Setting the Course.

PARSLEY ENERGY / 2018 ANNUAL REPORT

PARSLEY

NYSE: PE

Parsley Energy has a strong heritage and a bright future.

PARSLEY ENERGY MANAGEMENT TEAM

DEAR SHAREHOLDERS

Parsley Energy celebrated its ten-year anniversary in 2018 with one of our strongest operational performances to date, as we both expanded operating margins to Company-record levels and greatly enhanced our operational efficiency. As we set the course for 2019, our top priorities are demonstrating meaningful progress toward sustainable free cash flow generation and recording a tangible year-over-year improvement in capital efficiency. Underpinning these key objectives is a deliberate shift in our development approach to prioritize project-level rate of return, a strategy enabled by our deep, high-quality inventory.

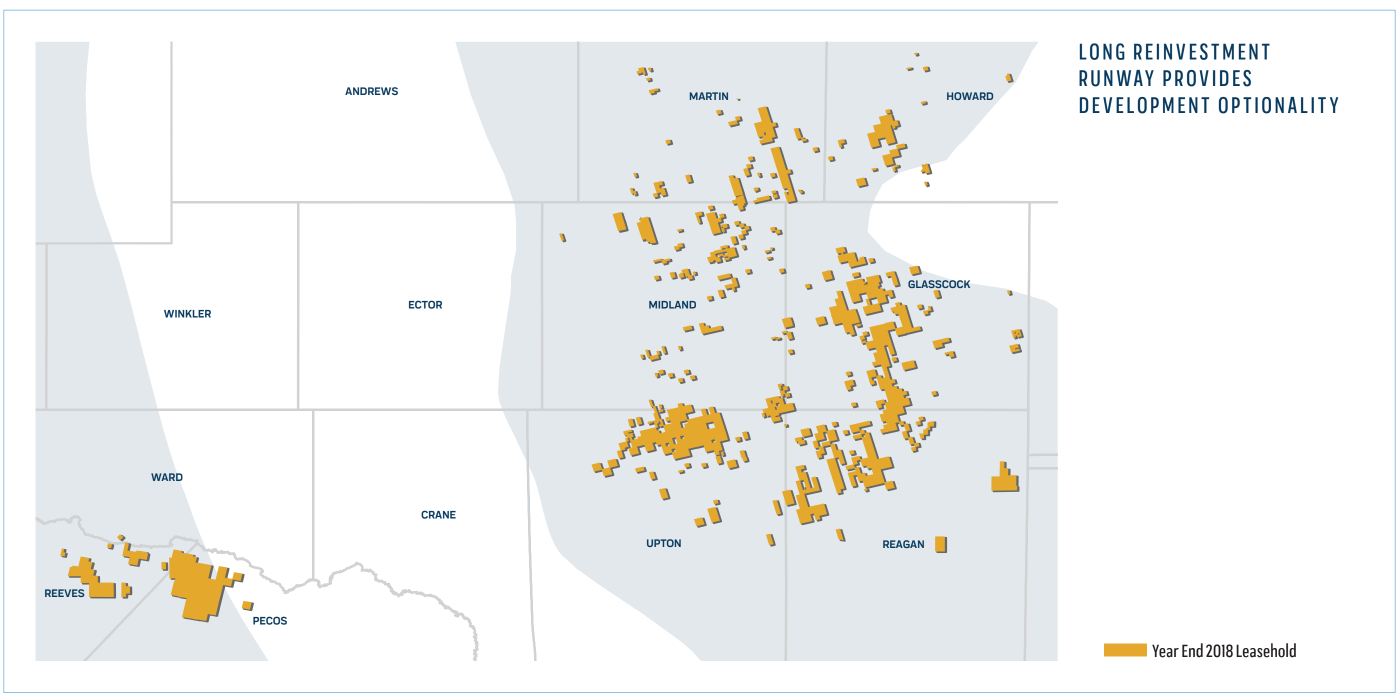
Over the past decade, technological innovation sparked a shale revolution in the United States, and Parsley helped push that leading edge. Bryan Sheffield started this company in the summer of 2008 with little more than a handful of operating contracts for a few dozen vertical wells. With Bryan's visionary leadership and that initial toehold, we worked to build out a talented team and achieve sufficient scale in the most attractive basin in the country. Parsley Energy now operates as a publicly traded company with an $8 billion enterprise value and runs 12 horizontal rigs across an expansive 192,000 net acre footprint in the heart of the Permian Basin. Our team is committed to the communities in which we operate and proud to be at the heart of the region that produces the energy needed to power our daily lives. Simply put, we scaled up rapidly in short order and built a disciplined and responsible company that has a bright future.

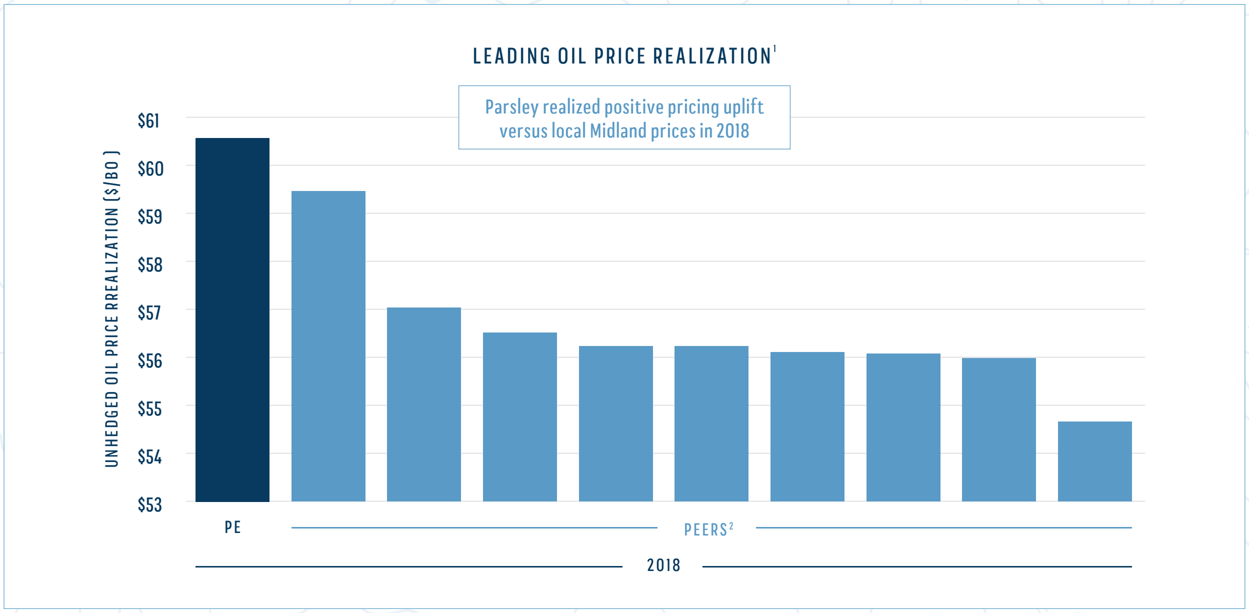
Having focused on building scale in 2017, our 2018 program centered on a steady development pace that prioritized operational continuity and helped make us a more efficient organization. We took meaningful strides forward in our drilling and completion efficiency, with footage per operational day up significantly year over year. In fact, we set a new Company record for completion efficiency in 3Q18 and then bested that effort in 4Q18, highlighting our sustained operational momentum. Overall, we covered more ground in less time in 2018 and recaptured the top-rate operational efficiency Parsley expects to deliver.

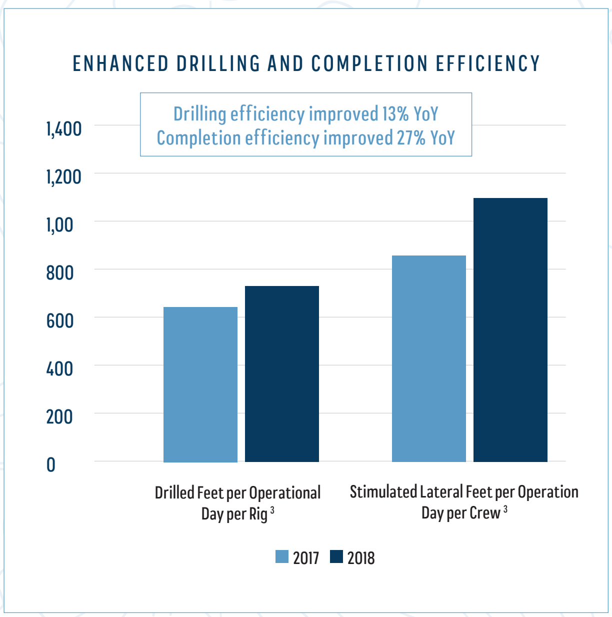
Parsley's operational momentum in 2018 coincided with a volatile time for oil prices, especially in the Permian. However, it was in these tumultuous times that the bench strength we have assembled throughout the organization shone through. As we built scale during 2017, our marketing team worked on agreements to ensure our products had both dependable flow assurance and pricing diversification. This proactive marketing strategy paid dividends throughout 2018 as we successfully navigated a challenging midstream takeaway situation without interruption and delivered a realized oil price that comfortably outpaced both our peers and local Midland prices.

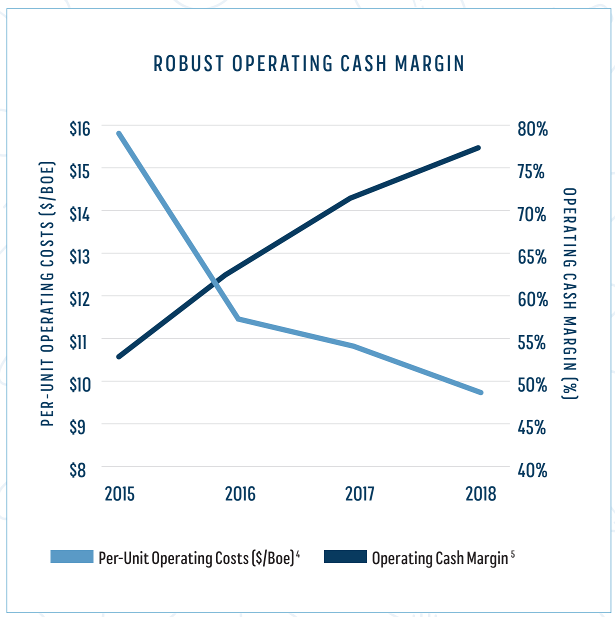
We also remain sharply focused on costs, and thanks to a tireless effort by our teams in the field and the growing benefits of scale, we lowered our per unit lease operating and cash G&A expense by a combined 17% year-over-year. Layering this stringent cost control on top of strong realized pricing produced robust operating cash margins, and Parsley set a company-record on this front during 2018. Coupling these healthy operating margins with differentiated organic oil production growth resulted in a near doubling of our cash flow per share in 2018.

We continue to work from a position of financial strength, with low leverage and ample liquidity that was further bolstered by disciplined pruning of low priority assets through the year and an opportunistic divestiture at year end. In addition, by hedging a higher percentage of our oil production than many of our peers, we are able to better protect our cash flow and balance sheet from commodity price downside, while preserving meaningful upside in a stronger oil price environment.









[1] Data based on publicly available company filings. PE realized prices shown net of gathering fees.

[2] Peers include CDEV, CPE, CXO, FANG, HK, JAG, LPI, MTDR, and SM. Permian only oil realizations shown where applicable.

[3] Operational day measured as days equipment is active and does not include mobilization or other idle time.

[4] Per-unit operating costs include lease operating expenses, cash based general and administrative expenses (exclusive of stock-based compensation), and production and ad valorem taxes. Transportation and processing costs are excluded from 2018 to normalize for the period over period impacts of adopting ASC 606.

[5] Operating cash margin percentage is a non-GAAP financial measure. For a reconciliation to the most directly comparable GAAP financial measure, please see the section entitled "Operating Cash Margin Reconciliation" at the end of this annual report or the supplementary slides of our latest investor presentation posted on our website. Operating cash margin percentage calculated as operating cash margin per Boe divided by realized price per Boe excluding hedges. As used by the company, operating cash margin is defined as realized price per Boe excluding hedges less per-unit operating costs including transportation and processing costs.

"Our team is committed to the communities in which we operate and proud to be at the heart of the region that produces the energy needed to power our daily lives."

— **MATT GALLAGHER**
PRESIDENT AND CEO

PARSLEY ENERGY
EXECUTIVE OFFICERS

Parsley's commitment to positive community stewardship remained steadfast in 2018, exemplified by joining the Permian Strategic Partnership, a group dedicated to the future of the Permian Basin. Our efforts as a responsible operator continued to resonate throughout the organization with the completion of a promising water recycling project and the addition of new technologies to help prevent leaks and spills, reduce emissions, and additional efforts to minimize our environmental footprint.

I am proud of our team's accomplishments in 2018, but recognize our work is far from complete. We operate in a dynamic landscape that can, and does change quickly. Therefore, it is incumbent upon us as operators to be adaptive and nimble. Yet at all times and in all environments, we must be focused on the returns of each incremental dollar invested.

For 2019, we have committed to a disciplined development budget that reduces our baseline activity from sixteen rigs and five frac crews to twelve to fourteen rigs and three to four frac crews. This budget was designed to ensure Parsley takes another major step forward on our path to self-funded growth this year in any commodity price environment, while continuing to build upon hard-earned operational efficiency gains.

One of the cornerstones of our 2019 development approach is a deliberate shift to prioritize project level rate-of-return over project level net present value, a strategy enabled by our deep, high-quality inventory. In practice, this means high-grading our well selection process, concentrating more activity in our highest return areas, and optimizing completions and spacing patterns. Overall, it means better wells, shorter payback periods and increasing cash flow velocity. This approach will have a compounding effect for years to come.

Ultimately, we believe this returns-focused approach to project selection will facilitate two key outcomes at the corporate level for Parsley. First, it accelerates our progress toward self-funded growth. We now expect to turn the corner to sustainable free cash flow during the fourth quarter of 2019 at an oil price in the low $50s. An oil price higher than that would simply expand that free cash flow profile and accelerate shareholder return initiatives.

We have the core inventory depth and the short cycle projects that allow us to adapt and be nimble. This combination lets us set a returns-focused course for 2019 that helps achieve our second key targeted outcome - a tangible 8-10%+ year-over-year improvement in capital efficiency. We expect both productivity gains and capex savings to drive this improvement. Our team stands poised to deliver on an advantaged program in 2019, paving a path to the prize we are all playing for as shareholders – sustainable free cash flow and top-tier corporate returns.

Bryan set us on a path to success and Parsley Energy is built to last. I am excited to help write the next chapter for Parsley and be a link in the vital energy industry chain that fuels our daily life. We have set the course for Parsley Energy in a financially and environmentally responsible way, and we appreciate your continued support as we look forward to executing our 2019 action plan.

Matt Gallagher
President and Chief Executive Officer

Operating cash margin is a non-GAAP financial measure. As used by the Company, operating cash margin is defined as realized price per Boe excluding hedges less per-unit operating costs including transportation and processing costs.

