purchase transactions with third parties and separate sale transactions with third parties for a portion of the Company's oil sales to Gulf Coast refineries or international export markets at prices that are highly correlated with Brent oil prices. As a result, the Company will generally use Brent derivative contracts to manage future oil price volatility.

Volumes per day associated with outstanding oil derivative contracts as of December 31, 2019 and the weighted average oil prices for those contracts are as follows:

	2020 First Quarter	2020 Second Quarter	2020 Third Quarter	2020 Fourth Quarter	Year Ending December 31, 2021
Brent swap contracts:					
Volume per day (Bbl)	3,407	—	—	—	—
Price per Bbl	$ 60.86	$ —	$ —	$ —	$ —
Brent collar contracts with short puts:					
Volume per day (Bbl)	145,500	135,500	115,500	115,500	7,000
Price per Bbl:					
Ceiling	$ 68.46	$ 68.84	$ 69.78	$ 69.78	$ 65.37
Floor	$ 61.64	$ 61.76	$ 62.06	$ 62.06	$ 60.00
Short put	$ 53.45	$ 53.48	$ 53.56	$ 53.56	$ 52.00
Brent call contracts sold:					
Volume per day (Bbl) (a)	—	—	—	—	13,000
Price per Bbl:	$ —	$ —	$ —	$ —	$ 72.10

(a) The referenced call contracts were sold in exchange for higher ceiling prices on certain 2020 collar contracts with short puts.

NGL production derivatives. All material physical sales contracts governing the Company's NGL production are tied directly or indirectly to Mont Belvieu, Texas NGL component product prices. The Company uses derivative contracts to manage the NGL component product price volatility. As of December 31, 2019 the Company did not have any NGL derivative contracts outstanding.

Gas production derivatives. All material physical sales contracts governing the Company's gas production are tied directly or indirectly to NYMEX Henry Hub ("HH") gas prices or regional index prices where the gas is sold. The Company uses derivative contracts to manage gas price volatility and basis swap contracts to reduce basis risk between HH prices and actual index prices at which the gas is sold.

Volumes per day associated with outstanding gas derivative contracts as of December 31, 2019 and the weighted average gas prices for those contracts are as follows:

	2020 First Quarter	2020 Second Quarter	2020 Third Quarter	2020 Fourth Quarter
Swap contracts:				
Volume per day (MMBtu) (a)	—	30,000	30,000	10,109
Price per MMBtu	$ —	$ 2.41	$ 2.41	$ 2.41
Basis swap contracts:				
Permian Basin index swap volume per day (MMBtu) (a) (b)	—	30,000	30,000	10,109
Price differential ($/MMBtu)	$ —	$ (1.68)	$ (1.68)	$ (1.68)

(a) Between January 1, 2020 and February 18, 2020, the Company entered into additional (i) swap contracts for 10,000 MMBtu per day of November 2020 through March 2021 production at an average fixed price of $2.46 per MMBtu and (ii) basis swap contracts of 10,000 MMbtu per day of November 2020 through March 2021 production with an average price differential of $1.46 per MMBtu.
(b) The referenced basis swap contracts fix the basis differentials between the index price at which the Company sells its Permian Basin gas and the NYMEX index prices used in swap contracts.

Interest rate derivatives. The Company had no interest rate derivative contracts outstanding as of December 31, 2019, however, between January 1, 2020 and February 18, 2020, the Company entered into interest rate derivative contracts whereby the Company will receive a fixed five-year average treasury rate of 1.39% on a notional amount of $100 million and a fixed 10-year average treasury rate of 1.57% on a notional amount of $300 million.

Contingent consideration. The Company's right to receive contingent consideration in conjunction with the South Texas Divestiture was determined to be a derivative financial instrument that is not designated as a hedging instrument. The contingent consideration of up to $450 million is based on oil and NGL prices during each of the years from 2020 to 2024. See Note 3 and Note 4 for additional information.

Fair value. The fair value of derivative financial instruments not designated as hedging instruments is as follows:

As of December 31, 2019

Type	Consolidated Balance Sheet Location	Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Net Fair Value Presented in the Consolidated Balance Sheet
			(in millions)	
Assets:				
Commodity price derivatives	Derivatives - current	$ 32	$ —	$ 32
Contingent consideration	Other assets - noncurrent	$ 91	$ —	$ 91
Liabilities:				
Commodity price derivatives	Derivatives - current	$ 12	$ —	$ 12
Commodity price derivatives	Derivatives - noncurrent	$ 8	$ —	$ 8

As of December 31, 2018

Type	Consolidated Balance Sheet Location	Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Net Fair Value Presented in the Consolidated Balance Sheet
			(in millions)	
Assets:				
Commodity price derivatives	Derivatives - current	$ 59	$ (7)	$ 52
Liabilities:				
Commodity price derivatives	Derivatives - current	$ 34	$ (7)	$ 27

Gains and losses recorded on derivative contracts are as follows:

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) Recognized in Earnings on Derivatives	Year Ended December 31,		
		2019	2018	2017
			(in millions)	
Commodity price derivatives	Derivative gain (loss), net	$ 34	$ (292)	$ (99)
Interest rate derivatives	Derivative gain (loss), net	$ —	$ —	$ (1)
Contingent consideration	Interest and other income	$ (45)	$ —	$ —

The Company uses credit and other financial criteria to evaluate the credit standing of, and to select, counterparties to its derivative instruments. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative instruments, associated credit risk is mitigated by the Company's credit risk policies and procedures.

Net derivative assets (liabilities) associated with the Company's open commodity derivatives by counterparty are as follows:

	As of December 31, 2019
	(in millions)
Wells Fargo Bank	$ 15
JP Morgan Chase	5
Scotia Bank	3
Royal Bank of Canada	1
Bank of Montreal	(1)
J Aron & Company	(1)
Merrill Lynch	(1)
Nextera Energy Power Marketing	(2)
Citibank	(7)
	$ 12

See Note 2 for additional information.

NOTE 6. Exploratory Well Costs

The Company capitalizes exploratory well and project costs until a determination is made that the well or project has either found proved reserves, is impaired or is sold. The Company's capitalized exploratory well and project costs are included in proved properties in the consolidated balance sheets. If the exploratory well or project is determined to be impaired, the impaired costs are recorded as exploration and abandonments expense.

Capitalized exploratory well project activity is as follows:

	Year Ended December 31,	
	2019	2018
	(in millions)	
Beginning capitalized exploratory well costs	$ 509	$ 505
Additions to exploratory well costs pending the determination of proved reserves	2,172	2,585
Reclassification due to determination of proved reserves	(2,011)	(2,557)
Disposition of assets	(6)	(1)
Exploratory well costs charged to exploration and abandonment expense	(4)	(23)
Ending capitalized exploratory well costs	$ 660	$ 509

Aging of capitalized exploratory costs and the number of projects for which exploratory well costs have been capitalized for a period greater than one year, based on the date drilling was completed, are as follows:

	As of December 31,		
	2019	2018	2017
	(in millions, except well counts)		
Capitalized exploratory well costs that have been suspended:			
One year or less	$ 660	$ 509	$ 493
More than one year	—	—	12
	$ 660	$ 509	$ 505
Number of projects with exploratory well costs that have been suspended for a period greater than one year	—	—	7

NOTE 7. Long-term Debt and Interest Expense

The components of long-term debt, including the effects of issuance costs and issuance discounts, are as follows:

	As of December 31,	
	2019	2018
	(in millions)	
Outstanding debt principal balances:		
7.50% senior notes due 2020	$ 450	$ 450
3.45% senior notes due 2021	500	500
3.95% senior notes due 2022	600	600
4.45% senior notes due 2026	500	500
7.20% senior notes due 2028	250	250
	2,300	2,300
Issuance costs and discounts	(11)	(16)
Total debt	2,289	2,284
Less current portion of long-term debt	450	—
Long-term debt	$ 1,839	$ 2,284

Credit facility. The Company's long-term debt consists of senior notes, a revolving corporate credit facility (the "Credit Facility") and the effects of issuance costs and discounts. The Credit Facility is maintained with a syndicate of financial institutions (the "Syndicate") and has aggregate loan commitments of $1.5 billion. The Credit Facility has a maturity date of October 2023. As of December 31, 2019, the Company had no outstanding borrowings under the Credit Facility and was in compliance with its debt covenants.