Free cash flow is a non-GAAP financial measure. As used by the Company, free cash flow is defined as cash flow from operations before changes in operating assets and liabilities less development capital expenditures.

MANAGEMENT

EXECUTIVE OFFICERS

MATT GALLAGHER
President and Chief Executive Officer

BRYAN SHEFFIELD
Executive Chairman

DAVID DELL'OSSO
Executive Vice President –
Chief Operating Officer

RYAN DALTON
Executive Vice President –
Chief Financial Officer

COLIN ROBERTS
Executive Vice President –
General Counsel

SENIOR VICE PRESIDENTS

CECILIA CAMARILLO
Senior Vice President –
Accounting

MIKE HINSON
Senior Vice President –
Corporate Development, Co-founder

THOMAS LAYMAN
Senior Vice President –
Geoscience

STEPHANIE REED
Senior Vice President –
Land and Marketing

PAUL TREADWELL
Senior Vice President –
Production Operations, Co-founder

VICE PRESIDENTS

MARK BROWN
Vice President –
Security and Risk Management

CARRIE ENDORF
Vice President –
Reservoir Engineering and Planning

ROB HEMBREE
Vice President –
Information Technology

JODY JORDAN
Vice President –
Marketing

LANDON MARTIN
Vice President –
Drilling Engineering

KRISTIN McCLURE
Vice President –
Human Resources

MARK TIMMONS
Vice President –
Field Operations

BOARD OF DIRECTORS

BRYAN SHEFFIELD
Executive Chairman and
Chairman of the Board

MATT GALLAGHER
President, Chief Executive Officer,
and Director

A.R. ALAMEDDINE [2,5]
Director

RONALD BROKMEYER [1,2,4]
Director

WILLIAM L. BROWNING [1,3]
Director

DR. HEMANG DESAI [1,2]
Director

KAREN HUGHES [2,3]
Director

DAVID SMITH [3]
Director

JERRY WINDLINGER [2,3,4]
Director

1 Member of the Audit Committee

2 Member of the Compensation Committee

3 Member of the Nominating and Governance Committee

4 Member of the Reserves Committee

5 Lead Director

CONTACT INFORMATION

AUSTIN OFFICE
303 Colorado Street • Suite 3000
Austin, TX 78701
737-704-2300

MIDLAND OFFICE
1703 E. County Road 120
Midland, TX 79706
432-818-2100

COMMON STOCK

The company's Class A common stock is traded on the New York Stock Exchange under the symbol PE.

INDEPENDENT AUDITOR

KPMG LLP
2323 Ross Avenue • Suite 1400
Dallas, TX 75201

TRANSFER AGENT

For shareholder questions regarding transfer of shares, lost stock certificates, duplicate mailings, change of address or other similar matters, please contact our Transfer Agent:

American Stock Transfer & Trust Company
6201 15th Avenue, Brooklyn, NY 11219
800-937-5449
info@astfinancial.com

INDEPENDENT PETROLEUM ENGINEERS

Netherland, Sewell & Associates, Inc.
2100 Ross Avenue • Suite 2200
Dallas, TX 75201

VISIT OUR WEBSITE

www.parsleyenergy.com

INVESTOR RELATIONS

Shareholders, brokers, securities analysts, portfolio managers seeking information about the company may email us at ir@parsleyenergy.com or call:
Kyle Rhodes
Director of Investor Relations
512-505-5199

ANNUAL MEETING

The Annual Meeting of Stockholders will be held on Friday, May 24, 2019, at 8:00 a.m. Central Time at The W Austin Hotel 200 Lavaca Street, Austin, TX 78701

2018 ANNUAL REPORT

FORM 10-K

PARSLEY

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2018
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: 001-36463

PARSLEY ENERGY, INC.

(Exact name of registrant as specified in its charter)

Delaware	**46-4314192**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
303 Colorado Street, Suite 3000 Austin, Texas	**78701**
(Address of principal executive offices)	**(Zip Code)**

(737) 704-2300
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Class A Common Stock, $0.01 par value	**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 during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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 Exchange Act). Yes ☐ No ☒

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2018 was approximately $8,342,325,852 based on the closing price as reported on the New York Stock Exchange.

As of February 27, 2019, the registrant had 280,162,552 shares of Class A common stock and 36,547,731 shares of Class B common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement for the 2019 Annual Meeting of Stockholders, to be filed no later than 120 days after the end of the fiscal year to which this Annual Report on Form 10-K relates, are incorporated by reference into Part III of this Annual Report on Form 10-K.

PARSLEY ENERGY, INC.
FORM 10-K
ANNUAL PERIOD ENDED DECEMBER 31, 2018

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in or incorporated by reference into this Annual Report on Form 10-K (this "Annual Report") that express a belief, expectation, or intention, or that are not statements of historical fact, are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These forward-looking statements include statements, projections and estimates concerning the Company's operations, performance, business strategy, oil and natural gas reserves, drilling program, capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "intend," "potential," "could," "may," "foresee," "plan," "goal" or other words that convey the uncertainty of future events or outcomes. Forward-looking statements are not guarantees of performance. We have based these forward-looking statements on our current expectations and assumptions about future events. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Actual results may differ materially from those implied or expressed by the forward-looking statements. These forward-looking statements speak only as of the date of this Annual Report, or if made earlier, as of the date they were made. We disclaim any obligation to update or revise these statements unless required by law, and we caution you not to unduly rely on them. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks discussed under "Item 1A. Risk Factors," as well as those factors summarized below.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- exploration and development drilling prospects, inventories, projects and programs;
- ability to replace the reserves we produce through drilling and property acquisitions;
- financial strategy, liquidity and capital required for our development program;
- realized oil, natural gas and natural gas liquids ("NGLs") prices;
- timing and amount of future production of oil, natural gas and NGLs;
- hedging strategy and results;
- future drilling plans;
- competition and government regulations;
- ability to obtain permits and governmental approvals;
- pending legal or environmental matters;
- marketing of oil, natural gas and NGLs;
- leasehold, minerals or business acquisitions or divestitures;
- costs of developing our properties;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this Annual Report that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration, development, production, gathering and sale of oil, natural gas and NGLs. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures, and the other risks described under "Item 1A. Risk Factors."

Additionally, we caution you that reserve engineering is a process of estimating underground accumulations of oil, natural gas and NGLs that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions could change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil, natural gas and NGLs that are ultimately recovered.

Should one or more of the risks or uncertainties described in this Annual Report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. As a result, you should not place undue reliance on these forward-looking statements.

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

GLOSSARY OF CERTAIN TERMS AND CONVENTIONS USED HEREIN

The terms defined in this section are used throughout this Annual Report:

(1) *Bbl.* One stock tank barrel, of 42 U.S. gallons liquid volume, used in reference to crude oil, condensate or natural gas liquids.

(2) *Boe*. One barrel of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.

(3) *Boe/d.* One barrel of oil equivalent per day.

(4) *British thermal unit or Btu*. The heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

(5) *Free cash flow.* A non-GAAP financial measure, which we define as cash flow from operations before changes in operating assets and liabilities less development capital expenditures.

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

(7) *Condensate*. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

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

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

(10) *Economically producible*. A resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. For a complete definition of economically producible, refer to the SEC's Regulation S-X, Rule 4-10(a)(10).

(11) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and natural gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the related property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

- (i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are referred to as geological and geophysical costs or G&G costs.
- (ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
- (iii) Dry hole contributions and bottom hole contributions.
- (iv) Costs of drilling and equipping exploratory wells.
- (v) Costs of drilling exploratory-type stratigraphic test wells.

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

(13) *Extension well*. A well drilled to extend the limits of a known reservoir.

(14) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(15) *Formation*. A layer of rock which has distinct characteristics that differ from nearby rock.

(16) *GAAP*. Accounting principles generally accepted in the United States.

(17) *Gross acres or gross wells*. The total acres or wells, as the case may be, in which an entity owns a working interest.

(18) *Horizontal drilling*. A drilling technique where a well is drilled vertically to a certain depth and then drilled laterally within a specified target zone.

(19) *Identified drilling locations*. Potential drilling locations specifically identified by our management based on evaluation of applicable geologic and engineering data accrued over our multi-year historical drilling activities.

(20) *Lease operating expense*. All direct and allocated indirect costs of lifting hydrocarbons from a producing formation to the surface constituting part of the current operating expenses of a working interest. Such costs include labor, superintendence, supplies, repairs, maintenance, allocated overhead charges, workover, insurance and other expenses incidental to production, but exclude lease acquisition or drilling or completion expenses.

(21) *LIBOR.* London Interbank Offered Rate.

(22) *MBbl.* One thousand barrels of crude oil, condensate or NGLs.

(23) *MBoe.* One thousand barrels of oil equivalent.

(24) *Mcf.* One thousand cubic feet of natural gas.

(25) *MMBoe.* One million barrels of oil equivalent.

(26) *MMBtu.* One million British thermal units.

(27) *MMcf.* One million cubic feet of natural gas.

(28) *Natural gas liquids or NGLs*. The combination of ethane, propane, butane, isobutane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

(29) *Net acres or net wells*. The percentage of total acres or wells, as the case may be, an owner has out of a particular number of gross acres or wells. For example, an owner who has 50% interest in 100 gross acres owns 50 net acres.

(30) *NYMEX.* The New York Mercantile Exchange.

(31) *Operator.* The entity responsible for the exploration, development and production of a well or lease.

(32) *PE Units*. The single class of units that represents membership interests in Parsley Energy, LLC.

(33) *Proved developed reserves*. Proved reserves that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well; or

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

(34) *Proved reserves*. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence, within a reasonable time. For a complete definition of proved oil and natural gas reserves, refer to the SEC's Regulation S-X, Rule 4-10(a)(22).

(35) *Proved undeveloped reserves or PUDs*. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. The following rules apply to PUDs:

(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 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; and

(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.

(36) *Reasonable certainty*. A high degree of confidence. For a complete definition of reasonable certainty, refer to the SEC's Regulation S-X, Rule 4-10(a)(24).

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

(38) *Reliable technology*. A grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

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

(40) *Reservoir*. A porous and permeable underground formation containing a natural accumulation of producible hydrocarbons that is confined by impermeable rock or water barriers and is separate from other reservoirs.

(41) *SEC*. The United States Securities and Exchange Commission.

(42) *Spacing*. The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, *e.g.*, 40-acre spacing, and is often established by regulatory agencies.

(43) *Undeveloped acreage*. Leased acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or natural gas regardless of whether such acreage contains proved reserves.

(44) *Wellbore*. The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

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

(46) *Workover.* Operations on a producing well to restore or increase production.

(47) *WTI*. West Texas Intermediate crude oil, which is a light, sweet crude oil, characterized by an American Petroleum Institute gravity, or API gravity, between 39 and 41 and a sulfur content of approximately 0.4 weight percent that is used as a benchmark for other crude oils.

PART I

ITEM 1. BUSINESS

Overview

Parsley Energy, Inc. (either individually or together with its subsidiaries, as the context requires, "we," "us," "our" or the "Company") is an independent oil and natural gas company focused on the acquisition, development, exploration and production of unconventional oil and natural gas properties in the Permian Basin. The Permian Basin is located in west Texas and southeastern New Mexico and is characterized by high oil and liquids-rich natural gas content, multiple vertical and horizontal target horizons, extensive production histories, long-lived reserves and historically high drilling success rates. Our properties are located in two sub areas of the Permian Basin, the Midland and Delaware Basins, where, given the associated returns, we focus predominantly on horizontal development drilling.

As of December 31, 2018, we had an interest in 571 gross (442.7 net) productive horizontal wells, of which 467 gross (357.5 net) wells are in the Midland Basin and 104 gross (85.2 net) wells are in the Delaware Basin. As of December 31, 2018, we operated 453 gross (425.3 net) of these horizontal wells and had the rights to develop 267,143 gross (198,946 net) acres in the Permian Basin, with approximately 218,525 gross (154,107 net) acres located in the Midland Basin and 48,618 gross (44,839 net) acres located in the Delaware Basin. We intend to grow our reserves and production through the drilling and development of our multi-year inventory of identified drilling locations.

At December 31, 2018, our estimated proved oil, natural gas and NGLs reserves were 521.7 MMBoe based on an internal reserve report prepared by our internal staff of petroleum engineers and audited by Netherland, Sewell & Associates, Inc. ("NSAI"), our independent third-party petroleum consulting firm. Of these reserves, approximately 60% are classified as proved developed producing. Based on this report, at December 31, 2018, our proved developed reserves were approximately 55% oil, 19% natural gas and 26% NGLs. These calculated percentages include proved developed non-producing reserves.

Our 2019 budget for capital development expenditures is approximately 1,350.0 million to $1,550.0 million, approximately 85% of which is expected to be used for drilling and completions and approximately 15% of which is expected to be used for infrastructure and other expenditures. We expect approximately 30% to 35% of the total budget to be associated with drilling and completions for proved undeveloped reserves as of December 31, 2018. Our capital budget excludes any amounts that may be paid for acquisitions. For the years ended December 31, 2018 and 2017, our aggregate drilling and completion expenditures were $1,510.1 million and $1,049.6 million, respectively, and our infrastructure and other expenditures were $252.1 million and $157.8 million, respectively, for totals of $1,762.2 million and $1,207.4 million, respectively. Of these totals, $308.1 million and $65.1 million were associated with drilling, completions and facility buildout for proved undeveloped reserves for the years ended December 31, 2018 and 2017, respectively. The amount and timing of 2019 capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned 2019 capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners.

Our Business Strategy

Our business strategy is to increase stockholder value through the following:

- ***Achieve free cash flow generation through capital efficient development activity***. We intend to selectively develop our acreage base and grow production with a strong commitment to capital discipline. By pursuing drilling opportunities offering competitive returns and prioritizing project level rate of return, which is enabled by our deep, high-quality inventory and resource potential, we expect to improve our capital and operational efficiency. In line with these priorities, our 2019 budget contemplates a significant reduction in our outspend, under any commodity price environment, as compared to our 2018 outspend. We believe this balanced and disciplined approach to development will enable sustainable free cash flow generation and favorable returns on invested capital, while, at the same time, increasing our reserves and production.

- ***Enhance returns through continued improvement in operational and cost efficiencies***. We currently operate approximately 96% of our 2018 daily horizontal production and intend to maintain operational control of substantially all of our producing properties. We believe that retaining control of our production will enable us to more efficiently manage the pace and costs of drilling and completion activities, increase recovery rates, lower well costs, improve drilling performance and increase ultimate hydrocarbon recovery through optimization of our drilling and completion techniques. Our management team regularly evaluates our operating results against those of other operators in the area in an effort to improve our performance and implement best practices.