Borrowings under the Credit Facility may be in the form of revolving loans or swing line loans. Revolving loans represent loans made ratably by the Syndicate in accordance with their respective commitments under the Credit Facility and bear interest, at the option of the Company, based on (a) a rate per annum equal to the higher of the prime rate announced from time to time by Wells Fargo Bank, National Association or the weighted average of the rates on overnight federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 0.5 percent plus a defined alternate base rate spread margin, which is currently 0.25 percent based upon the Company's debt rating or (b) a base Eurodollar rate, plus a margin (the "Applicable Margin"), which is currently 1.25 percent and is also determined by the Company's debt rating. Swing line loans represent loans made by a subset of the lenders in the Syndicate and may not exceed $150 million. Swing line loans under the Credit Facility bear interest at a rate per annum equal to the "ASK" rate for federal funds periodically published by the Dow Jones Market Service plus the Applicable Margin. Letters of credit outstanding under the Credit Facility are subject to a per annum fee, representing the Applicable Margin plus 0.125 percent. The Company also pays commitment fees on undrawn amounts under the Credit Facility that are determined by the Company's debt rating (currently 0.15 percent). Borrowings under the Credit Facility are general unsecured obligations.

The Credit Facility requires the maintenance of a ratio of total debt to book capitalization, subject to certain adjustments, not to exceed 0.65 to 1.0. As of December 31, 2019, the Company was in compliance with all of its debt covenants.

Senior notes. The Company's senior notes are general unsecured obligations ranking equally in right of payment with all other senior unsecured indebtedness of the Company and are senior in right of payment to all existing and future subordinated indebtedness of the Company. The Company is a holding company that conducts all of its operations through subsidiaries; consequently, the senior notes are structurally subordinated to all obligations of its subsidiaries. Interest on the Company's senior notes is payable semiannually.

Principal payments scheduled to be made on the Company's long-term debt are as follows (in millions):

2020	$	450
2021	$	500
2022	$	600
2023	$	—
2024	$	—
Thereafter	$	750

Interest expense activity is as follows:

	Year Ended December 31,		
	2019	2018	2017
		(in millions)	
Cash payments for interest	$ 117	$ 133	$ 164
Accretion of finance lease	4	—	—
Amortization of issuance discounts	1	1	1
Amortization of capitalized loan fees	4	4	4
Net changes in accruals	—	(6)	(9)
Interest incurred	126	132	160
Less capitalized interest	(5)	(6)	(7)
Total interest expense	$ 121	$ 126	$ 153

NOTE 8. Incentive Plans

Deferred compensation retirement plan. The Company's deferred compensation retirement plan allows for qualified officers and certain key employees of the Company to contribute up to 50 percent of their base salary, an increase from 25 percent prior to 2019, and 100 percent of their annual bonus. The Company provides a matching contribution of 100 percent of the officer's and key employee's contribution limited up to the first ten percent of the officer's base salary and eight percent of the key employee's base salary. The Company's matching contribution vests immediately. A trust fund has been established by the Company to accumulate the contributions made under this retirement plan.

The Company match for the deferred compensation plan is as follows:

	Year Ended December 31,		
	2019	2018	2017
		(in millions)	
Deferred compensation plan	$ 2	$ 3	$ 3

401(k) plan. The Pioneer Natural Resources USA, Inc. ("Pioneer USA," a wholly-owned subsidiary of the Company) 401(k) and Matching Plan (the "401(k) Plan") is a defined contribution plan established under the Internal Revenue Code Section 401. All regular full-time and part-time employees of Pioneer USA are eligible to participate in the 401(k) Plan on the first day of the month following their date of hire. Participants may contribute up to 80 percent of their annual base salary into the 401(k) Plan. Matching contributions are made to the 401(k) Plan in cash by Pioneer USA in amounts equal to 200 percent of a participant's contributions to the 401(k) Plan that are not in excess of five percent of the participant's annual base salary (the "Matching Contribution"). Each participant's account is credited with the participant's contributions, Matching Contributions and allocations of the 401(k) Plan's earnings. Participants are fully vested in their account balances except for Matching Contributions and their proportionate share of 401(k) Plan earnings attributable to Matching Contributions, which proportionately vest over a four-year period that begins on the participant's date of hire. Beginning in February 2018, eligible employees are automatically enrolled in the 401(k) Plan at a contribution rate of five percent of the employee's annual base salary, unless the employee opts out of participation or makes an alternate election within 30 days of becoming eligible for participation.

The Company match for the 401(k) plan is as follows:

	Year Ended December 31,		
	2019	2018	2017
		(in millions)	
401(k) plan	$ 27	$ 36	$ 25

Long-Term Incentive Plan. The Company's Amended and Restated 2006 Long-Term Incentive Plan ("LTIP") provides for the granting of various forms of awards, including stock options, stock appreciation rights, performance units, restricted stock and restricted stock units to directors, officers and employees of the Company.

The number of shares available for grant pursuant to awards under the LTIP is as follows:

	As of December 31, 2019
Approved and authorized awards	12,600,000
Awards granted under plan	(8,371,882)
Awards available for future grant	4,228,118

Employee Stock Purchase Plan. The Company's Employee Stock Purchase Plan ("ESPP") allows eligible employees to annually purchase the Company's common stock at a discounted price. Officers of the Company are not eligible to participate in the ESPP. Contributions to the ESPP are limited to 15 percent of an employee's base salary (subject to certain ESPP limits) during the eight-month offering period (January 1 to August 31). Participants in the ESPP purchase the Company's common stock at a price that is 15 percent below the closing sales price of the Company's common stock on either the first day or the last day of each offering period, whichever closing sales price is lower.

The number of shares available for issuance under the ESPP is as follows:

	As of December 31, 2019
Approved and authorized shares	1,250,000
Shares issued	(1,056,938)
Shares available for future issuance	193,062

Stock-based compensation expense and the associated income tax benefit for awards issued under both the LTIP and ESPP are as follows:

	Year Ended December 31,		
	2019	2018	2017
		(in millions)	
Restricted stock - Equity Awards	$ 79	$ 65	$ 60
Restricted stock - Liability Awards	19	17	24
Performance unit awards	19	18	17
Employee stock purchase plan	2	2	2
Total stock-based compensation expense	$ 119	$ 102	$ 103
Income tax benefit	$ 18	$ 17	$ 19

As of December 31, 2019, there was $95 million of unrecorded stock-based compensation expense related to unvested share-based compensation plans, including $25 million attributable to Liability Awards that are expected to be settled in cash on their vesting dates. The weighted average remaining vesting period of the awards is less than three years.

Restricted stock awards. During 2019, the Company awarded 934,735 restricted shares or units of the Company's common stock as compensation to directors, officers and employees of the Company, including 221,497 shares or units representing Liability Awards.

Restricted stock award activity is as follows:

	Year Ended December 31, 2019		
	Equity Awards		Liability Awards
	Number of Shares	Weighted Average Grant-Date Fair Value	Number of shares
Beginning incentive compensation awards	799,672	$ 165.10	201,501
Awards granted	713,238	$ 137.23	221,497
Awards forfeited	(49,873)	$ 147.06	(32,316)
Awards vested	(638,844)	$ 154.89	(143,831)
Ending incentive compensation awards	824,193	$ 149.99	246,851

The weighted average grant-date fair value per unit of restricted stock Equity Awards awarded during 2019, 2018 and 2017 was $137.23, $180.66 and $180.50, respectively. The grant-date fair value of restricted stock Equity Awards that vested during 2019, 2018 and 2017 was $99 million, $67 million and $70 million, respectively.

As of December 31, 2019 and 2018, accounts payable - due to affiliates in the consolidated balance sheets includes $11 million and $14 million, respectively, of liabilities attributable to the Liability Awards, representing the fair value of the earned, but unvested, portion of the outstanding awards as of that date.

Cash paid for vested Liability Awards is as follows:

	Year Ended December 31,		
	2019	2018	2017
		(in millions)	
Cash paid for vested Liability Awards	$ 20	$ 24	$ 20

Performance unit awards. Each year, at its discretion, the Company awards performance units to certain of the Company's officers under the LTIP. The number of shares of common stock to be issued is determined by comparing the Company's total shareholder return to the total shareholder return of a predetermined group of peer companies over the performance period. The performance unit awards vest over a 34-month service period.

The grant-date fair value per unit of the 2019, 2018 and 2017 performance unit awards were $165.84, $246.18 and $258.27, respectively and are being recorded as stock-based compensation expense ratably over the performance period. The fair value of the performance unit awards was determined using the Monte Carlo simulation model that utilizes multiple input variables to determine the probability of satisfying the market condition stipulated in the award grant and calculates the fair value of the award. Expected volatilities utilized in the model were estimated using a historical period consistent with the performance period of approximately three years. The risk-free interest rate was based on the United States Treasury rate for a term commensurate with the expected life of the grant.

Assumptions used to estimate the fair value of performance unit awards granted in each of the following years are as follows:

	2019	2018	2017
Risk-free interest rate	2.49%	2.41%	1.42%
Range of volatilities	27.7% - 43.4%	30.4% - 53.3%	33.6% - 58.2%

Performance unit activity is as follows:

	Year Ended December 31, 2019	
	Number of Units (a)	Weighted Average Grant-Date Fair Value
Beginning performance unit awards	119,169	$ 251.92
Units granted	86,483	$ 165.84
Units vested (b)	(89,437)	$ 247.10
Ending performance unit awards	116,215	$ 191.58

(a) Amount reflects the number of performance units initially granted. The actual payout of shares upon vesting may be between zero and 250 percent of the performance units included in this table depending upon the total shareholder return ranking of the Company compared to peer companies at the vesting date.
(b) Amount reflects the number of performance units vested upon retirement of eligible officers and the vesting of performance units for which the service period has ended. On December 31, 2019, the service period lapsed on 58,539 performance unit awards that earned 1.00 shares for each vested award. The 58,539 aggregate shares of common stock were issued on January 2, 2020. Of the 58,539 shares of common stock issued, 1,911 shares were associated with units that vested in prior years associated with the retirement of an eligible officer. In addition, 32,809 units vested upon retirement of eligible officers and will be issued when the performance period ends in 2020 and 2021.

The grant-date fair value of vested performance units is as follows:

	Year Ended December 31,		
	2019	2018	2017
		(in millions)	
Grant-date fair value of vested performance units	$ 22	$ 21	$ 18

NOTE 9. Asset Retirement Obligations

The Company's asset retirement obligations primarily relate to the future plugging and abandonment of wells and related facilities. Market risk premiums associated with asset retirement obligations are estimated to represent a component of the Company's credit-adjusted risk-free rate that is utilized in the calculations of asset retirement obligations.

Asset retirement obligations activity is as follows:

	Year Ended December 31,	
	2019	2018
	(in millions)	
Beginning asset retirement obligations	$ 183	$ 271
New wells placed on production	5	1
Changes in estimates (a)	82	16
Dispositions	(37)	(89)
Liabilities settled	(52)	(30)
Accretion of discount	10	14
Ending asset retirement obligations	191	183
Less current portion of asset retirement obligations	73	25
Asset retirement obligations, long term	$ 118	$ 158

(a) Changes in estimates are determined based on several factors, including abandonment cost estimates based on recent actual costs incurred to abandon wells, credit-adjusted risk-free discount rates and well life estimates. The 2019 change in estimate is primarily due to accelerating the forecasted timing of abandoning certain of the Company's vertical oil and gas wells, which had the effect of increasing the present value and current portion of the abandonment obligation attributable to those wells.

NOTE 10. Leases

As of December 31, 2018, the Company was the deemed owner (for accounting purposes) of the Company's new corporate headquarters (the "Hidden Ridge Building") during the construction period and accounted for this deemed ownership following the build-to-suit accounting guidance under ASC 840. On January 1, 2019, upon implementation of ASC 842, the Company was no longer considered the deemed owner of the Hidden Ridge Building and the Company derecognized the build-to-suit asset of $217 million and liability of $219 million.

The Company had a variable interest in the entity responsible for constructing the Hidden Ridge Building. The Company was not the primary beneficiary of the variable interest entity and only had a profit sharing interest after certain economic returns were achieved. The Company had no exposure to the variable interest entity's losses or future liabilities, if any. In December 2019, the Company sold its interest in the variable interest entity for net cash proceeds of $56 million and recognized a net gain on the sale of the building of $56 million, which is recorded in interest and other in the consolidated statement of operations. The Company has no continuing involvement in entity subsequent to the sale. See Note 15 for additional information.

The Company recognized a finance lease upon commencement of the Hidden Ridge Building lease in October 2019, the balances of which are as follows:

	Consolidated Balance Sheet Location	As of December 31, 2019	
		(in millions)	
Finance lease right-of-use asset	Other property and equipment, net	$	556
Finance lease liability	Other liabilities - current	$	16
Finance lease liability	Other liabilities - noncurrent	$	556

In November 2019, the Company recorded accelerated amortization of $28 million in other expense in the consolidated statements of operations to fully amortize the remaining operating lease right-of-use asset associated with its former corporate headquarters. As of December 31, 2019, the consolidated balance sheet includes $27 million of operating lease liabilities related to its former corporate headquarters. See Note 16 for additional information.

The components of lease costs, including amounts recoverable from joint operating partners, are as follows:

	Year Ended December 31, 2019	
	(in millions)	
Finance lease cost:		
Amortization of right-of-use asset (a)	$	7
Interest on lease liability		4
Operating lease cost (b)		200
Short-term lease cost (c)		33
Variable lease cost (d)		73
Total lease cost	$	317

(a) Represents straight-line rent cost associated with the Company's finance lease right-of-use asset.
(b) Represents straight-line rent cost associated with the Company's operating lease right-of-use assets.
(c) Represents costs associated with short-term leases (those with a contractual term of 12 months or less) that are not included in the consolidated balance sheets.
(d) Variable lease costs are primarily comprised of the non-lease service component of drilling rig commitments above the minimum required payments. Both the minimum required payments and the non-lease service component of the drilling rig commitments are capitalized as additions to oil and gas properties.

For the year ended December 31, 2019, cash paid of $103 million for operating, short-term and variable leases and $4 million for finance leases is included in net cash provided by operating activities and $1 million of finance lease principal payments is included in net cash used in financing activities in the consolidated statements of cash flows. For the same period, the Company also incurred operating and variable lease costs associated with drilling operations of $180 million, which is capitalized as additions to oil and gas properties and is included in investing cash flows in the consolidated statements of cash flows.

The changes in lease liabilities are as follows:

	Year Ended December 31, 2019			
	Operating		Finance	
	(in millions)			
Beginning lease liabilities (a)	$	325	$	—
Liabilities assumed in exchange for new right-of-use assets (b)		142		573
Contract modifications (c)		4		—
Dispositions		(1)		—
Liabilities settled		(177)		(5)
Accretion of discount (d)		13		4
Ending lease liabilities (e)	$	306	$	572

(a) Represents January 1, 2019 balance upon adoption of ASC 842.
(b) Represents noncash leasing activity. The weighted-average discount rate used in 2019 to determine the present value of future operating and finance lease payments is 3.3 percent and 3.0 percent, respectively.
(c) Represents changes in lease liabilities due to modifications of original contract terms.
(d) Represents imputed interest on discounted future cash payments.
(e) As of December 31, 2019, the weighted-average remaining lease term of the Company's operating and finance leases is three and 20 years, respectively.

Maturities of lease obligations are as follows:

	As of December 31, 2019	
	Operating	Finance
	(in millions)	
2020	$ 149	$ 33
2021	92	33
2022	47	34
2023	13	35
2024	8	35
Thereafter	18	603
Total lease payments	327	773
Less present value discount	(21)	(201)
Present value of lease liabilities	$ 306	$ 572

At December 31, 2019, the Company has commitments for additional operating leases of approximately $38 million expected to commence in 2020 with lease terms of 4 years.

NOTE 11. Commitments and Contingencies

Severance agreements. The Company has entered into severance and change in control agreements with its officers and certain key employees. The current annual salaries for the officers and key employees covered under such agreements total $15 million.

Indemnifications. The Company has agreed to indemnify its directors and certain of its officers, employees and agents with respect to claims and damages arising from acts or omissions taken in such capacity, as well as with respect to certain litigation.

Legal actions. The Company is party to various proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to these proceedings and claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. The Company records reserves for contingencies when information available indicates that a loss is probable and the amount of the loss can be reasonably estimated.

Environmental. Environmental expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Environmental expenditures that extend the life of the related property or mitigate or prevent future environmental contamination are capitalized. Liabilities for expenditures that will not qualify for capitalization are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are undiscounted unless the timing of cash payments for the liability is fixed or reliably determinable. Environmental liabilities normally involve estimates that are subject to revision until settlement or remediation occurs.

Obligations following divestitures. In connection with its divestiture transactions, the Company may retain certain liabilities and provide the purchaser certain indemnifications, subject to defined limitations, which may apply to identified preclosing matters, including matters of litigation, environmental contingencies, royalty and income taxes. Also associated with its divestiture transactions, the Company has issued and received guarantees to facilitate the transfer of contractual obligations, such as firm transportation agreements or gathering and processing arrangements. The Company does not recognize a liability if the fair value of the obligation is immaterial or the likelihood of making payments under these guarantees is remote.