- ***Optimizing and high-grading our leasehold position***. We regularly evaluate and complete acquisitions, divestitures and exchanges of undeveloped leasehold and producing properties that meet our strategic and financial objectives in the ordinary course of our business. We expect these strategic transactions will help us consolidate our core acreage, drill wells with longer lateral lengths, leverage existing infrastructure, maintain adequate inventory life and achieve economies of scale, while divesting of non-core properties that are less economically competitive within our portfolio. We have a proven history of optimizing our leasehold position in the Permian Basin by concentrating our ownership in operated properties with substantial oil-weighted resource potential, and we believe we can continue to economically and efficiently optimize our acreage position to further enhance project returns.

- ***Maintain financial flexibility***. We intend to maintain a conservative financial position to allow us to develop our exploration, drilling and production activities and maximize the present value of our oil-weighted resource potential. Until we achieve self-funded growth through sustainable free cash flow generation, we anticipate funding our growth with a combination of cash on hand, cash flow from operations, borrowings under our revolving credit agreement ("Revolving Credit Agreement"), and strategic divestitures of non-core properties. In limited circumstances, we may also access the capital markets. As of December 31, 2018, we had approximately $1,154.5 million of liquidity, including $163.2 million of cash and cash equivalents. The borrowing base under our Revolving Credit Agreement currently stands at $2.3 billion, with a commitment level of $1.0 billion. As of December 31, 2018, there were no borrowings outstanding and $8.7 million in letters of credit outstanding under our Revolving Credit Agreement as of December 31, 2018, resulting in availability of $991.3 million. Consistent with our disciplined approach to financial management, we have an active commodity hedging program through which we seek to hedge a meaningful portion of our expected oil production, reducing our exposure to downside commodity price fluctuations and enabling us to protect cash flows and maintain liquidity to fund our capital program and investment opportunities.

Our Strengths

We believe that the following strengths will help us achieve our business goals:

- ***Extensive set of reinvestment opportunities.*** We believe that the majority of our acreage offers stacked pay potential to develop oil and natural gas from several prospective target zones, including, depending on the area, the Spraberry, Wolfcamp, and Bone Spring, and further, that some of these target zones may be characterized by sufficient thickness and resource potential to accommodate more than one pay interval per zone. Through December 31, 2018, we had placed on production 357 gross (326.6 net) horizontal wells in the Midland Basin and 70 gross (67.7 net) horizontal wells in the Delaware Basin. We believe this historical development activity only represents a fraction of our future development potential, providing an extensive inventory of reinvestment opportunities.

- ***Established resource base and acreage position in the core of the Permian Basin***. Our production is exclusively from the Permian Basin in west Texas, an area that has supported oil and gas production since the 1940s. The Permian Basin has well established infrastructure from historical operations, and we believe it also benefits from a relatively stable regulatory environment that has been established over time. As of December 31, 2018, our estimated total proved reserves were composed of approximately 57% oil and 18% natural gas, and 25% NGLs.

- ***Incentivized management team with substantial technical and operational expertise***. Our management team has a proven track record of executing on multi-rig development drilling programs and has extensive experience in the Spraberry and Wolfberry Trends of the Permian Basin. Our management team has an average of 21 years of experience. We have also assembled a robust technical team of petroleum engineers and geologists with an average of 12 years of experience, which we believe will be of strategic importance as we continue to expand our future exploration and development plans. As of December 31, 2018, our executive officers held voting power over approximately 12.4% of our outstanding equity interests. We believe the existence of this significant management ownership position provides meaningful incentive to increase the value of our business for the benefit of all stockholders.

- ***Operating control over substantially all our horizontal production***. As of December 31, 2018, we operated approximately 96% of our 2018 daily horizontal production. We believe that maintaining control of our production enables us to dictate the pace of development and better manage the cost, type and timing of exploration and development activities.

- ***Conservative balance sheet***. We expect to maintain financial flexibility that will allow us to continue our development activities while pursuing selective acquisitions, divestitures and exchanges. As of December 31, 2018, we had $991.3 million of available borrowing capacity under our Revolving Credit Agreement, with no borrowings currently outstanding thereunder. We believe this borrowing capacity, along with cash on hand and cash flow from operations will provide us with sufficient liquidity to execute our current capital program.

Organizational Structure

We are a holding company that was incorporated as a Delaware corporation on December 11, 2013 for the purpose of facilitating our initial public offering (the "IPO") and to become the sole managing member of Parsley Energy, LLC ("Parsley LLC"). As of December 31, 2018, our sole material asset consists of 280,205,293 PE Units and, as sole managing member, we hold a controlling equity interest in Parsley LLC.

Prior to the completion of the IPO, the limited liability company agreement of Parsley LLC (as subsequently amended, the "Parsley LLC Agreement") was amended and restated to modify its capital structure by replacing the different classes of interests previously held by Parsley LLC owners with a single new class of units called "PE Units." In addition, each holder of PE Units ("PE Unit Holder") received one share of our Class B common stock, par value $0.01 per share ("Class B common stock"). Pursuant to the Parsley LLC Agreement, the PE Unit Holders generally have the right to exchange (the "Exchange Right") their PE Units (and a corresponding number of shares of Class B common stock) for shares of our Class A common stock, par value $0.01 per share ("Class A common stock") at an exchange ratio of one share of Class A common stock for each PE Unit (and a corresponding number of shares of Class B common stock) exchanged (subject to conversion rate adjustments for stock splits, stock dividends and reclassifications), or, if either we or Parsley LLC so elects, cash (the "Cash Option"). In addition, in connection with the IPO, on May 29, 2014, we entered into a Tax Receivable Agreement (the "TRA") with Parsley LLC and the initial PE Unit Holders and certain other holders of equity in us (each such person, a "TRA Holder"). This agreement generally provides for the payment by us to a TRA Holder of 85% of the net cash savings, if any, in U.S. federal, state or local income tax that we actually realize (or are deemed to realize in certain circumstances) in periods after our IPO as a result of (i) any tax basis increases resulting from the contribution in connection with our IPO by such TRA Holder of all or a portion of its PE Units to us in exchange for shares of Class A common stock, (ii) the tax basis increases resulting from the exchange by such TRA Holder of PE Units for shares of Class A common stock pursuant to the Exchange Right (or resulting from an exchange of PE Units for cash pursuant to the Cash Option) and (iii) imputed interest deemed to be paid by us as a result of, and additional tax basis arising from, any payments we make under the TRA. We will retain the benefit of the remaining 15% of these cash savings.

As a result of the IPO and the related reorganization transactions, we became the sole managing member of and have a controlling equity interest in Parsley LLC. As the sole managing member of Parsley LLC, we operate and control all of the business and affairs of Parsley LLC and, through Parsley LLC and its subsidiaries, conduct our business. We consolidate the financial and operating results of Parsley LLC and its subsidiaries and record noncontrolling interests for the economic interest in Parsley LLC held by the PE Unit Holders.

Oil and Natural Gas Production Prices and Production Costs

Production and Price History

The following table sets forth information regarding our net production of oil, natural gas and NGLs and certain price and cost information for the periods indicated:

	Year Ended December 31,		
	2018	2017	2016
Revenues (in thousands):			
Oil sales	$ 1,536,244	$ 802,230	$ 387,303
Natural gas sales [1]	51,231	56,571	30,928
Natural gas liquids sales [1]	227,272	103,193	38,273
Total revenues	$ 1,814,747	$ 961,994	$ 456,504
Average realized prices [2]:			
Oil, without realized derivatives (per Bbls)	$ 60.59	$ 48.95	$ 41.34
Oil, with realized derivatives (per Bbls)	58.07	47.68	47.56
Natural gas, without realized derivatives (per Mcf)	1.37	2.43	2.30
Natural gas, with realized derivatives (per Mcf)	1.38	2.40	2.30
Natural gas liquids (per Bbls)	27.21	22.87	16.01
Average price per Boe, without realized derivatives	45.44	38.80	32.60
Average price per Boe, with realized derivatives	43.85	37.94	36.76
Production [1][2]:			
Oil (MBbls)	25,356	16,390	9,368
Natural gas (MMcf)	37,365	23,326	13,463
Natural gas liquids (MBbls)	8,353	4,512	2,390
Total (MBoe)	39,937	24,792	14,002
Average daily production volume:			
Oil (Bbls)	69,468	44,904	25,596
Natural gas (Mcf)	102,370	63,907	36,784
Natural gas liquids (Bbls)	22,885	12,362	6,530
Total (Boe)	109,416	67,923	38,257

(1) Natural gas and NGLs sales and associated production volumes for the year ended December 31, 2018 reflect adjustments associated with our adoption of ASC Topic 606, *Revenue from Contracts with Customers* ("ASC 606"), effective January 1, 2018, as discussed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting the Comparability of Our Financial Condition and Results of Operations—Impact of ASC Topic 606 Adoption."

(2) Average prices shown in the table reflect prices both before and after the effects of our realized commodity hedging transactions. Our calculation of such effects includes both realized gains and losses on cash settlements for commodity derivative transactions and premiums paid or received on options that settled during the period.

Approximately 83%, 88% and 90% of our total estimated proved reserves as of December 31, 2018, 2017 and 2016, respectively, were attributable to the Midland Basin, and approximately 17%, 12% and 10% of our total estimated proved reserves as of December 31, 2018, 2017 and 2016, respectively, were attributable to the Delaware Basin. The following table sets forth information regarding our net production of oil, natural gas and NGLs by basin for the periods indicated:

	Year Ended December 31,								
	2018			2017			2016		
	Midland Basin	Delaware Basin	Total	Midland Basin	Delaware Basin	Total	Midland Basin	Delaware Basin	Total
Production [1]:									
Oil (MBbls)	18,881	6,475	25,356	14,082	2,308	16,390	8,693	675	9,368
Natural gas (MMcf)	31,873	5,492	37,365	20,835	2,491	23,326	13,134	329	13,463
Natural gas liquids (MBbls)	7,243	1,110	8,353	4,087	425	4,512	2,340	50	2,390
Total (MBoe)	31,436	8,501	39,937	21,641	3,151	24,792	13,222	780	14,002

(1) Natural gas and NGLs sales and associated production volumes for the year ended December 31, 2018 reflect adjustments associated with our adoption of ASC 606, effective January 1, 2018, as discussed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting the Comparability of Our Financial Condition and Results of Operations—Impact of ASC Topic 606 Adoption."

Productive Wells

As of December 31, 2018, we had an interest in 571 gross (442.7 net) productive horizontal wells and 1,244 gross (779.7 net) productive vertical wells. Productive wells consist of producing wells and wells mechanically capable of production, including oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have a working interest and net wells are the sum of our fractional working interests owned in gross wells. As of December 31, 2018, we owned an immaterial number of productive wells related to the production of natural gas.

Well Operations

As of December 31, 2018, we operated 453 gross (425.3 net) of our horizontal wells and 919 gross (735.7 net) of our vertical wells. As the operator, we design and manage the development of our wells and supervise operation and maintenance activities on a day-to-day basis. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ petroleum engineers, geologists and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Marketing and Customers

We market the majority of the production from the properties we operate, both for our account and for the accounts of third-party working, royalty and overriding royalty interest owners in these properties. We sell our production at market prices to a relatively small number of purchasers, as is customary in the exploration, development and production business. For the years ended December 31, 2018, 2017 and 2016, the following customers accounted for more than 10% of our revenue:

	Year Ended December 31,		
	2018	2017	2016
Shell Trading (US) Company	53%	62%	44%
Lion Oil, Inc.	22%	3%	—%
Targa Pipeline Mid-Continent, LLC	11%	13%	13%
BML, Inc.	1%	2%	13%

If a major customer decides to stop purchasing oil or natural gas from us, our revenue could decline and our operating results and financial condition could be harmed. However, we believe that the loss of any one or all of our major purchasers would not have a material adverse effect on our financial condition or results of operations, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers. Please see *Note 2—Summary of Significant Accounting Policies—Significant Customers* to our consolidated financial statements included elsewhere in this Annual Report for additional information.

Transportation and Delivery Commitments

During the initial development of our fields, we consider all gathering and delivery infrastructure in the areas of our production. Our oil is transported from the wellhead to our tank batteries by our gathering systems. The purchaser then transports the oil by truck or pipeline to a tank farm, another pipeline or a refinery. Our natural gas is transported from the wellhead to the purchaser's meter and pipeline interconnection point through our gathering systems. In addition, we move the majority of our produced water by pipeline connected to our operated salt water disposal wells rather than by truck. However, due to the inaccessibility of certain of our wells, some produced water will likely always be required to be transported by truck.

We sell oil and natural gas under a variety of contractual agreements, some of which specify the delivery of fixed and determinable quantities. During the year ended December 31, 2018, we entered into the following contracts related to the transportation and/or sale of crude oil:

- An amendment to an existing contract providing firm transportation from one of the pipeline systems through which we transport or sell crude oil. Under this amended contract, we have committed to deliver a minimum average volume of 45,000 Bbls/day from January 1, 2019 to June 30, 2025. If a new third party pipeline system commences operations (the "pipeline commencement date") between January 1, 2019 and June 30, 2020, our commitment will increase to a minimum average volume of 60,000 Bbls/day from the pipeline commencement date through June 30, 2020. If the pipeline commencement date occurs before July 1, 2020, our commitment will increase to a minimum average volume of 75,000 Bbls/day from July 1, 2020 through June 30, 2025, and if the pipeline commencement date occurs between July 1, 2020 and June 30, 2025, our commitment will increase to a minimum average volume of 75,000 Bbls/day from the pipeline commencement date through June 30, 2025. In addition, if the pipeline commencement date occurs after June 30, 2025, we will be required to deliver a minimum average volume of 30,000 Bbls/day for five years following the pipeline commencement date; however, if the pipeline commencement date occurs prior to June 30, 2025, such five-year period will be reduced by the period of time from the pipeline commencement date through June 30, 2025.
- A contract for the transportation and/or sale of crude oil, pursuant to which we have committed to deliver approximately 2.7 MMBbl of oil during the period from September 1, 2018 to December 31, 2019. If we fail to deliver the required volumes, we may elect to extend the performance period by three months.
- A contract for the transportation and/or sale of crude oil that is subject to the commencement of operations of a third-party terminal and pipeline system. Upon the commencement of operations, we will be required to deliver a minimum average volume of 5,000 Bbls/day during the first month, which will increase by 5,000 Bbls/day each month until we are required to deliver a minimum average volume of 35,000 Bbls/day during the seventh month. We will then be required to deliver 35,000 Bbls/day until three years following the commencement of operations of the third-party terminal and pipeline system. At the completion of the initial three year period, our counterparty will have the option to extend the contract for up to four additional years, but if such option is not exercised, we will be have the option to extend the contract for up to two additional years.

We have no fixed delivery commitments other than those described above. We expect to fulfill these delivery commitments for the next one to three years with production from our existing proved developed and proved undeveloped reserves, which we regularly monitor to ensure sufficient availability. In addition, we monitor our current production, our anticipated future production and our future development plans, in each case factoring in production attributable to third-party working, royalty and overriding royalty interest owners, in order to meet our delivery commitments. If production volumes are not sufficient to meet these contractual delivery commitments, we may be subject to deficiency fees unless we purchase commodities in the market to satisfy such commitments.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or to evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons and raising additional capital, which could have a material adverse effect on our business.

There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments of the United States and the jurisdictions in which we operate. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position.

Segment Information and Geographic Area

Operating segments are defined under GAAP as components of an enterprise that engage in activities from which it may earn revenues and incur expenses and for which separate operational financial information is available and regularly evaluated by the chief operating decision maker for the purpose of allocating resources and assessing performance.

Based on our organization and management, we have only one reportable operating segment, which is oil and natural gas exploration and production. Other services that we engage in are ancillary to our oil and natural gas exploration and producing activities and manage these services to support such activities. All of our operations are conducted in one geographic area of the United States. For additional information, see our consolidated financial statements in this Annual Report beginning on page F-1.

Seasonality of Business

Weather conditions affect the demand for and prices of, oil and natural gas. Demand for oil and natural gas is typically higher in the first and fourth quarters, resulting in higher prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

Oil and Natural Gas Leases

Typically the oil and natural gas lease agreements covering our properties provide for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 20% to 25%, resulting in a net revenue interest to us generally ranging from 75% to 80%. Where we own minerals underlying properties that we operate, our net revenue interest will be higher.

Markets for Sale of Production

Our ability to market oil and natural gas found and produced depends on numerous factors beyond our control, the effects of which cannot be accurately predicted or anticipated. Some of these factors include, without limitation, the availability of other domestic and foreign production, the marketing of competitive fuels, the proximity and capacity of pipelines, fluctuations in supply and demand, the availability of a ready market, the effect of United States federal and state regulation of production, refining, transportation and sales and general national and worldwide economic conditions. Additionally, we may experience delays in marketing natural gas production and fluctuations in natural gas prices and our marketing professionals may experience short-term delays in marketing oil due to trucking and refining constraints. There is no assurance that we will be able to market any oil or natural gas produced, or, if such oil or natural gas is marketed, that favorable prices can be obtained.

The United States natural gas market has undergone several significant changes over the past few decades. The majority of federal price ceilings were removed in 1985 and the remainder were lifted by the Natural Gas Wellhead Decontrol Act of 1989. Thus, currently, the price of natural gas in the United States is determined by market forces rather than by regulations. At the same time, the domestic natural gas industry has also seen a dramatic change in the manner in which gas is bought, sold and transported. In most cases, natural gas is no longer sold to pipeline companies. Instead, pipeline companies primarily serve the role of transporter and gas producers are free to sell their product to marketers, local distribution companies, end users or a combination thereof.

In recent years, oil, natural gas and NGLs prices have been under considerable pressure due to oversupply and other market conditions. Specifically, increased foreign production and increased efficiencies in horizontal drilling, combined with the exploration of newly developed shale fields in North America, have dramatically increased global oil and natural gas production, which has led to lower market prices for these commodities. Given the many uncertainties affecting the supply and demand for oil, natural gas and NGLs, we are unable to accurately predict future oil, natural gas and NGLs prices or the overall effect, if any, that the oversupply of such products and other market conditions will have on our financial condition or results of operations.

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by the United States Congress ("Congress"), state governments, the Federal Energy Regulatory Commission (the "FERC") and other federal and state regulatory agencies and federal, state and local courts. We cannot predict when or whether any such proposals may become effective. We do not believe that such action or proposal would have a material disproportionate effect on us as compared to similarly situated competitors.

Regulation Affecting Production

As described above, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. In addition, all of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area and the unitization or pooling of crude oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. These laws and regulations may limit the number of oil and natural gas wells we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs 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 be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells or limit the number of locations we can drill.

The failure to comply with the rules and regulations of oil and natural gas production and related operations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation Affecting Sales and Transportation of Commodities

Sales prices for oil, natural gas and NGLs are not currently regulated and therefore are dictated by the prevailing market prices. Although prices of these energy commodities are currently unregulated, Congress historically has been active in their regulation. We cannot predict whether new legislation to regulate oil and natural gas, or the prices charged for these commodities, might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, the proposals might have on our operations. Sales of oil and natural gas may be subject to certain state and federal reporting requirements.

The price and terms of service of transportation of the commodities, including access to pipeline transportation capacity, are subject to extensive federal and state regulation. Such regulation may affect the marketing of oil and natural gas produced, as well as the revenues received for sales of such production. Gathering systems may be subject to state ratable take statutes and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, oil and natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase, or accept for gathering, without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes may affect whether and to what extent gathering capacity is available for oil and natural gas production, if any, of the drilling program and the cost of such capacity. Further, state laws and regulations govern rates and terms of access to intrastate pipeline systems, which may similarly affect market access and cost.

The FERC regulates interstate natural gas pipeline transportation rates and service conditions. The FERC regularly proposes and implements new rules and regulations affecting interstate transportation. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and to promote market transparency. We do not believe that such FERC action would have a material disproportionate effect on our drilling program as compared to other similarly situated natural gas producers.

Gathering services, which occur upstream of FERC jurisdictional transmission services, and which are performed onshore and in state-controlled waters are regulated by state governments. Although the FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, the FERC's determinations as to the classification of facilities is conducted on a case-by-case basis. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

In addition to the regulation of natural gas pipeline transportation, the FERC has jurisdiction over the purchase or sale of gas or the purchase or sale of transportation services subject to the FERC's jurisdiction pursuant to the Energy Policy Act of 2005. Under this law, it is unlawful for "any entity," including a producer such as us, that is otherwise not subject to the FERC's jurisdiction under the Natural Gas Act of 1938 to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of gas, or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. The FERC's rules implementing this provision make it unlawful, in connection with the purchase or sale of gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud, to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading, or to engage in any act or practice that operates as a fraud or deceit upon any person. The Energy Policy Act of 2005 also gives the FERC authority to impose civil penalties for violations of the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 up to $1,269,500 per day per violation (adjusted annually based on inflation) and disgorge profits associated with any violation. The anti-manipulation rule applies to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which includes the annual reporting requirements under Order 704 (defined below).

In December 2007, the FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order 704"). Under Order 704, any market participant, including a producer such as us, that engages in wholesale sales or purchases of gas that equal or exceed 2.2 million MMBtus of physical natural gas in the previous calendar year, must annually report such sales and purchases to the FERC on Form No. 552 on May 1 of each year. Form No. 552 contains aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize or contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 is intended to increase the transparency of the wholesale gas markets and to assist the FERC in monitoring those markets and in detecting market manipulation.

The FERC also regulates rates and service conditions for the interstate transportation of liquids, including oil and NGLs, under the Interstate Commerce Act (the "ICA"). Prices received from the sale of liquids may be affected by the cost of transporting those products to market. 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 on July 1, 2016, the FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 1.23%. This adjustment is subject to review every five years. Under the FERC's regulations, a liquids pipeline can request the authority to charge market-based rates for transportation service if it satisfies certain criteria, and also 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.

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. Therefore, requests for service by new shippers or increased volume by existing shippers may reduce the capacity available to us. Any prolonged interruption in the operation or curtailment of available capacity of the pipelines that we rely upon for liquids transportation could have a material adverse effect on our business, financial condition, results of operations and cash flows. However, we believe that access to liquids pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Intrastate liquids pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate liquids pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate liquids pipeline rates, varies from state to state. We believe that the regulation of liquids pipeline transportation rates will not affect our operations in any way that is materially different from the effects on our similarly situated competitors.

In addition to the FERC's regulations, we are required to observe anti-market manipulation laws with regard to our physical sales of energy commodities. 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 $1,180,566 per violation per day (adjusted annually based on inflation). In July 2010, Congress passed the Dodd-Frank Act, which incorporated an expansion of the authority of the Commodity Futures Trading Commission (the "CFTC") to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to crude oil swaps and futures contracts, is similar to the anti-manipulation authority granted to the FTC with respect to crude oil purchases and sales. In July 2011, the CFTC issued final rules to implement its new anti-manipulation authority. The rules subject violators to a civil penalty of up to the greater of $1,191,842 (adjusted annually based on inflation) or triple the monetary gain to the person for each violation.

Regulation of Environmental and Occupational Safety and Health Matters

Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment and occupational health and safety. These laws and regulations may, among other things: (i) require the acquisition of permits to conduct exploration, drilling and production operations; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; and (v) impose substantial liabilities for pollution resulting from drilling and production operations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations and the issuance of orders enjoining performance of some or all of our operations.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The clear trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment and thus any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage, transportation, disposal, or remediation requirements could have a material adverse effect on our financial position and results of operations. We may be unable to pass on such increased compliance costs to our purchasers. Moreover, accidental releases or spills may occur in the course of our operations and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. While compliance with existing environmental laws and regulations has not had a material adverse effect on our operations to date, we can provide no assurance that this will continue in the future.

The following is a summary of the more significant existing and proposed environmental, occupational health and safety laws and regulations to which our business operations are or may be subject to and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

The Resource Conservation and Recovery Act

The 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. Pursuant to rules issued by the U.S. Environmental Protection Agency (the "EPA"), individual state governments administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of crude oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address the EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and natural gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires the EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and natural gas wastes or to sign a determination that revision of the regulations is not necessary. EPA action in response to the consent decree remains pending. Removal of RCRA's exemption for exploration and production wastes has the potential to significantly increase our waste disposal costs to manage, which in turn will result in increased operating costs and could adversely impact our results of operations and financial position. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, imposes 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 the current and former owners and operators of the site where the release occurred and 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. In addition, 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.

We generate materials in the course of our operations that may be regulated as hazardous substances. Despite the "petroleum exclusion" of CERCLA, which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. In addition, we currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration, production and processing for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state and local laws. Under such laws, we could be required to undertake investigatory, response, or corrective measures, which could include soil and groundwater sampling, the removal of previously disposed substances and wastes, the cleanup of contaminated property, or remedial plugging or pit closure operations to prevent future contamination, the costs of which could be substantial.

Water Discharges

The Federal Water Pollution Control Act, or 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 other substances, into waters of the United States. The discharge of pollutants into regulated waters, including wetland areas, is prohibited, except in accordance with the terms of a permit issued by the EPA, the U.S. Army Corps of Engineers (the "USACE") or an analogous state agency. In September 2015, the EPA and the USACE issued a final rule redefining the scope of the EPA's and the USACE's jurisdiction under the CWA with respect to certain types of waterbodies and classifying these waterbodies as regulated wetlands (the "WOTUS" rule). Several legal challenges to the rule followed, along with attempts to stay implementation of the WOTUS rule following the change in U.S. presidential administrations. Currently, the WOTUS rule is active in 22 states and enjoined in 28 states. However, in December 2018, the EPA and the USACE proposed changes to regulations under the CWA that would provide discrete categories of jurisdictional waters and tests for determining whether a particular waterbody meets any of those classifications. Several groups have already announced their intent to challenge the proposed WOTUS replacement rule. Therefore, the scope of jurisdiction under the CWA is uncertain at this time. To the extent the original WOTUS rule or any replacement rule expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. In addition, federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations. We do not expect the costs to comply with the requirements of the CWA to have a material adverse effect on our operations.

The Oil Pollution Act of 1990 amends the CWA and establishes strict liability for owners and operators of facilities that cause a release of oil into waters of the United States. In addition, this law requires owners and operators of facilities that store oil above specified threshold amounts to develop and implement spill prevention, control and countermeasures plans.

Safe Drinking Water Act and Saltwater Disposal Wells

In the course of our operations, we produce water in addition to oil and natural gas. Water that is not recycled or otherwise disposed of on the lease may be sent to saltwater disposal wells for injection into subsurface formations. Underground injection operations are regulated under the federal Safe Drinking Water Act and permitting and enforcement authority may be delegated to state governments. In Texas, the Texas Railroad Commission ("RRC") regulates the disposal of produced water by injection well. The RRC requires operators to obtain a permit from the agency for the operation of saltwater disposal wells and establishes minimum standards for injection well operations. In response to recent seismic events near underground injection wells used for the disposal of oil and natural gas-related waste waters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or placed volumetric injection limits on existing wells or imposed moratoria on the use of such injection wells. In response to concerns related to induced seismicity, regulators in some states have already adopted or are considering additional requirements related to seismic safety. For example, the RRC has adopted rules for injection wells to address these seismic activity concerns in Texas. Among other things, the 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 RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. More stringent regulation of injection wells could lead to reduced construction or the capacity of such wells, which could in turn impact the availability of injection wells for disposal of wastewater from our operations. Increased costs associated with the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal, may reduce our profitability. The costs associated with the disposal of proposed water are commonly incurred by all oil and natural gas producers, however, and we do not believe that these costs will have a material adverse effect on our operations.

Air Emissions

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as tank batteries and compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard for ozone from 75 to 70 parts per billion. The EPA approved final attainment/nonattainment designations with the new ozone standards in July 2018 and currently all of the areas in which we operate are in attainment with such standards. However, state implementation of these revised air quality standards or a change in the attainment status of the areas in which we operate could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant. Separately, in June 2016, the EPA finalized a rule regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements, which in turn could result in operational delays or require us to install costly pollution control equipment. The EPA has also adopted new rules under the Clean Air Act that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors and from pneumatic controllers and storage vessels. The EPA expanded on its emission standards for volatile organic compounds in June 2016 with the issuance of first-time standards, known as Subpart OOOOa, to address emissions of methane from equipment and processes across the oil and natural gas source category, including hydraulically fractured oil and natural gas well completions. Following the change in presidential administration, there have been attempts to modify these regulations, and litigation concerning the regulations is ongoing. As a result of these developments, substantial uncertainty exists with respect to implementation of the EPA's 2016 methane rule. However, given the long-term trend toward increasing regulation, future federal methane regulation of the oil and gas industry remains a possibility, and several states have separately imposed their own regulations on methane emissions from oil and gas production activities. These and other air pollution control and permitting requirements have the potential to delay the development of oil and natural gas projects and increase our costs of development and production, which costs could be significant. We do not believe that compliance with such requirements, however, will have a material adverse effect on our operations.

Regulation of Greenhouse Gas Emissions

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") endanger public health and the environment, the EPA has adopted regulations under existing provisions of the Clean Air Act that, among other things, establish Prevention of Significant Deterioration ("PSD"), construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards for these emissions. EPA rulemakings related to GHG emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the annual reporting of GHG emissions from certain petroleum and natural gas system sources in the U.S., including, among others, onshore and offshore production facilities, which include certain of our operations. Also, as noted above, the EPA has promulgated a New Source Performance Standard related to methane emissions from the oil and natural gas source category.

While Congress has considered legislation related to the reduction of GHG emissions in the past, no significant legislation to reduce GHG emissions has been adopted at the federal level. In the absence of Congressional action, a number of state and regional GHG restrictions have emerged. At the international level, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The Paris Agreement entered into force in November 2016. Although this agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges from participating nations to voluntarily limit or reduce future emissions. In June 2017, President Trump stated that the United States would withdraw from the Paris Agreement, but may enter into a future international agreement related to GHGs. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process is uncertain, and the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations.

Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce and lower the value of our reserves. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Finally, it should also be noted that many scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other climatic events; if any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, resulting in new legislative and regulatory initiatives that seek to increase the regulatory burden imposed on hydraulic fracturing.

At the federal level, the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities. Further, the EPA finalized regulations under the CWA in June 2016 that prohibit wastewater discharges from hydraulic fracturing and certain other natural gas operations to publicly owned wastewater treatment plants. Also, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain limited circumstances.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of, or prohibiting, drilling or hydraulic fracturing activities. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we may be required to incur significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities and perhaps even be precluded from drilling wells.

If new federal, state or local laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities and make it more difficult or costly to perform fracturing. Any such regulations limiting or prohibiting hydraulic fracturing could reduce oil and natural gas exploration and production activities and, therefore, adversely affect our business. Such laws or regulations could also materially increase our costs of compliance and doing business by more strictly regulating how hydraulic fracturing wastes are handled or disposed.

Endangered Species Act and Migratory Birds

The federal Endangered Species Act ("ESA") and (in some cases) comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. We may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species, such as the sage grouse, that potentially could be listed as threatened or endangered under the ESA may exist. The U.S. Fish and Wildlife Service (the "FWS") may designate critical habitat and suitable habitat areas that it believes are necessary for the survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. Moreover, as a result of a 2011 settlement agreement, the FWS was required to make a determination on listing of more than 250 species as endangered or threatened under the FSA by no later than completion of the agency's 2017 fiscal year. The FWS missed the deadline but reportedly continues to review new species for protected status under the ESA pursuant to the settlement agreement. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Recently, there have been renewed calls to review protections currently in place for the dunes sagebrush lizard, whose habitat includes portions of the Permian Basin, and to reconsider listing the species under the ESA. The designation as threatened or endangered of previously unprotected species in areas where we operate could cause us to incur increased costs arising from species protection measures or could result in limitations on our development and production activities that could have a material adverse impact on our ability to develop and produce our reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

OSHA

We are subject to the requirements of the Occupational Safety and Health Administration ("OSHA") and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act and comparable state statutes and any implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens.

Related Permits and Authorizations

Many environmental laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation, or other oil and natural gas activities and to maintain these permits and compliance with their requirements for on-going operations. These permits are generally subject to protest, appeal, or litigation, which, in certain cases, can delay or halt projects and cease production or operation of wells, pipelines and other operations.

Related Insurance

We maintain insurance against some risks associated with above or underground contamination that may occur as a result of our exploration and production activities. However, this insurance is limited to activities at the well site, and there can be no assurance that this insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by us. The occurrence of a significant event that is not fully insured or indemnified against could have a material adverse effect on our financial condition and operations.

Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2018, nor do we anticipate that such expenditures will be material in 2019.

Employees

As of December 31, 2018, we employed 527 people. We consider our relations with employees to be satisfactory. Our future success will depend in part on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We regularly utilize the services of independent contractors to perform various field and other services.

Available Information

We file or furnish annual, quarterly and current reports, proxy and information statements and other documents with the SEC under the Exchange Act. The SEC maintains an internet website at *www.sec.gov* that contains these reports, proxy and information statements and other information regarding issuers, including us, that file electronically with the SEC.

Our Class A common stock is listed and traded on the New York Stock Exchange (“NYSE”) under the symbol “PE.” Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the offices of the NYSE, at 20 Broad Street, New York, New York 10005.

We also make available free of charge through our website, *www.parsleyenergy.com*, electronic copies of certain documents that we file with the SEC, including our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

ITEM 1A. RISK FACTORS

You should carefully consider the following risks and all of the information contained in this Annual Report. Our business, financial condition and results of operations could be materially and adversely affected by any of these risks. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we consider immaterial also may adversely affect us.

Risks Related to the Oil and Natural Gas Industry and Our Business

Oil, natural gas and NGLs prices are volatile. A sustained period of low commodity prices or decreased demand for hydrocarbons may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

Our revenue, profitability, cash flow, access to capital, future rate of growth and the carrying value of our oil and natural gas properties are heavily influenced by the prices we receive for our oil and natural gas production and the prevailing market prices from time to time for oil, natural gas and NGLs. Historically, oil, natural gas and NGLs prices have been volatile and subject to wide fluctuations in response to domestic and international changes in supply and demand, economic and legal forces, events and uncertainties, and numerous other factors beyond our control, including those factors listed below (which list is not exhaustive):

- worldwide and regional economic conditions impacting the global supply and demand for oil, natural gas and NGLs;
- the level of global exploration and production;
- the level of global oil, natural gas and NGLs inventories;
- the price and quantity of oil, natural gas and NGLs imports to and exports from the U.S.;
- political or economic conditions in or affecting other producing countries and regions, including conflicts or instability in the Middle East, Africa, South America and Eastern Europe;
- actions of the Organization of the Petroleum Exporting Countries, its members and other state-controlled companies relating to oil price and production controls;
- prevailing prices on local price indices in the areas in which we operate and expectations about future commodity prices;
- the proximity, capacity, cost and availability of gathering, transportation, processing, fractionation, refining and export facilities;
- localized and global supply and demand fundamentals and transportation availability;
- weather conditions;
- technological advances affecting fuel economy, energy supply and energy consumption;
- shareholder activism or activities by non-governmental organizations to restrict the exploration and production of oil and natural gas so as to minimize emissions of carbon dioxide and methane GHGs;
- the price and availability of alternative fuels and energy sources;
- the effect of energy conservation measures, alternative fuel requirements and increasing demand for alternatives to oil and natural gas;
- the impact of currency fluctuations; and
- domestic, local and foreign governmental regulations, including environmental regulations and taxes.

These factors and the volatility of the energy markets, which we expect will continue, make it extremely difficult to predict future oil, natural gas and NGLs price movements with any certainty. The price of oil, natural gas and NGLs decreased significantly in the latter half of 2018 and, as of December 31, 2018, NYMEX WTI oil futures contract prices and NYMEX Henry Hub gas futures prices were $45.41 per barrel and $2.94 per MMBtu, respectively.

A further or extended decline in commodity prices could materially and adversely affect the amount of oil, gas and NGLs that we can produce economically. This may result in our having to make significant downward adjustments to our estimated proved reserves. A reduction in production could also result in a shortfall in expected cash flows and require us to reduce capital spending or borrow funds to cover any such shortfall. Any of these factors could negatively affect our ability to replace our production and future rate of growth. In addition, under such conditions, we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in the present value of our reserves and our ability to develop future reserves. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

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

We have acquired significant amounts of unproved property in order to further our development efforts and expect to continue to undertake similar acquisitions in the future. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and improve our results of operations over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. Additionally, we cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that wells drilled by us in prospects that we pursue will be productive, that we will recover all or any portion of our investment in such unproved property or wells, or that production from wells drilled by us will achieve our desired cash flow and rate of return for all or any portion of our properties.

Development and exploratory drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient commercial quantities to cover the drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, equipment failures or accidents, shortages of equipment or personnel, environmental issues and for other reasons. In addition, wells that are profitable may not meet our internal or disclosed return targets, which are dependent upon the current and expected future market prices for oil and natural gas, expected costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost.

Properties we acquire may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with each of these assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline and we cannot necessarily observe structural and environmental problems during our inspection. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations. If properties we acquire do not produce as projected or have liabilities we were unable to identify, we could experience a decline in our reserves and production, which could adversely affect our business, financial condition and results of operations.

Our acquisition and development projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the acquisition and development of oil and natural gas reserves. During the year ended December 31, 2018, we incurred approximately $1.9 billion for acquisition, exploration and development activities (excluding asset retirement obligations). Our 2019 budget for capital development expenditures is approximately $1,350.0 million to $1,550.0 million, which excludes any amounts that may be paid for acquisitions. Approximately 85% of this budget estimate is expected to be used for drilling and completions and approximately 15% of this budget estimate is expected to be used for infrastructure and other expenditures. The amount and timing of 2019 capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned 2019 capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Requirements and Sources of Liquidity."

We may finance our future capital expenditures with cash on hand, cash flow from operations, borrowings under our Revolving Credit Agreement and proceeds received from any divestiture of our oil and gas properties. As of December 31, 2018, we had approximately $1,154.5 million of liquidity, with $163.2 million of cash and cash equivalents. The borrowing base under our Revolving Credit Agreement currently stands at $2.3 billion, with a commitment level of $1.0 billion. There were no borrowings outstanding and $8.7 million in letters of credit outstanding as of December 31, 2018, resulting in availability of $991.3 million.

Our cash flow from operations and access to capital, however, are subject to a number of variables beyond our control, including:

- the volume of oil, natural gas and NGLs we are able to produce from existing wells;
- the ratio of oil to natural gas and NGLs we are able to produce from existing wells;
- the prices at which our production is sold;
- our proved reserves;
- our ability to acquire, locate and produce new reserves;
- our ability to borrow under our Revolving Credit Agreement;

- the global credit and securities markets; and
- the ability and willingness of lenders and investors to provide capital and the cost of such capital.

If our revenues, liquidity or the borrowing base under our Revolving Credit Agreement decrease as a result of lower oil, natural gas and NGLs prices, operating difficulties, declines in reserves or for any other reason, and we require additional capital for our capital expenditure needs, we may have limited ability to obtain the capital necessary to sustain our operations and growth at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash on hand, cash flow from operations and borrowings under our Revolving Credit Agreement are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in the curtailment of our operations relating to development of our properties or the curtailment of acquisitions that may be favorable to us, which in each case could lead to a decline in our reserves and production, and could adversely affect our business, financial condition and results of operations.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, we will likely be required to take write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our proved and unproved properties for possible impairment. Based on commodity prices and other specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A write-down constitutes a non-cash charge to earnings. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Impairment of Oil and Gas Properties” and *Note 14—Disclosures About the Fair Value of Financial Instruments* to our consolidated financial statements included elsewhere in this Annual Report for specific information regarding our impairments. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our acquisition and development activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and natural gas production.

Our decisions to acquire and develop properties depend in part on the evaluation of data obtained through geophysical and geological analysis, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see “—Our reserves estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserves estimates or underlying assumptions will materially affect the quantities and present value of our reserves.” In addition, the costs involved in drilling, completing and operating our wells are often uncertain before we commence drilling.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with regulatory requirements, including limitations on wastewater disposal, discharge of GHGs, hydraulic fracturing and other potential environmental impacts from our operations, including protections for threatened or endangered plant and animal life;
- abnormal pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures, accidents or other unexpected operational events;
- lack of available gathering facilities or delays in the construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- adverse or severe weather conditions or events, including any such conditions or events that may be related to climate change;
- issues related to compliance with environmental regulations;

- environmental hazards, such as oil and natural gas leaks, oil spills, pipeline and tank ruptures, the presence of naturally occurring radioactive materials and the unauthorized discharge of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in oil, natural gas and NGLs prices;
- limited availability of financing at acceptable terms;
- loss of title or other title-related issues and disputes; and
- limitations in the market for oil, natural gas and NGLs.

Our 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 their drilling.

Our management team has identified certain drilling locations and prospects on our existing acreage as part of our anticipated future drilling plans. These drilling locations and prospects represent a significant part of our future drilling plans. Our ability to drill and develop these locations depends on a number of factors, including the availability and cost of capital, negotiation of agreements with third parties, commodity prices, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and the availability of water sourcing and distribution systems, regulatory permits and approvals and other factors. In addition, we may alter the spacing between our anticipated drilling locations, which could impact the number of our drilling locations, the number of wells that we drill, and the volumes of oil and gas we ultimately recover. Because of these uncertainties, there can be no assurance that our identified potential well locations will ever be drilled or, if drilled, we will be able to produce oil or natural gas from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acreage on which our potential drilling locations have been identified, certain of the leases for such acreage may expire. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business and results from operations.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under the applicable debt instruments, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our Revolving Credit Agreement and our senior unsecured notes, will depend on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control and can vary significantly from year to year. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay planned investments and capital expenditures, or to sell assets, seek additional financing in the debt or equity markets or restructure or refinance our indebtedness. Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments may restrict us from pursuing some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a decline in our credit ratings, which could harm our ability to incur additional indebtedness.

In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and may be required to divest of material assets or operations to meet our debt service and other obligations. Our Revolving Credit Agreement and the indentures governing our senior unsecured notes restrict our ability to divest of assets and our use of the proceeds from such divestitures. We may not be able to consummate those divestitures or, if consummated, the proceeds from such divestitures may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not allow us to meet our debt service obligations.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

Our Revolving Credit Agreement and the indentures governing our senior unsecured notes contain a number of significant restrictive covenants, including covenants that may limit our ability to, among other things:

- incur or guarantee additional indebtedness or issue certain types of preferred stock;
- pay dividends on capital stock or redeem, repurchase, or retire our capital stock or subordinated indebtedness;

- transfer or sell assets;
- make certain investments;
- create certain liens;
- enter into agreements that restrict dividends or payments from our restricted subsidiaries to us;
- consolidate, merge, or transfer all or substantially all of our assets;
- engage in transactions with affiliates; and
- form unrestricted subsidiaries.

In addition, our Revolving Credit Agreement requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. These restrictions may also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our Revolving Credit Agreement and the indentures governing our senior unsecured notes impose on us.

Our Revolving Credit Agreement also limits the amount we can borrow up to the lowest of (i) the borrowing base (which currently stands at $2.3 billion), (ii) the aggregate elected borrowing base commitments (which currently stands at $1.0 billion) and (iii) $2.5 billion. The borrowing basis is subject to scheduled annual and other elective borrowing base redeterminations based upon the projected revenues from the oil and natural gas properties securing our loan. As a result of any redetermination, the lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our Revolving Credit Agreement. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. If the requisite number of lenders do not agree to a proposed borrowing base, then the borrowing base will be the highest borrowing base acceptable to such lenders. Outstanding borrowings in excess of the borrowing base must be repaid.

If we are unable to comply with the restrictions and covenants in the agreements governing our indebtedness, there could be an event of default under the terms of these agreements, which could result in an acceleration of payment of funds that we have borrowed.

If we are unable to comply with the various restrictions and covenants in the agreements governing our indebtedness, including our Revolving Credit Agreement and the indentures governing our senior unsecured notes, there could be an event of default under the terms of these agreements. Our ability to comply with these restrictions and covenants, including meeting certain financial ratios and tests, may be affected by events beyond our control. If market or other economic conditions deteriorate or if oil, natural gas and NGLs prices decline, our ability to comply with these covenants may be impaired. We cannot assure you that we will be able to comply with these restrictions and covenants or meet such financial ratios and tests.

In the event of a default under the agreements governing our indebtedness, the lenders under our Revolving Credit Agreement could terminate their commitments to lend and the holders of any of our indebtedness could elect to accelerate and declare all amounts borrowed to be immediately due and payable. A default under our Revolving Credit Agreement could cause a cross-default under the indentures governing our senior unsecured notes, any other indebtedness outstanding and the ISDA Agreements we have entered into as of such default. See “Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk” for more information about our ISDA Agreements.