South Texas Divestiture. In conjunction with the South Texas Divestiture, the Company transferred its long-term midstream agreements and associated MVC's to the buyer. However, the Company retained the obligation to pay 100 percent of any deficiency fees associated with the MVC's from January 2019 through July 2022. The buyer is required to reimburse the Company for 18 percent of the deficiency fees paid by the Company from January 2019 through July 2022; such reimbursement will be paid by the buyer in installments beginning in 2023 through 2025. Assuming 100 percent of the MVC's are paid as deficiency fees, the maximum amount of future payments for this obligation would be approximately $620 million as of December 31, 2019. The Company's estimated deficiency fee obligation as of December 31, 2019 is $394 million, of which $153 million is included in other current liabilities in the consolidated balance sheets. The corresponding estimated deficiency fee receivable from the buyer of $69 million is included in noncurrent other assets in the consolidated balance sheets. The Company has received credit support for the deficiency fee receivable and contingent consideration of up to $325 million.

Raton transportation commitments. In July 2018, the Company completed the sale of its gas field assets in the Raton Basin to an unaffiliated third party and transferred certain gas transportation commitments, which extend through 2032, to the buyer for which the Company has provided a guarantee. Assuming 100 percent of the remaining commitments are paid by the Company under its guarantee, the maximum amount of future payments would be approximately $90 million as of December 31, 2019. The Company has received credit support for the commitments of up to $50 million. During 2019, the Company paid $12 million in gas transportation fees associated with the transferred commitment and was fully reimbursed.

West Eagle Ford Shale commitments. In April 2018, the Company completed the sale of its West Eagle Ford Shale gas and liquids field to an unaffiliated third party and transferred certain gas and liquids transportation commitments, which extend through 2022, to the buyer for which the Company has provided a guarantee. Assuming 100 percent of the remaining commitments are paid by the Company under its guarantee, the maximum amount of future payments would be approximately $20 million as of December 31, 2019. The Company has received credit support for the commitments of up to $19 million.

Certain contractual obligations were retained by the Company after the South Texas Divestiture, the divestiture of the Company's gas field assets in the Raton Basin, the divestiture of the Company's pressure pumping assets and the decommissioning of the Company's sand mine operations in Brady, Texas. These contracts were primarily related to firm transportation and storage agreements in which the Company is unlikely to realize any benefit. The estimated obligations are included in other current or noncurrent liabilities in the consolidated balance sheets.

The changes in contract obligations are as follows:

	Year Ended December 31, 2019
	(in millions)
Beginning contract obligations	$111
Additions (a)	400
Liabilities settled	(51)
Accretion of discount	10
Changes in estimate (b)	(2)
Ending contract obligations	$ 468

(a) Additions include a $348 million deficiency fee obligation related to the South Texas Divestiture, $49 million of South Texas accrued deficiency fees from January 2019 through April 2019, $2 million of sand storage deficiencies associated with the sale of pressure pumping assets and $1 million related to sand mine decommissioning.
(b) Represents the difference between estimated and actual liabilities settled.

Texas Commission on Environmental Quality ("TCEQ") enforcement action. The TCEQ pursued an enforcement action against the Company, including monetary sanctions, due to various alleged air emissions occurring during the Company's ownership in 2016 and 2017 of the Fain gas plant in the West Panhandle region of Texas, which was sold during 2018. Effective as of October 25, 2019, the Company and the TCEQ entered into an agreed order that provides for the Company making a final penalty payment of $188,400. By letter dated November 1, 2019, the Company was informed by the TCEQ that it had fulfilled the requirements of the order.

Firm commitments. The Company from time to time enters into, and is a party to, take-or-pay agreements, which include contractual commitments to purchase sand and water for use in the Company's drilling operations and contractual commitments with midstream service companies and pipeline carriers for future gathering, processing, transportation, fractionation and storage. These commitments are normal and customary for the Company's business activities. Certain future minimum gathering, processing, transportation, fractionation and storage fees are based upon rates and tariffs that are subject to change over the terms of the commitments.

Minimum firm commitments are as follows:

	As of December 31, 2019	
	Firm Commitments	
	(in millions)	
2020	$	532
2021		534
2022		471
2023		407
2024		412
Thereafter		1,784
Total minimum firm commitments	$	4,140

Gas delivery commitments. The Company has contracts that require delivery of fixed volumes of gas. The Company intends to fulfill its short-term and long-term obligations with production or from purchases of third party volumes.

Delivery commitments for gas are as follows:

	As of December 31, 2019
	(MMBtu per day)
2020	196,557
2021	175,000
2022	175,000
2023	175,000
2024	150,137
Thereafter	156,164
Total gas delivery commitments	1,027,858

NOTE 12. Related Party Transactions

In December 2018, the Company completed the sale of its pressure pumping assets to ProPetro in exchange for 16.6 million shares of ProPetro common stock and $110 million of cash that was received during the first quarter of 2019. ProPetro is considered a related party as the shares received represent 16 percent of ProPetro's outstanding common stock. In addition to the sale of equipment and related facilities, the Company entered into a long-term agreement with ProPetro for it to provide pressure pumping and related services. The costs of these services are capitalized in oil and gas properties as incurred. See Note 3 for additional information.

In October 2019, Phillip A. Gobe, a nonemployee member of the Company's board of directors, was appointed by the board of directors of ProPetro to serve as its Executive Chairman. Mark S. Berg, the Company's Executive Vice President Corporate/Vertically Integrated Operations, continues to serve as a member of the ProPetro board of directors under the Company's right to designate a director to the board of directors of ProPetro so long as the Company owns five percent or more of ProPetro's outstanding common stock.

Transactions and balances with ProPetro are as follows:

	Year Ended December 31,	
	2019	2018
	(in millions)	
Pressure pumping related services charges (a)	$ 461	$ 111

(a) Represents pressure pumping and related services provided by ProPetro as part of a long-term agreement. The 2018 amount represents charges associated with the pressure pumping and related services performed by ProPetro in the normal course of business prior to the Company's sale of its pressure pumping assets to ProPetro.

	As of December 31,	
	2019	2018
	(in millions)	
Accounts receivable - due from affiliate (a)	$ 3	$ 119
Accounts payable - due to affiliate (b)	$ 88	$ 37

(a) Represents employee-related charges to be reimbursed by ProPetro. The balance as of December 31, 2018 also includes $110 million of cash consideration received during the first quarter of 2019.

(b) Represents pressure pumping and related services provided by ProPetro as part of a long-term agreement. The balance as of December 31, 2018 represents invoices associated with the pressure pumping and related services performed by ProPetro in the normal course of business prior to the Company's sale of its pressure pumping assets to ProPetro.

NOTE 13. Major Customers

Purchasers of the Company's oil, NGL and gas production that individually accounted for ten percent or more of the Company's oil and gas revenues in at least one of the three years ended December 31, 2019 are as follows:

	Year Ended December 31,		
	2019	2018	2017
Sunoco Logistics Partners L.P.	33%	28%	21%
Occidental Energy Marketing Inc.	20%	17%	16%
Plains Marketing L.P.	13%	15%	14%
Enterprise Products Partners L.P.	1%	6%	11%

The loss of any of these major purchasers of oil, NGL and gas production could have a material adverse effect on the ability of the Company to produce and sell its oil, NGL and gas production.

Purchasers of the Company's purchased oil and gas that individually accounted for ten percent or more of the Company's sales of purchased oil and gas in at least one of the three years ended December 31, 2019 are as follows:

	Year Ended December 31,		
	2019	2018	2017
Occidental Energy Marketing Inc.	30%	34%	39%
BP Energy	5%	9%	11%
Exxon Mobil	4%	5%	11%
Valero Marketing and Supply Company	2%	9%	14%

The loss of any of these major purchasers of purchased oil and gas would not be expected to have an adverse effect on the ability of the Company to sell commodities it purchases from third parties.

NOTE 14. Revenue Recognition

Disaggregated revenue from contracts with purchasers. Revenues on sales of oil, NGL, gas and purchased oil and gas are recognized when control of the product is transferred to the purchaser and payment can be reasonably assured. Sales prices for oil, NGL and gas production are negotiated based on factors normally considered in the industry, such as an index or spot price, distance from the well to the pipeline or market, commodity quality and prevailing supply and demand conditions. As such, the prices of oil, NGL and gas generally fluctuate based on the relevant market index rates.

Disaggregated revenue from contracts with purchasers by product type is as follows:

	Year Ended December 31,	
	2019	2018
	(in millions)	
Oil sales	$ 4,168	$ 3,991
NGL sales	510	695
Gas sales	238	305
Total oil and gas sales	4,916	4,991
Sales of purchased oil	4,726	4,339
Sales of purchased gas	29	49
Total sales of purchased oil and gas	4,755	4,388
Total revenue from contracts with purchasers	$ 9,671	$ 9,379

Performance obligations and contract balances. The majority of the Company's product sale commitments are short-term in nature with a contract term of one year or less. The Company typically satisfies its performance obligations upon transfer of control as described above in *Disaggregated revenue from contracts with purchasers* and records the related revenue in the month production is delivered to the purchaser. Settlement statements for sales of oil, NGL and gas and sales of purchased oil and gas may not be received for 30 to 60 days after the date the volumes are delivered, and as a result, the Company is required to estimate the amount of volumes 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 in the month that payment is received from the purchaser. As of December 31, 2019 and 2018, the accounts receivable balance representing amounts due or billable under the terms of contracts with purchasers was $968 million and $646 million, respectively.

NOTE 15. Interest and Other Income

The components of interest and other income are as follows:

	Year Ended December 31,		
	2019	2018	2017
		(in millions)	
Gain on sale of variable interest (Note 10)	$ 56	$ —	$ —
Interest income	17	29	32
Deferred compensation plan income (loss)	15	(2)	4
Investment in affiliate valuation adjustment (Note 4)	15	—	—
Severance and sales tax refunds	6	1	13
Seismic data sales	5	5	—
Contingent consideration valuation adjustment (Note 4)	(45)	—	—
Other	7	5	4
Total interest and other income	$ 76	$ 38	$ 53

NOTE 16. Other Expense

The components of other expense are as follows:

	Year Ended December 31,		
	2019	2018	2017
		(in millions)	
Restructuring charges (a)	$ 159	$ —	$ —
Transportation commitment charges (b)	74	161	167
Corporate headquarters move-related costs (c)	41	—	—
Asset impairment (d)	38	11	2
Asset divestiture-related charges (e)	25	170	—
Idle drilling and well service equipment charges (f)	25	—	—
Sand mine decommissioning-related charges (g)	23	443	—
Legal and environmental charges	19	21	20
Vertical integration services loss (h)	15	2	17
Other	29	41	38
Total other expense	$ 448	$ 849	$ 244

(a) Represents employee-related charges associated with the Corporate Restructuring Program. See Note 3 and Note 8 for additional information.
(b) Primarily represents firm transportation charges on excess pipeline capacity commitments.
(c) Represents costs associated with relocating to the Hidden Ridge Building, including $28 million of accelerated amortization of the operating lease right-of-use asset associated with the Company's former corporate headquarters and $13 million of exit and move-related costs.
(d) Primarily represents inventory and other asset impairment charges associated with the decommissioning of the Company's Brady, Texas sand mine and the divestiture of the Company's pumping services assets. See Note 3 and Note 4 for additional information.
(e) Primarily represents employee-related charges and contract termination charges associated with the Company's divestitures. See Note 3 for additional information.
(f) Primarily represents expenses attributable to idle frac fleet and drilling rig fees that are not chargeable to joint operations.
(g) Represents accelerated depreciation related to the decommission of the Company's Brady, Texas sand mine. See Note 3 for additional information.
(h) Primarily represents net margins (attributable to third party working interest owners) that result from Company-provided vertically integrated services, which are ancillary to and supportive of the Company's oil and gas joint operating activities, and do not represent intercompany transactions. For the three years ended December 31, 2019, 2018 and 2017, these vertical integration net margins included $51 million, $128 million and $140 million of gross vertical integration revenues, respectively, and $66 million, $130 million and $157 million of total vertical integration costs and expenses, respectively.

NOTE 17. Income Taxes

The Company and its eligible subsidiaries file a consolidated U.S. federal income tax return. Certain subsidiaries are not eligible to be included in the consolidated U.S. federal income tax return and separate provisions for income taxes have been determined for these entities or groups of entities. The tax returns and the amount of taxable income or loss are subject to examination by U.S. federal, state, local and foreign taxing authorities.

The Company continually assesses both positive and negative evidence to determine whether it is more likely than not that deferred tax assets can be realized prior to their expiration. Pioneer monitors Company-specific, oil and gas industry and worldwide economic factors and based on that information, along with other data, reassesses the likelihood that the Company's net operating loss carryforwards ("NOLs") and other deferred tax attributes in the U.S. federal, state, local and foreign tax jurisdictions will be utilized prior to their expiration.

Enactment of the Tax Cuts and Jobs Act. On December 22, 2017, the U.S. enacted the Tax Cuts and Jobs Act (the "Tax Reform Legislation"), which introduced significant changes to the U.S. federal income tax law. The changes that most impact the Company include:

- A reduction in the federal corporate income tax rate from 35 percent to 21 percent. The rate reduction is effective for the Company as of January 1, 2018. The application of the rate change on the Company's deferred tax liabilities resulted in a $625 million income tax benefit to the Company during 2017.
- Repeal of the corporate alternative minimum tax ("AMT"). The Tax Reform Legislation provides that existing AMT credit carryovers are refundable beginning in 2018. As of December 31, 2019, the Company had AMT credit carryovers of $12 million that are expected to be fully refunded by 2022.
- The Tax Reform Legislation preserves the deductibility of intangible drilling costs and provides for 100 percent bonus depreciation on personal tangible property expenditures through 2022. The bonus depreciation percentage will be phased out from 2023 through 2026.

The Tax Reform Legislation is a comprehensive bill containing other provisions, such as limitations on the deductibility of interest expense and certain executive compensation, that are not expected to materially affect Pioneer. The ultimate impact of the Tax Reform Legislation may differ from the Company's estimates due to changes in the interpretations and assumptions made by the Company as well as additional regulatory guidance that may be issued.

Uncertain tax positions. The Company has unrecognized tax benefits ("UTBs") resulting from research and experimental expenditures related to horizontal drilling and completion innovations. In December 2019, the Company and the taxing authorities effectively settled the uncertain tax position for the 2012-2015 tax years. The Company believes it will substantially resolve the uncertainties associated with the remaining UTB within the next twelve months.

Unrecognized tax benefit activity is as follows:

	Year Ended December 31,		
	2019	2018	2017
		(in millions)	
Beginning unrecognized tax benefits	$ 141	$ 124	$ 112
Current year additions	—	17	12
Effectively settled tax positions	(102)	—	—
Ending unrecognized tax benefits	$ 39	$ 141	$ 124

Other tax matters.

Net tax refunds are as follows:

	Year Ended December 31,		
	2019	2018	2017
		(in millions)	
Tax refunds, net	$ (5)	$ —	$ —

The Company files income tax returns in the U.S. federal jurisdiction and various state and foreign jurisdictions. As of December 31, 2019, there are no proposed adjustments in any jurisdiction that would have a significant effect on the Company's future results of operations or financial position.

The earliest open years in the Company's key jurisdictions are as follows:

U.S. federal	2012
Various U.S. states	2013

Income tax (provision) benefit is as follows:

	Year Ended December 31,		
	2019	2018	2017
		(in millions)	
Current:			
U.S. federal	$ 8	$ —	$ 5
U.S. state	(3)	(2)	—
Current income tax (provision) benefit	5	(2)	5
Deferred:			
U.S. federal	(224)	(258)	526
U.S. state	(12)	(16)	(7)
Deferred income tax (provision) benefit	(236)	(274)	519
Income tax (provision) benefit	$ (231)	$ (276)	$ 524

The effective tax rate for income (loss) is reconciled to the United States federal statutory rate as follows:

	Year Ended December 31,		
	2019	2018	2017
		(in millions, except percentages)	
Income before income taxes	$ 987	$ 1,251	$ 309
Net loss attributable to noncontrolling interests	—	3	—
Income attributable to common stockholders before income taxes	$ 987	$ 1,254	$ 309
Federal statutory income tax rate	21%	21%	35%
Provision for federal income taxes at the statutory rate	(207)	(263)	(108)
State income tax provision (net of federal tax)	(12)	(12)	(4)
Change in federal income tax rate (a)	—	—	625
Other	(12)	(1)	11
Income tax (provision) benefit	$ (231)	$ (276)	$ 524
Effective income tax rate, excluding net loss attributable to noncontrolling interests	23%	22%	(170%)

(a) During 2017, the Company recorded a benefit of $625 million as a result of the Tax Reform Legislation that reduced the federal income tax rate beginning in 2018.