If any of these events occur, our assets might not be sufficient to repay in full all of our outstanding indebtedness and we may be unable to find alternative financing. Even if we could obtain alternative financing, it might not be on terms that are favorable or acceptable to us. Additionally, we may not be able to amend the agreements governing our indebtedness or obtain needed waivers on satisfactory terms.

Commodity hedging transactions may limit our potential gains or fail to protect us from declines in commodity prices.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of the commodities we sell, we enter into commodity derivative contracts for a significant portion of our production, with an emphasis on oil production, primarily consisting of put spreads, basis swaps and three-way collars. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Overview—Realized Prices on the Sale of Oil, Natural Gas and NGLs.” While intended to reduce the effects of crude oil and natural gas price volatility, such transactions may limit our potential gains if prices rise over the price established by such arrangements. Conversely, our hedging program may be inadequate to protect us from continuing and prolonged declines in the price of crude oil or natural gas.

Global commodity prices are volatile. Such volatility challenges our ability to forecast and, as a result, it may become more difficult to manage our hedging program. In trying to manage our exposure to commodity price risk, we may end up hedging too much or too little, depending upon how our crude oil or natural gas volumes and our production mix fluctuate in the future. Hedging transactions may also expose us to the risk of financial loss in certain circumstances, including instances in which: our production is less than expected; there is an increase in the differential between the underlying price in the derivative instrument and the actual prices received; the counterparties to our futures contracts fail to perform under the contracts; or a sudden unexpected event materially impacts crude oil or natural gas prices. In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for oil, natural gas and NGLs, which could also have an adverse effect on our financial condition.

Our derivative transactions expose us to counterparty credit risk.

Our commodity derivative contracts expose us to risk of financial loss if a counterparty fails to perform under a contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the contract, and we may not be able to realize the benefit of the contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our 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, our derivative contract receivable positions generally increase, which increases our counterparty credit exposure. If any of our counterparties were to default on their obligations under a derivative contract, such a default could have a material adverse effect on our results of operations, and could result in a larger percentage of our future production being subject to commodity price changes and could increase the likelihood that our derivative contracts may not achieve their intended strategic purpose.

Our reserves estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserves estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. Oil and gas reserve engineering is not an exact science; it relies on subjective interpretations of data that may be inaccurate or incomplete and requires predictions and assumptions of future reservoir behavior and economic conditions. Estimates of economically recoverable oil and gas reserves and of future net cash flow depend upon a number of variable factors and assumptions, including:

- the assumed accuracy of field measurements and other reservoir data, including type curve forecast models;
- assumptions regarding expected reservoir performance relative to historical analog reservoir performance;
- the quality and quantity of available data and the interpretation of that data;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning the availability of capital and its costs;
- assumptions concerning future commodity prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserves estimates are necessarily subjective, each of the following items may differ materially from those assumed in estimating reserves:

- the quantities of oil and gas that we ultimately recover;
- the ratio of oil to gas of the hydrocarbons that we ultimately recover;
- the timing of the recovery of oil and gas reserves;
- the production and operating costs incurred to recover the reserves;
- the amount and timing of future development expenditures; and
- future commodity prices.

In addition, if these assumptions prove to be incorrect, our estimates of reserves, the economically recoverable quantities of oil and gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and our estimates of future net cash flows from our reserves could change significantly. Over time, we may make material changes to reserves estimates taking into account changes in our assumptions and the results of our development activities and actual drilling, testing and production.

The Standardized Measure of our estimated proved reserves and our PV-10 are not necessarily the same as the current market value of our estimated proved reserves.

The present value of future net cash flow from our proved reserves ("Standardized Measure"), and our related PV-10 calculation, may not represent the current market value of our estimated proved reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flow from our estimated proved reserves on 12-month average index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect as of the date of the estimate, holding the prices and costs constant through the life of the properties.

Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than current estimates. In addition, the 10% 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 us or the oil and natural gas industry in general. Therefore, the estimates of Standardized Measure in this Annual Report should not be construed as accurate estimates of the current market value of our proved reserves.

Approximately 24% of our net leasehold acreage is undeveloped and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our future oil and natural gas reserves and production and, therefore, our future cash flow and income.

As of December 31, 2018, approximately 24% of our net leasehold acreage was undeveloped or acreage on which wells have not been completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. Unless production is established within a defined period of time on the undeveloped acreage covered by our leases, such leases will expire. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage. Further, to the extent we determine that it is not economic to develop particular undeveloped acreage, we may intentionally allow leases to expire. The cost to renew such leases may increase significantly and we may not be able to renew such leases on commercially reasonable terms or at all. In addition, on certain portions of our acreage, third-party leases become immediately effective if our leases expire. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business. Failing to develop our undeveloped leasehold acreage or allowing leases to expire could result in leasehold abandonment, impairment, charges or a reduction in our oil and natural gas reserves and production, any of which in turn could have a material adverse effect on our financial results. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Impairment of Oil and Gas Properties" and *Note 14—Disclosures About the Fair Value of Financial Instruments* to our consolidated financial statements included elsewhere in this Annual Report for specific information regarding our leasehold abandonments and impairments. For the year ended December 31, 2018, as a result of periodic assessments of our unproved properties that are not held-by-production, we recorded non-cash leasehold abandonment and impairment charges of $127.0 million relating to acreage expiring in future periods because we have no current plans to drill or extend the leases prior to their expiration. For the years ended December 31, 2018, 2017 and 2016, we recognized non-cash leasehold abandonment and impairment expense of $33.8 million, $32.9 million and $6.1 million, respectively, due to leases expiring during those periods.

Our producing properties are located in the Permian Basin of west Texas, making us vulnerable to risks associated with operating in a single geographic area.

All of our producing properties are geographically concentrated in the Permian Basin of west Texas. At December 31, 2018, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, severe weather events, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or NGLs.

The marketability of our production is dependent upon vehicles, transportation facilities and other facilities, most of which we do not control. If these vehicles or facilities are unavailable, or if we are unable to access such vehicles or facilities on commercially reasonable terms, our operations could be interrupted and our revenues reduced.

The marketing of oil, natural gas and NGLs production depends in large part on the availability, proximity and capacity of trucks, pipelines and storage facilities, gas gathering systems and other transportation, processing and refining facilities, as well as the existence of adequate markets. If there is insufficient capacity available on these systems, if these systems are unavailable to us, or if these systems are unavailable to us on commercially reasonable terms, the price offered for our production could be significantly depressed, or we could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons while we construct or purchase our own facility or system. We also rely (and expect to rely in the future) on facilities developed and owned by third parties in order to store, process, transport and sell our oil, natural gas and NGLs production. Our plans to develop and sell our oil and natural gas reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient transportation, storage or processing facilities to us, especially in areas of planned expansion where such facilities do not currently exist, on commercially reasonable terms or otherwise.

The volume of oil and natural gas that we can produce is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering, transportation, processing, fractionation, refining or export facilities we utilize, or lack of capacity on such facilities. The curtailments arising from these and similar circumstances may last from a few days to several months and, in many cases, we may be provided only limited, if any, advance notice as to when these circumstances will arise and their duration. Any such shut in or curtailment, or any inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, would adversely affect our financial condition and results of operations.

Our ability to produce crude oil, natural gas and NGLs economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of or recycle the water we use economically and in an environmentally safe manner.

Drilling and development activities require the use of water and result in the production of waste water. For example, the hydraulic fracturing process, which we employ to produce commercial quantities of crude oil, natural gas and NGLs, requires the use and disposal of significant quantities of water. Limitations or restrictions on our ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought) could materially and adversely impact our operations. Severe drought conditions can result in local water districts taking steps to restrict the use of water in their jurisdictions for drilling and hydraulic fracturing in order to protect local water supply. If we are unable to obtain water to use in our operations from local sources, it may need to be obtained from non-local sources and transported to drilling sites, resulting in increased costs, or we may be unable to economically drill for or produce oil and natural gas, each of which could have an adverse effect on our financial condition, results of operations and cash flows.

In addition, we must dispose of the fluids produced from oil and gas production operations, including produced water, directly or through the use of third party vendors. Some studies have linked earthquakes or induced seismicity in certain areas to underground injection of produced water resulting from oil and gas activities, which has led to increased public and governmental scrutiny of injection safety. In response to concerns regarding induced seismicity, regulators in Texas have adopted new 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. 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.

Another consequence of water disposal activities and 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 our use of injection wells or commercial disposal wells to dispose of produced water. Increased regulation and attention given to water disposal and 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 limitations on disposal well volumes, disposal rates and pressures or locations, require us or our vendors to shut down or curtail the injection into disposal wells, or cause delays, interruptions or termination of our operations, which events could have a material adverse effect on our business, financial condition and results of operations.

A negative shift in investor sentiment towards the oil and gas industry could adversely affect our ability to raise equity and debt capital.

Certain segments of the investor community have recently developed negative sentiment towards investing in our industry. Recent equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. Some investors, including certain pension funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the oil and gas sector based on social and environment considerations. Certain other stakeholders have pressured commercial and investment banks to stop funding oil and gas projects. Such developments could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also result in a reduction of available capital funding for potential development projects, further impacting our future financial results.

Prolonged decreases in production due to decreased developmental activities, production related difficulties or otherwise may require us to pay certain non-use fees or impact our ability to comply with certain contractual requirements.

Due to the nature of our drilling programs and the oil and natural gas industry in general, we are party to certain agreements that require us to meet various contractual obligations or require us to utilize a certain amount of goods or services, including, but not limited to, throughput volume commitments and drilling commitments. In the event of decreased development activities or production-related difficulties, we could be required to pay for unutilized goods or services or we may be unable to meet these contractual obligations. For additional information, see *Note 13—Commitments and Contingencies* to our consolidated financial statements included elsewhere in this Annual Report.

We may incur losses as a result of title defects in the properties in which we invest.

It is generally our practice in acquiring oil and natural gas leases or interests not to incur the expense of retaining lawyers to examine the title to the leases and underlying mineral interest at the time of acquisition. Rather, we rely upon the judgment of lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property. In addition, to the extent title opinions or other investigations prior to the commencement of drilling operations reflect title defects affecting such properties, we are typically responsible for curing any such defects at our expense. The discovery of any such title defects could also delay or prohibit the commencement of drilling operations on the affected properties.

The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not ultimately be developed or produced.

At December 31, 2018, 40% of our total estimated proved reserves were classified as proved undeveloped. Our 210,404 MBoe of estimated proved undeveloped reserves will require an estimated $2.4 billion of development capital over the next five years. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. The future development of our proved undeveloped reserves is dependent on future commodity prices, costs and economic assumptions that align with our internal forecast as well as access to liquidity sources, such as cash flow from operations, capital markets and our Revolving Credit Agreement. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

SEC rules could limit our ability to book additional proved undeveloped reserves in the future.

SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they are related to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit our ability to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill those wells within the required five-year timeframe.

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

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

We depend upon several significant purchasers for the sale of most of our oil and natural gas production. The loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil and natural gas we produce.

The availability of a ready market for any oil and/or natural gas we produce depends on numerous factors beyond the control of our management, including, but not limited to, the extent of domestic production and imports of oil, the proximity and capacity of pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of oil and natural gas sold in interstate commerce. In addition, we depend upon several significant purchasers for the sale of most of our oil and natural gas production. See "Item 1. Business—Oil and Natural Gas Production Prices and Production Costs—Marketing and Customers." We cannot assure you that we will continue to have ready access to suitable markets for our future oil and natural gas production. The loss of one or more of these significant purchasers, and our inability to sell our production to other customers on terms we consider acceptable, could materially and adversely affect our business, financial condition, results of operations and cash flow.

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

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

Our exploration and production activities, including well stimulation and completion activities such as hydraulic fracturing, are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- abnormal pressure or irregularities in geological formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- blowouts, cratering, fires, explosions and ruptures of pipelines;
- personal injuries and death; and
- natural disasters.

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

- injury or loss of life;
- damage to and destruction of property and equipment;
- damage to natural resources, including as a result of increased seismicity from the disposal of produced water or the underground migration of hydraulic fracturing fluids;
- pollution and other environmental damage, including spillage or mishandling of recovered hydraulic fracturing fluids;
- regulatory investigations and penalties;

- suspension or delay of our operations; and
- repair and remediation costs.

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

Properties that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Properties that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict with certainty in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of micro-seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogues we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions;
- loss of title or other titled related issues;
- abnormal pressure or irregularities in geological formations;
- equipment failure or accidents;
- adverse or severe weather conditions or events;
- reductions in oil, natural gas and NGLs prices;
- political events, public protests, civil disturbances, terrorist acts or cyber-attacks;
- surface access restrictions;
- failure to obtain regulatory and third-party permits and approvals;
- compliance with environmental and other governmental or contractual requirements;
- increases in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services;
- oil, natural gas or NGLs gathering, transportation, processing, fractionation, refining and export availability restrictions or limitations; and
- limited availability of financing at acceptable terms.

Multi-well pad drilling may result in volatility in our operating results.

We utilize multi-well pad drilling where practical. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production, which may cause declines or volatility in our operating results. In addition, problems affecting one pad could adversely affect production from all wells on such pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production or interruptions in ongoing production.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of producing properties or businesses that complement or expand our current business. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil, natural gas and NGLs prices and their applicable differentials;
- operating costs; and

- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain, and we may not be able to identify attractive acquisition opportunities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections may not always be performed on every well and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an “as is” basis. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Further, the success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, our Revolving Credit Agreement and the indentures governing our senior unsecured notes impose certain limitations on our ability to enter into mergers or combination transactions. These agreements also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions.

Our ability to complete divestitures of assets, or interests in assets, may be subject to factors beyond our control, and in certain cases we may be required to retain liabilities for certain matters.

From time to time, we sell an interest in a strategic asset for the purpose of assisting or accelerating the asset’s development. In addition, we regularly review our property base for the purpose of identifying non-strategic assets, the divestiture of which would increase capital resources available for other activities and create organizational and operational efficiencies. Various factors could materially affect our ability to divest such interests or non-strategic assets or complete announced divestitures, including the receipt of approvals of governmental agencies or third parties and the availability of purchasers willing to acquire the interests or purchase the non-strategic assets on terms and at prices acceptable to us.

Sellers often 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.

We are subject to complex U.S. federal, state, local and other laws and regulations related to environmental, occupational, health and safety issues that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, the occupational health and safety aspects of our operations, or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations, including: (i) the acquisition of a permit before conducting regulated drilling activities; (ii) the restriction of types, quantities and concentration of materials that can be released into the environment; (iii) the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) the application of specific health and safety criteria addressing worker protection; and (v) the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue. In addition, the trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment; if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations, our costs of compliance may increase. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard ("NAAQS") for ozone from 75 to 70 parts per billion, and the agency completed attainment/non-attainment designations in July 2018. Although all of the areas in which we operate are currently in attainment, state implementation of the revised NAAQS, or a change in the attainment status of the areas in which we operate, could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant. Failure to comply with laws and regulations applicable to our operations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition and results of operations.