Significant components of deferred tax assets and deferred tax liabilities are as follows:

	As of December 31,	
	2019	2018
	(in millions)	
Deferred tax assets:		
Net operating loss carryforward (a)	$ 996	$ 882
Credit carryforwards (b)	101	111
Deferred interest carryforward (c)	43	—
Asset retirement obligations	41	40
Incentive plans	40	48
Net deferred hedge losses	—	11
South Texas Divestiture	75	—
Lease deferred tax assets	191	—
Other	47	51
Deferred tax assets	1,534	1,143
Deferred tax liabilities:		
Oil and gas properties, principally due to differences in basis, depletion and the deduction of intangible drilling costs for tax purposes	(2,628)	(2,248)
Other property and equipment, principally due to the deduction of bonus depreciation for tax purposes and differences in lease right of use assets	(189)	(47)
Net deferred hedge gains	(4)	—
South Texas Divestiture	(35)	—
Lease deferred tax liabilities	(61)	—
Other	(6)	—
Deferred tax liabilities	(2,923)	(2,295)
Net deferred tax liability	$ (1,389)	$ (1,152)

(a) Net operating loss carryforwards as of December 31, 2019, consist of $5.0 billion of U.S. federal NOLs, which expire between 2032 and 2039 and $177 million of Colorado NOLs that begin to expire in 2027. The Colorado NOL has a fully offsetting valuation allowance.

(b) Credit carryforwards as of December 31, 2019, consist of $12 million of U.S. federal minimum tax credits and U.S. federal and Texas credits for research activities of $88 million and $1 million, respectively. The U.S. federal and state research credits as of December 31, 2019 exclude $39 million of unrecognized tax benefits.

(c) The deferred interest carryforward represents disallowed interest deductions under IRC Section 163(j) (Limitation on Deduction for Interest on Certain Indebtedness) for the current and prior years. The disallowed interest can be carried forward indefinitely and utilized in future years.

NOTE 18. Net Income Per Share

The Company's basic net income per share attributable to common stockholders is computed as (i) net income attributable to common stockholders, (ii) less participating share- and unit-based basic earnings (iii) divided by weighted average basic shares outstanding. The Company's diluted net income per share attributable to common stockholders is computed as (i) basic net income attributable to common stockholders, (ii) plus diluted adjustments to participating undistributed earnings (iii) divided by weighted average diluted shares outstanding. Diluted net income per share attributable to common stockholders is calculated under both the two-class method and the treasury stock method and the more dilutive of the two calculations is presented.

The components of basic and diluted net income per share attributable to common stockholders are as follows:

	Year Ended December 31,		
	2019	2018	2017
		(in millions)	
Net income attributable to common stockholders	$ 756	$ 978	$ 833
Participating share based earnings (a)	(3)	(5)	(6)
Basic and diluted net income attributable to common stockholders	$ 753	$ 973	$ 827
Basic and diluted weighted average shares outstanding	167	171	170

(a) Unvested restricted stock awards represent participating securities because they participate in nonforfeitable dividends with the common equity owners of the Company. Participating share- or unit-based earnings represent the distributed and undistributed earnings of the Company attributable to the participating securities. Unvested restricted stock awards do not participate in undistributed net losses as they are not contractually obligated to do so.

Stock repurchase program. In December 2018, the Company's board of directors authorized a common stock repurchase program that allows the Company to repurchase up to $2 billion of its common stock. Under this stock repurchase program, the Company may repurchase shares from time to time at management's discretion in accordance with applicable securities laws. In addition, the Company may repurchase shares pursuant to a trading plan meeting the requirements of Rule 10b5-1 under the Securities Act of 1934, which would permit the Company to repurchase shares at times that may otherwise be prohibited under the Company's insider trading policy. The stock repurchase program has no time limit, may be modified, suspended or terminated at any time by the board of directors.

Shares repurchased are as follows:

	Year Ended December 31,		
	2019	2018 (a)	2017
		(in millions)	
Shares repurchased	$ 622	$ 149	$ —

(a) During 2018, the Company repurchased $22 million of common stock pursuant to a previously authorized common stock repurchase program and $127 million of common stock pursuant to the current authorized common stock repurchase program.

As of December 31, 2019, $1.3 billion remains available for use to repurchase shares under the Company's common stock repurchase program.

NOTE 19. Subsequent Events

Dividends. On February 19, 2020, the board of directors declared a quarterly cash dividend of $0.55 per share on the Company's outstanding common stock, payable April 14, 2020 to stockholders of record at the close of business on March 31, 2020.

Senior Notes. The Company's outstanding 7.50% Senior Notes matured on January 15, 2020. The Company funded the payment of the $450 million principal balance with cash on hand. See Note 7 for additional information.

Oil & Gas Exploration and Production Activities

The Company has only one reportable operating segment, which is oil and gas development, exploration and production in the U.S. See the Company's accompanying consolidated statements of operations for information about results of operations for oil and gas producing activities.

Capitalized Costs

	December 31,	
	2019	2018
	(in millions)	
Oil and gas properties:		
Proved	$ 22,444	$ 21,165
Unproved	584	601
Capitalized costs for oil and gas properties	23,028	21,766
Less accumulated depletion, depreciation and amortization	(8,583)	(8,218)
Net capitalized costs for oil and gas properties	$ 14,445	$ 13,548

Costs Incurred for Oil and Gas Producing Activities

	Year Ended December 31,		
	2019	2018	2017
		(in millions)	
Property acquisition costs:			
Proved	$ 2	$ 1	$ 8
Unproved	26	64	128
Exploration costs	2,199	2,654	2,033
Development costs	743	949	628
Total costs incurred (a)	$ 2,970	$ 3,668	$ 2,797

(a) The costs incurred for oil and gas producing activities include amounts related to asset retirement obligations as follows:

	Year Ended December 31,		
	2019	2018	2017
		(in millions)	
Exploration costs	$ 10	$ 1	$ 2
Development costs	75	16	(19)
	$ 85	$ 17	$ (17)

Reserve Quantity Information

The estimates of the Company's proved reserves as of December 31, 2019, 2018 and 2017 were based on evaluations prepared by the Company's engineers and audited by independent petroleum engineers with respect to the Company's major properties and prepared by the Company's engineers with respect to all other properties. Proved reserves were estimated in accordance with guidelines established by the U.S. Securities and Exchange Commission (the "SEC") and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions based upon an average of the first-day-of-the-month commodity price during the 12-month period ending on the balance sheet date with no provision for price and cost escalations except by contractual arrangements.

Proved reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in commodity prices and operating costs. The Company emphasizes that proved reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The following table provides a rollforward of total proved reserves. Oil and NGL volumes are expressed in thousands of Bbls ("MBbls"), gas volumes are expressed in millions of cubic feet ("MMcf") and total volumes are expressed in thousands of barrels of oil equivalent ("MBOE").

	Year Ended December 31,											
	2019				2018				2017			
	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf) (a)	Total (MBOE)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf) (a)	Total (MBOE)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf) (a)	Total (MBOE)
Balance, January 1	565,010	240,914	1,458,574	1,049,020	482,889	210,497	1,751,880	985,366	378,196	136,941	1,264,729	725,925
Production (b)	(77,509)	(26,398)	(145,026)	(128,078)	(69,583)	(23,280)	(157,278)	(119,076)	(57,878)	(20,078)	(143,464)	(101,867)
Revisions of previous estimates	(30,216)	29,415	94,767	14,994	(15,665)	21,087	257,502	48,339	20,140	44,995	365,275	126,015
Extensions and discoveries	167,022	60,069	293,507	276,009	175,067	51,414	230,272	264,859	146,822	49,378	266,347	240,591
Sales of minerals-in-place	(20,603)	(22,032)	(202,401)	(76,369)	(7,722)	(18,809)	(623,830)	(130,502)	(4,899)	(918)	(4,898)	(6,633)
Purchases of minerals-in-place	46	15	92	76	24	5	28	34	508	179	3,891	1,335
Balance, December 31	603,750	281,983	1,499,513	1,135,652	565,010	240,914	1,458,574	1,049,020	482,889	210,497	1,751,880	985,366

(a) The proved gas reserves as of December 31, 2019, 2018 and 2017 include 100,236 MMcf, 106,948 MMcf and 171,623 MMcf, respectively, of gas that the Company expected to be produced and utilized as field fuel. Field fuel is gas consumed to operate field equipment (primarily compressors) rather than being delivered to a sales point.
(b) Production for 2019, 2018 and 2017 includes 11,781 MMcf, 13,690 MMcf and 14,799 MMcf of field fuel, respectively.