Certain environmental laws impose strict as well as joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons, or solid wastes have been stored or released. We may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Moreover, public interest in the protection of the environment has increased dramatically in recent years, and many environmental statutes contain citizen suit provisions that allow private parties to sue to enforce environmental laws and regulations. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected. See "Item 1. Business—Regulation of the Oil and Natural Gas Industry" for a further description of the laws and regulations that affect us.

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

A global economic downturn, particularly with respect to the U.S. economy, and global financial and credit market disruptions could reduce the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide, which could in turn result in a further slowdown in economic activity. Reduced worldwide demand for energy often results in lower commodity prices, which will reduce our cash flows and may affect our borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves as existing reserves are depleted. In addition, if the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

If we experience liquidity concerns, we could face a downgrade in our credit ratings, which could negatively impact our cost of and ability to access capital.

As of December 31, 2018, our long-term senior secured debt was rated B1 with a stable outlook by Moody's Investors Service, Inc. and BB- with a positive outlook by Standard & Poor's Ratings Services. Since this date, no changes in our credit ratings have occurred; however, we cannot be assured that our credit ratings will not be downgraded in the future.

A downgrade in our credit ratings could negatively impact (i) our costs of capital or our ability to effectively execute aspects of our strategy, (ii) our ability to raise debt in the public debt markets (in which case, the cost of any new debt could be higher than our outstanding debt) and (iii) our ability to obtain additional financing with acceptable interest rates, fees and other terms. These and other impacts of a downgrade in our credit ratings could have a material adverse effect on our business, financial condition and results of operations.

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

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil, natural gas and NGLs prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Further, to the extent our suppliers source their products or raw materials from foreign markets, the cost of such equipment could be impacted if the United States imposes tariffs on imported goods from countries where these goods are produced. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages or cost increases could decrease our profit margin, cash flow and operating results, or restrict our ability to drill the wells and conduct the operations which we currently have planned and budgeted or which we may plan in the future.

Should we fail to comply with all applicable regulatory agency administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the Energy Policy Act of 2005, the FERC has civil penalty authority under the Natural Gas Act of 1938 to impose penalties for current violations of up to $1,269,500 per day for each violation (adjusted annually based on inflation) and disgorgement of profits associated with any violation. While our operations have not been regulated by the FERC as a natural gas company under this law, the FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting requirements. We also must comply with the anti-market manipulation rules enforced by the FERC. Additional rules and legislation pertaining to those and other matters may be considered or adopted by the FERC from time to time. Additionally, the FTC has regulations intended to prohibit market manipulation in the petroleum industry with authority to fine violators of the regulations civil penalties of up to $1 million per day and the CFTC prohibits market manipulation in the markets regulated by the CFTC, including similar anti-manipulation authority with respect to crude oil swaps and futures contracts as that granted to the CFTC with respect to crude oil purchases and sales. The CFTC rules subject violators to a civil penalty of up to the greater of $1,162,183 (adjusted annually based on inflation) or triple the monetary gain to the person for each violation. Failure to comply with those regulations in the future could subject us to civil penalty liability, as described in "Item 1. Business—Regulation of the Oil and Natural Gas Industry."

Climate change legislation, regulations restricting emissions of greenhouse gases or legal or other action taken by public or private entities related to climate change could result in increased operating costs and reduced demand for the oil and natural gas that we produce. In addition, the potential physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

In response to findings that emissions of carbon dioxide, methane and other GHGs present a danger to public health and the environment, the EPA has adopted regulations under existing provisions of the Clean Air Act that, among other things, establish PSD, construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards for these emissions. EPA rulemakings related to GHG emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the annual reporting of GHG emissions from certain petroleum and natural gas system sources in the U.S., including, among others, onshore and offshore production facilities, which include certain of our operations.

Furthermore, in June 2016, the EPA finalized rules, known as Subpart OOOOa, that establish new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. Following the change in presidential administration, there have been attempts to modify these regulations, and litigation concerning the regulations is ongoing. As a result, we cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements. However, given the long-term trend toward increasing regulation, future federal methane regulation of the oil and gas industry remains a possibility, and several states have separately imposed their own regulations on methane emissions from oil and gas production activities.

While Congress has from time to time considered legislation to reduce emissions of GHGs, no significant legislation to reduce GHG emissions has been adopted at the federal level. In the absence of Congressional action, a number of state and regional GHG restrictions have emerged. The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and gas we produce. Consequently, legislation and regulation programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Reduced demand for the oil and gas we produce could also have the effect of lowering the value of our reserves.

Demand for our products may also be adversely affected by conservation plans and efforts undertaken in response to global climate change, including plans developed in connection with the recent Paris climate conference agreement reached in December 2015, which entered into force in November 2016. However, in August 2017, the U.S. State Department officially informed the United Nations of the intent of the United States to withdraw from the Paris Climate Agreement. The United States' adherence to the exit process is uncertain and/or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time. Notwithstanding potential risks related to climate change, the

International Energy Agency estimates that global energy demand will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. It should also be noted that many scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits brought by public and private entities against oil and gas companies in connection with their GHG emissions. Should we be targeted by any such litigation, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to causation or contribution to the asserted damage, or to other mitigating factors.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays and could materially and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, resulting in new legislative and regulatory initiatives that seek to increase the regulatory burden imposed on hydraulic fracturing.

At the federal level, the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities. Further, the EPA finalized regulations under the CWA in June 2016 prohibiting wastewater discharges from hydraulic fracturing and certain other natural gas operations to publicly owned wastewater treatment plants. Also, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain limited circumstances. The report does not appear to provide a basis for additional federal regulation of hydraulic fracturing at this time.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of, or prohibiting, drilling or hydraulic fracturing activities. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we may be required to incur significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities and perhaps even be precluded from drilling wells.

Further regulation of hydraulic fracturing at the federal, state and local level could subject our operations to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves. Please read "Item 1. Business—Regulation of the Oil and Natural Gas Industry" for a further description of the laws and regulations that affect us.

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

Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations or materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. For example, recently, there have been renewed calls to review protections currently in place for the dunes sagebrush lizard, whose habitat includes portions of the Permian Basin, and to reconsider listing the species under the ESA. The designation as threatened or endangered of previously unprotected species in areas where we operate could cause us to incur increased costs arising from species protection measures or could result in limitations on our development and production activities that could have a material adverse impact on our ability to develop and produce our reserves.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties and market oil or natural gas.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources than us. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Because we have fewer financial and human resources than many companies in our industry, we may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons and raising additional capital, which could have a material adverse effect on our business.

We operate in areas of high industry activity, which may affect our ability to hire, train or retain qualified personnel needed to manage and operate our assets.

Our operations and drilling activity are concentrated in the Permian Basin in west Texas, an area in which industry activity has increased rapidly in recent years. As a result, demand for qualified personnel in this area, and the cost to attract and retain such personnel, has increased over the past few years due to competition and could increase in the future if commodity prices rebound. Moreover, our competitors may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer.

Any delay or inability to secure the personnel necessary for us to continue or complete our current and planned development activities could lead to a reduction in production volumes. In addition, any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on our results of operations, liquidity and financial condition.

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel could have a material adverse effect on our business, financial condition and results of operations.

We are susceptible to the potential difficulties associated with rapid growth and expansion and have a limited operating history.

We have grown rapidly over the last several years. Our management believes that our future success depends on our ability to manage the growth that we have experienced and the demands from increased responsibility on management personnel. The following factors could present difficulties:

- increased responsibilities for our executive level personnel;
- increased administrative burdens; and
- increased organizational challenges common to large, expansive operations.

Our operating results could be adversely affected if we do not successfully manage these potential difficulties. The historical financial information incorporated herein is not necessarily indicative of the results that may be realized in the future. In addition, our operating history is limited and the results from our current producing wells are not necessarily indicative of success from our future drilling operations.

Part of our strategy involves drilling in existing or emerging shale plays using the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers. As of December 31, 2018, we had placed on production 427 gross (394.3 net) horizontal wells and therefore are subject to increased risks associated with horizontal drilling as compared to companies that have greater experience in horizontal drilling activities. Risks that we face while drilling include, but are not limited to, failing to land our wellbore in the desired drilling zone, not staying in the desired drilling zone while drilling horizontally through the formation, not running our casing the entire length of the wellbore and not being able to run tools and other equipment consistently through the horizontal wellbore. Risks that we face while completing our wells include, but are not limited to, not being able to fracture stimulate the planned number of stages, not being able to run tools the entire length of the wellbore during completion operations and not successfully cleaning out the wellbore after completion of the final fracture stimulation stage. Furthermore, certain of the new techniques we are adopting, such as well-spacing optimization and multi-well pad drilling, may impact the volumes of oil and gas that we ultimately recover and cause irregularities or interruptions in production due to the time required to drill and complete multiple wells before any such wells begin producing. The results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established practices. Newer or emerging formations and areas often have limited or no production history and consequently we are less able to predict future drilling results in these areas, particularly to the extent that development in these areas requires the use of new drilling and completion techniques. Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are worse than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and/or commodity price declines, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline in the future.

Factors affecting the cost and availability of credit could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in our credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. Potential disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital and a significant increase in the cost of, or reduction in the availability of, credit could materially and adversely affect our ability to achieve our planned growth and operating results.

Our ability to use our net operating loss carryforwards may be limited.

As of December 31, 2018, we had approximately $1.4 billion of U.S. federal net operating loss carryforwards (“NOLs”), which begin to expire in 2034. Utilization of these NOLs depends on many factors, including our future income, which cannot be assured. In addition, Section 382 of the Internal Revenue Code of 1986, as amended (“Section 382”), generally imposes an annual limitation on the amount of NOLs that may be used to offset taxable income when a corporation has undergone an “ownership change” (as determined under Section 382). An ownership change generally occurs if one or more stockholders (or groups of stockholders) who are each deemed to own at least 5% of our stock change their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period. In the event that an ownership change has occurred, or were to occur, utilization of our NOLs would be subject to an annual limitation under Section 382, determined by multiplying the value of our stock at the time of the ownership change by the applicable long-term tax-exempt rate as defined in Section 382, subject to certain adjustments. Any unused annual limitation may be carried over to later years. We cannot assure you that we will not undergo an ownership change in 2019. However, even if we did have an ownership change in 2019, we do not believe that the resulting Section 382 annual limitation would prevent our utilization of our NOLs prior to their expiration. Future ownership changes or future regulatory changes could limit our ability to utilize our NOLs. To the extent we are not able to offset our future income with our NOLs, this would adversely affect our operating results and cash flows if we attain profitability.

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

Even when properly used and interpreted, 2-D and 3-D 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. In addition, the use of 3-D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

Derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity prices, interest rates and other risks associated with our business.

The Dodd-Frank Act, among other things, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The CFTC has finalized certain of its regulations under the Dodd-Frank Act, but others remain to be finalized or implemented. It is not possible at this time to predict when this will be accomplished or what the terms of the final rules will be, so the impact of those rules is uncertain at this time.

The CFTC has designated certain types of swaps (thus far, only certain interest rate swaps and credit default swaps) for mandatory clearing and exchange trading, and may designate other types of swaps for mandatory clearing and exchange trading in the future. To the extent we engage in such transactions or such transactions become subject to such rules in the future, we will be required to comply or to take steps to qualify for an exemption to such requirements. Although we are availing ourselves of the end-user exception to the mandatory clearing and exchange trading requirements for swaps designed to hedge our 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 we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, or if the cost of entering into uncleared swaps becomes prohibitive, we may be required to clear such transactions or execute them on a derivatives contract market or swap executive facility.

In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception from margin requirements for swaps to other market participants, such as swap dealers, these rules may change the cost and availability of the swaps we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, we could be required to post initial or variation margin, which would impact liquidity and reduce our cash. This would in turn reduce our ability to execute hedges to reduce risk and protect cash flows.

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 we encounter and reduce our ability to monetize or restructure our existing commodity price contracts. If we reduce our use of commodity price contracts as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and make cash distributions to our unitholders. Further, to the extent our revenues are unhedged, they could be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices.

We may not be able to keep pace with technological developments in our industry.

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs. In addition, other oil and natural gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and that may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete, our business, financial condition or results of operations could be materially and adversely affected.

Our business could be negatively affected by security threats, including cybersecurity threats and other disruptions.

As an oil and natural gas producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the security of our 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 our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, data, 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 our operations and could have a material adverse effect on our reputation, financial position, results of operations and cash flows. Cybersecurity attacks in particular are becoming more sophisticated and have increased in frequency. We rely 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 our business. Our information and technology systems and networks, as well as those of third parties we use in our operations, may become the target of cybersecurity attacks, including, without limitation, malicious software, attempts to gain unauthorized access to data and systems and other electronic security breaches that could lead to disruptions in critical systems and could materially and adversely affect us 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 our ability to compete for oil and gas resources;
- data corruption or operational disruption of production infrastructure, which could result in loss of production or accidental discharge;
- a cyber-attack resulting in the loss or disclosure of, or damage to, our or any of our customers' or suppliers' data or confidential information, which could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps;
- a cyber-attack on a vendor or service provider, which could result in supply chain disruptions and could delay or halt operations; and
- a cyber-attack on third-party gathering, transportation, processing, fractionation, refining or export facilities, which could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues.

These events could damage our 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. Our systems and insurance coverage for protecting against cyber security risks may not be sufficient. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Risks Related to our Common Stock

We are a holding company. Our sole material asset is our equity interest in Parsley LLC and we are accordingly dependent upon distributions from Parsley LLC to pay taxes, make payments under the TRA and cover our corporate and other overhead expenses.

We are a holding company and have no material assets other than our equity interest in Parsley LLC. We have no independent means of generating revenue. To the extent Parsley LLC has available cash, we intend to cause Parsley LLC to make (i) generally pro rata distributions to the PE Unit Holders, including us, in an amount sufficient to allow all such holders, including us, to pay their respective taxes (at assumed tax rates) and to allow us to make payments under the TRA and (ii) non-pro rata payments to us to reimburse us for our corporate and other overhead expenses. We are limited, however, in our ability to cause Parsley LLC and its subsidiaries to make these and other distributions to us due to the restrictions under our Revolving Credit Agreement and the indentures governing our senior unsecured notes. To the extent that we need funds and Parsley LLC or its subsidiaries are restricted from making such distributions under applicable law or regulation or under the terms of their financing arrangements, or are otherwise unable to provide such funds, it could materially adversely affect our liquidity and financial condition.

Our management collectively holds a significant percentage of the voting power of our common stock.

Holders of our Class A common stock and Class B common stock vote together as a single class on all matters presented to our stockholders for their vote or approval, except as otherwise required by applicable law or our certificate of incorporation. As of December 31, 2018, our executive officers held voting power over approximately 12.4% of our outstanding common stock. The existence of this significant management ownership position may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company.

So long as the members of our management team continue to control a significant percentage of the voting power of our common stock, they will continue to be able to strongly influence all matters requiring stockholder approval, regardless of whether or not other stockholders believe that a potential transaction is in their best interests. In any of these matters, the interests of our management team may differ or conflict with the interests of our other stockholders.