Revisions of previous estimates. Revisions of previous estimates for 2019, 2018 and 2017 were comprised of 26 million barrels of oil equivalent ("MMBOE"), 29 MMBOE and 74 MMBOE, respectively, of positive revisions that were primarily attributable to improved performance from horizontal wells placed on production in the Spraberry/Wolfcamp oil field in the Permian Basin. Revisions of previous estimates associated with changes in NYMEX oil and gas prices were 11 MMBOE of negative price revisions in 2019, 20 MMBOE of positive price revisions in 2018 and 52 MMBOE of positive price revisions in 2017. The NYMEX price used for oil and gas reserve preparation, based upon SEC guidelines, was as follows:

	Year Ended December 31,				% Change		
	2019	2018	2017	2016	2019 to 2018	2018 to 2017	2017 to 2016
Oil per Bbl	$ 55.93	$ 65.57	$ 51.34	$ 42.82	(15%)	28%	20%
Gas per Mcf	$ 2.58	$ 3.10	$ 2.98	$ 2.48	(17%)	4%	20%

Extensions and discoveries. Extensions and discoveries for 2019, 2018 and 2017 were primarily comprised of proved reserve additions attributable to the Company's successful horizontal drilling program in the Spraberry/Wolfcamp oil field in the Permian Basin.

Sales of minerals-in-place. Sales of minerals-in-place in 2019 were primarily related to the sale of the Company's Eagle Ford assets and other remaining South Texas assets. In 2018, sales of minerals-in-place were primarily related to the sale of the Company's West Eagle Ford Shale assets, Raton Basin assets and West Panhandle assets. In 2017, sales of minerals-in-place were primarily related to the sale of approximately 20,500 acres in the Martin County region of the Permian Basin. See Note 3 to the accompanying financial statements for additional information.

Purchases of minerals-in-place. Purchases of minerals-in-place during 2017 were primarily attributable to acquisitions in the Company's Spraberry/Wolfcamp oil field in the Permian Basin.

Proved developed and proved undeveloped reserves are as follows:

	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBOE)
Proved Developed Reserves:				
December 31, 2019	571,293	268,468	1,429,417	1,077,997
December 31, 2018	521,579	219,730	1,330,852	963,118
December 31, 2017	442,364	189,434	1,629,451	903,373
Proved Undeveloped Reserves:				
December 31, 2019	32,457	13,515	70,096	57,655
December 31, 2018	43,431	21,184	127,722	85,902
December 31, 2017	40,525	21,063	122,429	81,993

Proved undeveloped reserves activity is as follows (in MBOE):

	Year Ended December 31, 2019
Beginning proved undeveloped reserves	85,902
Revisions of previous estimates	(8,030)
Extensions and discoveries	36,019
Sales of minerals-in-place	(29,295)
Transfers to proved developed	(26,941)
Ending proved undeveloped reserves	57,655

As of December 31, 2019, the Company had 60 proved undeveloped well locations as compared to 134 for both December 31, 2018 and 2017. The Company has no proved undeveloped well locations that are scheduled to be drilled more than five years from their original date of booking.

The changes in proved undeveloped reserves during 2019 were comprised of the following items:

Revisions of previous estimates. Revisions of previous estimates were primarily comprised of eight MMBOE related to negative technical revisions, primarily due to proved undeveloped reserves reclassified to unproved reserves because they are no longer expected to be developed within five years of the date of their initial recognition.

Extensions and discoveries. Extensions and discoveries were primarily comprised of proved reserve additions attributable to the Company's successful horizontal drilling program in the Spraberry/Wolfcamp oil field in the Permian Basin.

Transfers to proved developed. Transfers to proved developed reserves represented those undeveloped proved reserves that moved to proved developed as a result of development drilling. During 2019, the Company incurred $743 million of development costs and developed 31 percent of its 2018 proved undeveloped reserves.

The Company uses both public and proprietary geologic data to establish continuity of the formation and its producing properties. This included seismic data and interpretations (2-D, 3-D and micro seismic); open hole log information (both vertical and horizontally collected) and petrophysical analysis of the log data; mud logs; gas sample analysis; drill cutting samples; measurements of total organic content; thermal maturity; sidewall cores and data measured from the Company's internal core analysis facility. After the geologic area was shown to be continuous, statistical analysis of existing producing wells was conducted to generate areas of reasonable certainty at distances from established production. As a result of this analysis, proved undeveloped reserves for drilling locations within these areas of reasonable certainty were recorded during 2019.

While the Company expects, based on Management's Price Outlooks, that future operating cash flows will provide adequate funding for future development of its proved undeveloped reserves over the next five years, it may also use any combination of internally-generated cash flows, cash and cash equivalents on hand, sales of investments, availability under its credit facility, or external financing sources to fund these and other capital expenditures, including exploratory drilling and acquisitions.

The estimated timing and cash flows of developing proved undeveloped reserves are as follows:

	As of December 31, 2019				
	Estimated Future Production (MBOE)	Future Cash Inflows	Future Production Costs	Future Development Costs	Future Net Cash Flows
			(in millions)		
Year Ended December 31, (a)					
2020	3,482	$ 156	$ 23	$ 269	$ (136)
2021	5,123	218	38	179	1
2022	6,034	242	45	51	146
2023	4,870	182	39	4	139
2024	3,702	134	31	—	103
Thereafter (b)	34,444	1,233	462	5	766
Total	57,655	$ 2,165	$ 638	$ 508	$ 1,019

(a) Production and cash flows represent the drilling results from the respective year plus the incremental effects of proved undeveloped drilling beginning in 2020.
(b) Future development costs represent $5 million of net abandonment costs in years beyond the forecasted years.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is computed by applying commodity prices used in determining proved reserves (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved reserves less estimated future expenditures (based on year-end estimated costs) to be incurred in developing and producing the proved reserves, discounted using a rate of ten percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and gas properties plus available carryforwards and credits and applying the current tax rates to the difference. The discounted future cash flow estimates do not include the effects of the Company's commodity derivative contracts.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of oil and gas properties. Estimates of fair value should also consider probable and possible reserves, anticipated future commodity prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is necessarily subjective and imprecise.

The standardized measure of discounted future cash flows as well as a rollforward in total for each respective year are as follows:

	December 31,		
	2019	2018	2017
		(in millions)	
Oil and gas producing activities:			
Future cash inflows	$ 40,902	$ 43,057	$ 31,716
Future production costs	(19,687)	(16,800)	(13,304)
Future development costs (a)	(1,858)	(1,613)	(1,532)
Future income tax expense	(1,096)	(1,461)	(725)
Standardized measure of future cash flows	18,261	23,183	16,155
Ten percent annual discount factor	(8,527)	(11,850)	(8,004)
Standardized measure of discounted future cash flows	$ 9,734	$ 11,333	$ 8,151

(a) Includes $584 million, $621 million and $639 million of undiscounted future asset retirement expenditures estimated as of December 31, 2019, 2018 and 2017, respectively, using current estimates of future abandonment costs at the end of each year. See Note 9 for additional information.

Changes in Standardized Measure of Discounted Future Net Cash Flows

	Year Ended December 31,		
	2019	2018	2017
		(in millions)	
Oil and gas sales, net of production costs	$ (3,569)	$ (3,673)	$ (2,713)
Revisions of previous estimates:			
Net changes in prices and production costs	(2,935)	2,067	2,690
Changes in future development costs	(454)	(299)	(130)
Revisions in quantities	(174)	(283)	467
Accretion of discount	985	1,163	770
Extensions, discoveries and improved recovery	4,541	5,053	3,454
Development costs incurred during the period	183	177	139
Sales of minerals-in-place	(541)	(287)	(57)
Purchases of minerals-in-place	—	—	10
Change in present value of future net revenues	(1,964)	3,918	4,630
Net change in present value of future income taxes	365	(736)	(669)
	(1,599)	3,182	3,961
Balance, beginning of year	11,333	8,151	4,190
Balance, end of year	$ 9,734	$ 11,333	$ 8,151

Selected Quarterly Financial Results

Selected quarterly financial results are as follows:

	Quarter			
	First	Second	Third	Fourth
	(in millions, except per share data)			
Year Ended December 31, 2019:				
Oil and gas revenues	$ 1,135	$ 1,196	$ 1,235	$ 1,349
Derivative gain (loss), net	$ (13)	$ 43	$ 121	$ (116)
Total revenues and other income	$ 2,413	$ 1,923	$ 2,325	$ 2,643
Total costs and expenses	$ 1,960	$ 2,139	$ 2,022	$ 2,195
Net income (loss) attributable to common stockholders	$ 350	$ (169)	$ 231	$ 344
Net income (loss) per share attributable to common stockholders:				
Basic	$ 2.06	$ (1.01)	$ 1.38	$ 2.06
Diluted	$ 2.06	$ (1.01)	$ 1.38	$ 2.06
Year Ended December 31, 2018:				
Oil and gas revenues	$ 1,266	$ 1,286	$ 1,317	$ 1,122
Derivative gain (loss), net	$ (208)	$ (358)	$ (135)	$ 409
Total revenues and other income	$ 2,150	$ 2,111	$ 2,476	2,677
Impairment of oil and gas properties (a)	$ —	$ 77	$ —	$ —
Total costs and expenses	$ 1,922	$ 2,029	$ 1,947	$ 2,265
Net income attributable to common stockholders	$ 178	$ 66	$ 411	$ 324
Net income per share attributable to common stockholders:				
Basic	$ 1.04	$ 0.38	$ 2.40	$ 1.89
Diluted	$ 1.04	$ 0.38	$ 2.39	$ 1.89

(a) During the second quarter of 2018, the Company impaired the carrying value of proved properties and related assets in the Raton Basin gas field (sold July 2018).

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of disclosure controls and procedures. The Company's management, with the participation of its principal executive officer and principal financial officer, have evaluated, as required by Rule 13a-15(b) under the Securities Exchange Act of 1934 ("the Exchange Act"), the effectiveness of the Company's disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of the end of the period covered by this Report. Based on that evaluation, the principal executive officer and principal financial officer concluded that the Company's disclosure controls and procedures were effective, as of the end of the period covered by this Report, in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, including that such information is accumulated and communicated to the Company's management, including the principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Changes in internal control over financial reporting. There have been no changes to the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the three months ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed by or under the supervision of the Company's principal executive officer and principal financial officer and effected by the board of directors, management and other personnel 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.

The Company's management, with the participation of its principal executive officer and principal financial officer assessed the effectiveness, as of December 31, 2019, of the Company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in "Internal Control — Integrated Framework (2013)," issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting at a reasonable assurance level as of December 31, 2019, based on those criteria.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2019. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2019, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Pioneer Natural Resources Company

Opinion on Internal Control over Financial Reporting

We have audited Pioneer Natural Resources Company's internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Pioneer Natural Resources Company (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of Pioneer Natural Resources Company as of December 31, 2019 and 2018, and the related consolidated statements of operations, equity and cash flows for each of the three years in the period ended December 31, 2019, and the related notes and our report dated February 24, 2020 expressed an unqualified opinion thereon.

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/ Ernst & Young LLP

Dallas, Texas
February 24, 2020

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The names of the executive officers of the Company and their ages, titles and biographies as of the date hereof are incorporated by reference from Part I of this Report. The other information required in response to this Item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held in May 2020 and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this Item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held in May 2020 and is incorporated herein by reference.

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

Securities Authorized for Issuance under Equity Compensation Plans

Summarized information about the Company's equity compensation plans is as follows:

	As of December 31, 2019		
	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in first column)
Equity compensation plans approved by security holders:			
2006 Long-Term Incentive Plan (b)(c)	121,953	$ 106.04	4,228,118
Employee Stock Purchase Plan (d)	—	—	193,062
	121,953	$ 106.04	4,421,180

(a) There are no outstanding warrants or equity rights awarded under the Company's equity compensation plans.

(b) The number of remaining securities available for future issuance under the Company's 2006 Long-Term Incentive Plan is based on the aggregate securities authorized for issuance under the plan of 12,600,000. Awards under the 2006 Long-Term Incentive Plan can be in the form of stock options, stock appreciation rights, performance units, restricted stock and restricted stock units.

(c) The number of securities remaining for future issuance has been reduced by the maximum number of shares that could be issued pursuant to outstanding grants of performance units as of December 31, 2019.

(d) The number of remaining securities available for future issuance under the Company's Employee Stock Purchase Plan is based on the aggregate securities authorized for issuance under the plan of 1,250,000.

See Note 8 of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

The remaining information required in response to this Item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held in May 2020 and is incorporated herein by reference.

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

The information required in response to this Item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held in May 2020 and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required in response to this Item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held in May 2020 and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Listing of Financial Statements

Financial Statements

The following consolidated financial statements of the Company are included in "Item 8. Financial Statements and Supplementary Data:"

- Report of Independent Registered Pubic Accounting Firm
- Consolidated Balance Sheets as of December 31, 2019 and 2018
- Consolidated Statements of Operations for the Years Ended December 31, 2019, 2018 and 2017
- Consolidated Statements of Equity for the Years Ended December 31, 2019, 2018 and 2017
- Consolidated Statements of Cash Flows for the Years Ended December 31, 2019, 2018 and 2017
- Notes to Consolidated Financial Statements
- Unaudited Supplementary Information

(b) Exhibits

The exhibits to this Report that are required to be filed pursuant to Item 15(b) are included in the Company’s Form 10-K filed with the SEC on February 24, 2020.

(c) Financial Statement Schedules

No financial statement schedules are required to be filed as part of this Report or they are inapplicable.

ITEM 16. FORM 10-K SUMMARY

None.

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SHAREHOLDER INFORMATION

STOCK EXCHANGE LISTING – COMMON STOCK

New York Stock Exchange: PXD

CORPORATE INFORMATION

Pioneer Natural Resources Company
777 Hidden Ridge
Irving, TX 75038
(972) 444-9001
pxd.com

STOCK TRANSFER AGENT AND REGISTRAR

Communication concerning the transfer or exchange of shares, dividend payments, lost certificates or change of address should be directed to:

Continental Stock Transfer & Trust Company
1 State St., 30th Floor
New York, NY 10004-1561
(888) 509-5581
continentalstock.com
pioneer@continentalstock.com

ANNUAL MEETING

The Annual Meeting of Stockholders will be held on Thursday, May 21, 2020, at 9:00 a.m. Central Time. See investors.pxd.com for details.

INFORMATION REQUESTS

To receive additional copies of the Annual Report on Form 10-K as filed with the SEC or to obtain other Pioneer publications, please contact:

Pioneer Natural Resources Company
ATTN: Investor Relations
777 Hidden Ridge
Irving, TX 75038
(972) 969-3583
ShareholderQuestions@pxd.com

INVESTOR RELATIONS AND MEDIA CONTACTS

Shareholders, portfolio managers, brokers and securities analysts seeking information concerning Pioneer's operations or financial results are encouraged to contact Neal Shah, Vice President, Investor Relations, at (972) 969-3900. Media inquiries should be directed to Tadd Owens, Vice President, Communications and Government Relations, at (972) 969-5760.

Return on Capital Employed (ROCE) is a non-GAAP financial measure. As used by the Company, ROCE is net income adjusted for tax-effected noncash mark-to-market (MTM) adjustments, unusual items and interest expense divided by the summation of average total equity (adjusted for net noncash MTM adjustments, unusual items and interest expense) and average net debt. The Company believes ROCE is a good indicator of long-term performance, both absolute and relative to the Company's peers. ROCE is a measure of the profitability of the Company's capital employed in its business compared with that of its peers.

	2019 ($ Millions)	2018 ($ Millions)	2017 ($ Millions)
Net Income	**$756**	**$975**	**$833**
Noncash MTM adjustments:			
South Texas contingent consideration loss	35	—	—
Derivative (gain) loss, net	10	(211)	112
ProPetro stock gain	(11)	—	—
Unusual Items:			
Net (gain) loss on asset divestitures	330	(226)	(124)
Corporate restructuring charges	130	—	—
Asset divestiture-related charges	57	189	182
Sand mine decommissioning-related charges	37	351	—
Corporate headquarters move-related costs	32	—	—
Excess tax benefits and reduction in deferred tax liability	—	—	(633)
After-tax adjusted income excluding noncash MTM adjustments and unusual items	**1,376**	**1,078**	**370**
After-tax interest expense	**94**	**98**	**98**
ROCE Earnings	$1,470	$1,176	$468

	As of December 31,		
	2019	**2018**	**2017**
Average total equity	$12,472	$11,796	$10,663
Average net debt	1,275	724	396
Average capital employed	$13,747	$12,520	$11,059
ROCE%	**11%**	**9%**	**4%**

PIONEER
NATURAL RESOURCES

NYSE: PXD | PXD.COM

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Irving, TX 75038 | (972) 444-9001