We have engaged in transactions with our affiliates and expect to do so in the future. The terms of such transactions and the resolution of any conflicts that may arise may not always be in our or our stockholders' best interests.

We have engaged in transactions and expect to continue to engage in transactions with affiliated companies, as described under the caption "Item 13. Certain Relationships and Related Transactions and Director Independence." These transactions, and the resolution of any conflicts that may arise in connection with such related party transactions, including pricing, duration or other terms of service, may not always be in our or our stockholders' best interests.

Our certificate of incorporation and bylaws contain provisions that make it more difficult to effect a change of control of the Company, which may adversely affect the market price of our Class A common stock.

The existence of some provisions of our certificate of incorporation and our bylaws could delay or prevent a change of control of the Company, even if the change of control would be beneficial to our stockholders, including:

- a classified board of directors, with only approximately one-third of our board of directors elected each year;
- limitations on the removal of directors, including the requirement that a director may only be removed for cause and upon the affirmative vote of the holders of at least two-thirds of the outstanding shares of stock of the Company entitled to vote generally for the election of directors;
- the inability of our stockholders to call special meetings or act by written consent;
- the ability of our board of directors to adopt, alter or repeal our bylaws and the requirement that the affirmative vote of holders representing at least two-thirds of the voting power of all outstanding shares of stock of the Company be obtained for stockholders to amend, alter or repeal our bylaws;
- the requirement that the affirmative vote of holders representing at least two-thirds of the voting power of all outstanding shares of stock of the Company be obtained to amend, alter or repeal any provision of our certificate of incorporation;
- provisions regulating the ability of our stockholders to nominate directors for election or to bring matters for action at annual meetings of our stockholders; and
- the authorization given to our board of directors to issue and set the terms of preferred stock without the approval of our stockholders.

These provisions also could discourage proxy contests and make it more difficult for you and other stockholders to elect directors and take other actions. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price that investors are willing to pay in the future for shares of our common stock. In addition, certain change of control events have the effect of accelerating any payments due under our Revolving Credit Agreement and the TRA, and could, in certain circumstances, accelerate payments required by the indentures governing our senior unsecured notes, which could be substantial and accordingly serve as a disincentive to a potential acquirer of our company. Please see "—In certain cases, payments under the TRA may be accelerated and/or significantly exceed the actual benefits, if any, we realize in respect of the tax attributes subject to the TRA."

Our certificate of incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents.

Our certificate of incorporation provides that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf, (ii) any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our stockholders, (iii) any action asserting a claim against us or any director or officer or other employee of ours arising pursuant to any provision of the Delaware General Corporation Law, our certificate of incorporation or our bylaws, or (iv) any action asserting a claim against us or any director or officer or other employee of ours that is governed by the internal affairs doctrine, in each such case subject to such Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein. This choice of forum provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers, employees or agents, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our certificate of incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition or results of operations.

We do not intend to pay dividends on our Class A common stock or Class B common stock in the near future, and our Revolving Credit Agreement and the indentures governing our senior unsecured notes place certain restrictions on our ability to do so. Consequently, your only opportunity to achieve a return on your investment is if the price of our Class A common stock appreciates.

We have never declared or paid any dividends to holders of our Class A common stock or Class B common stock. We currently intend to retain all available funds, if any, to finance the development and expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities. Additionally, our Revolving Credit Agreement and the indentures governing our senior unsecured notes place certain restrictions on our ability to pay cash dividends. Consequently, investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment.

There may be future dilution of our common stock, which could adversely affect the market price of our Class A common stock.

In the future, we may issue shares of common stock to raise cash for future capital expenditures, acquisitions or for general corporate purposes. We may also acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities convertible into, exchangeable for or that represent the right to receive our common stock. Lastly, we issue restricted share awards, restricted stock units and other incentive compensation to our employees and directors as part of their compensation. Any of these events will dilute our stockholders' ownership interest in us and may reduce our earnings per share and have an adverse effect on the price of our Class A common stock. In addition, sales of a substantial amount of our common stock in the public market, or the perception that these sales may occur, could reduce the market price of our Class A common stock. This could also impair our ability to raise capital through the sale of our securities.

We are required to make payments under the TRA for certain tax benefits we may claim, and the amounts of such payments could be significant.

The PE Unit Holders generally have the right to exchange their PE Units (and a corresponding number of shares of Class B common stock) for shares of our Class A common stock at an exchange ratio of one share of Class A common stock for each PE Unit (and corresponding share of Class B common stock) exchanged (subject to conversion rate adjustments for stock splits, stock dividends and reclassifications), or, if either we or Parsley LLC so elects, cash.

We have entered into the TRA with Parsley LLC and the TRA Holders. The TRA generally provides for the payment by us to each TRA Holder of 85% of the net cash savings, if any, in U.S. federal, state and local income tax or franchise tax that we actually realize (or are deemed to realize in certain circumstances) in periods after our IPO as a result of certain increases in tax basis and certain benefits attributable to imputed interest. We will retain the benefit of the remaining 15% of these cash savings. Payments we make under the TRA will be increased by any interest accrued from the due date (without extensions) of the corresponding tax return.

The term of the TRA commenced upon the completion of our IPO and will continue until all tax benefits that are subject to the TRA have been utilized or have expired, unless we exercise our right to terminate the TRA (or the TRA is terminated due to other circumstances, including our breach of a material obligation thereunder or certain mergers or other changes of control), and we make the termination payment specified in the TRA.

Estimating the amount and timing of payments that may become due under the TRA is by its nature imprecise. For purposes of the TRA, cash savings in tax generally are calculated by comparing our actual tax liability to the amount we would have been required to pay had we not been able to utilize any of the tax benefits subject to the TRA. The amount and timing of any payments under the TRA are dependent upon significant future events and assumptions, including the timing of the exchanges of PE Units, the price of Class A common stock at the time of each exchange, the extent to which such exchanges are taxable, the amount of the exchanging TRA Holder's tax basis in its PE Units at the time of the relevant exchange, the depreciation and amortization periods that apply to the increase in tax basis, the amount and timing of the taxable income we generate in the future and the tax rate then applicable, and the portion of our payments under the TRA constituting imputed interest or giving rise to depletable, depreciable or amortizable basis.

The payment obligations under the TRA are our obligations and not obligations of Parsley LLC, and we expect that the payments we will be required to make under the TRA could be substantial. We are a holding company with no independent means of generating revenue. Therefore, to the extent Parsley LLC has available cash, we intend to cause Parsley LLC to make pro rata distributions to the PE Unit Holders, including us, in an amount sufficient to allow us to cover all such TRA payment obligations. The ability of Parsley LLC and its subsidiaries to make such distributions will be subject to, among other things, the applicable provisions of Delaware law and restrictions under our Revolving Credit Agreement and the indentures governing our senior unsecured notes (or other applicable instruments issued by Parsley LLC or its subsidiaries). To the extent that we are unable to make payments under the TRA for any reason, such payments will be deferred and will accrue interest until paid. The payments under the TRA are not conditioned upon a holder of rights under the TRA having a continued ownership interest in us.

In certain cases, payments under the TRA may be accelerated and/or significantly exceed the actual benefits, if any, we realize in respect of the tax attributes subject to the TRA.

If we experience a change of control (as defined under the TRA, which includes certain mergers, asset sales and other forms of business combinations) or the TRA terminates early (at our election or due to a material breach of the TRA), we would be required to make a substantial, immediate lump-sum payment equal to the present value of hypothetical future payments that could be required to be paid under the TRA (determined by applying a discount rate of one-year LIBOR plus 3%). The calculation of hypothetical future payments will be based upon certain assumptions and deemed events as set forth in the TRA, including that we have sufficient taxable income to fully utilize such benefits and that any PE Units that the TRA Holders or their permitted transferees own on the termination date are deemed to be exchanged on the termination date. Any early termination payment may be made significantly in advance of, and may materially exceed, the actual realization, if any, of the future tax benefits to which the termination payment relates.

In these situations, our obligations under the TRA could have a substantial negative impact on our liquidity and could have the effect of delaying, deferring or preventing certain mergers, asset sales, other forms of business combinations or other changes of control due to the additional transaction costs a potential acquirer may attribute to satisfying such obligations. For example, if the TRA were terminated at December 31, 2018, the estimated termination payment would be approximately $119.3 million (calculated using a discount rate of LIBOR plus 3%, applied against an undiscounted liability of $242.9 million). The foregoing number is merely an estimate and the actual payment could differ materially. There can be no assurance that we will be able to finance our obligations under the TRA.

In the event that our payment obligations under the TRA are accelerated upon certain mergers, other forms of business combinations or other changes of control, the consideration payable to holders of our Class A common stock could be substantially reduced.

If we experience a change of control (as defined under the TRA, which includes certain mergers, asset sales and other forms of business combinations), we would be obligated to make a substantial, immediate lump-sum payment, and such payment may be significantly in advance of, and may materially exceed, the actual realization, if any, of the future tax benefits to which the payment relates. As a result of this payment obligation, holders of our Class A common stock could receive substantially less consideration in connection with a change of control transaction than they would receive in the absence of such obligation. Further, our payment obligations under the TRA will not be conditioned upon the TRA Holders' having a continued interest in us or Parsley LLC. Accordingly, the TRA Holders' interests may conflict with those of the holders of our Class A common stock.

We will not be reimbursed for any payments made under the TRA in the event that any tax benefits are subsequently disallowed.

Payments under the TRA will be based on the tax reporting positions that we will determine. The TRA Holders will not reimburse us for any payments previously made under the TRA if any tax benefits that have given rise to payments under the TRA are subsequently disallowed, except that excess payments made to any TRA Holder will be netted against payments that would otherwise be made, if any, to such holder after our determination of such excess. As a result, in such circumstances, we could make payments that are greater than our actual cash tax savings, if any and may not be able to recoup those payments, which could adversely affect our liquidity.

In certain circumstances, Parsley LLC will be required to make tax distributions to the PE Unit Holders, including us, and such tax distributions may be substantial. To the extent we receive tax distributions in excess of our tax liabilities and obligations to make payments under the TRA and do not distribute such cash balances as dividends on our Class A common stock, the holders of the Exchange Right would benefit from such accumulated cash balances if they exercise their Exchange Right.

Parsley LLC is treated as a partnership for U.S. federal income tax purposes and, as such, is not subject to U.S. federal income tax. Instead, any taxable income is allocated to the PE Unit Holders, including us. Pursuant to the Parsley LLC Agreement, Parsley LLC will make pro rata cash distributions, or tax distributions, to the PE Unit Holders, including us, in an amount sufficient to allow each of the PE Unit Holders to pay its respective taxes (at assumed tax rates) on such holder's allocable share of any taxable income of Parsley LLC. Under applicable tax rules, Parsley LLC is required to allocate net taxable income disproportionately to its members in certain circumstances. Because tax distributions are determined based on the PE Unit Holder who is allocated the largest amount of taxable income on a per unit basis and on an assumed tax rate that is the highest possible rate applicable to any PE Unit Holder, but are made pro rata based on ownership, Parsley LLC may be required to make tax distributions that, in the aggregate, exceed the amount of taxes that Parsley LLC would have paid if it were taxed on its net income at the assumed rate. The pro rata distribution amounts may also be increased to the extent necessary to ensure that the amount distributed to us is sufficient to enable us to pay any amounts payable under the TRA.

Funds used by Parsley LLC to satisfy its tax distribution obligations will not be available for reinvestment in our business. Moreover, the tax distributions Parsley LLC will be required to make may be substantial, and may exceed (as a percentage of Parsley LLC's income) the overall effective tax rate applicable to a similarly situated corporate taxpayer. In addition, because these payments will be calculated with reference to an assumed tax rate, and because of the disproportionate allocation of net taxable income, these payments may significantly exceed the actual tax liability for many of the PE Unit Holders, including us.

As a result of potential differences in the amount of net taxable income allocable to us and to the other PE Unit Holders, as well as the use of an assumed tax rate in calculating Parsley LLC's tax distribution obligations, we may receive distributions significantly in excess of our tax liabilities and obligations to make payments under the TRA. If we do not distribute such cash balances as dividends on our Class A common stock and instead, for example, hold such cash balances or lend them to Parsley LLC, the holders of the Exchange Right would benefit from any value attributable to such accumulated cash balances as a result of their ownership of Class A common stock following an exchange of their Parsley LLC Units pursuant to the Exchange Right or their receipt of an equivalent amount of cash.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

We are subject to certain requirements of Section 404 of the Sarbanes-Oxley Act. If we fail to comply with the requirements of Section 404 or if we or our auditors identify and report material weaknesses in internal control over financial reporting, our investors may lose confidence in our reported information and our stock price may be negatively affected.

We are required to comply with certain provisions of Section 404 of the Sarbanes-Oxley Act of 2002 (the "Sarbanes-Oxley Act"). Section 404 requires that we document and test our internal control over financial reporting and issue our management's assessment of our internal control over financial reporting. This section also requires that our independent registered public accounting firm issue an attestation report on such internal control. If we fail to comply with the requirements of Section 404 of the Sarbanes-Oxley Act, or if we or our auditors identify and report material weaknesses in our internal control over financial reporting, the accuracy and timeliness of the filing of our annual and quarterly reports may be materially adversely affected and could cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our Class A common stock. In addition, a material weakness in the effectiveness of our internal control over financial reporting could result in an increased chance of fraud and the loss of customers, reduce our ability to obtain financing and require additional expenditures to comply with these requirements, each of which could have a material adverse effect on our business, results of operations and financial condition.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Our properties are located in the west Texas portion of the Permian Basin. As of December 31, 2018, our acreage position consisted of 267,143 gross (198,946 net) acres, and approximately 76% of our net acres were held by production. As of December 31, 2018, we had interests in 571 gross (442.7 net) producing horizontal wells, of which we operate 453 gross (425.3 net) of the horizontal wells, and interests in 1,244 gross (779.7 net) producing vertical wells, of which we also operate 919 gross (735.7 net) of the vertical wells.

The Permian Basin extends through multiple counties in west Texas and southeastern New Mexico and covers an area some 250 miles wide and 300 miles long. It is comprised of three main sub-areas, the Midland Basin, the Delaware Basin and the Central Basin Platform. Historically, conventional reservoirs have been targeted and successfully produced in all three sub-areas. Over the past 30 years, there has been an increase in multi-stage fracturing treatments targeting and commingling production from multiple tight, stacked pay, unconventional target zones. With the advent of horizontal drilling and the application of multi-stage fracture treatments within one horizontal wellbore, activity has significantly increased, with operators generally targeting one zone at a time.

Core Area Descriptions

We group our assets by area based on similar geologic, economic and technical requirements. We split our assets into two areas, the Midland Basin and the Delaware Basin.

Midland Basin

Throughout the middle and late Pennsylvanian period, the Midland Basin was a very shallow and generally poorly defined area dominated by marine shale and limestone deposition. Organic content of the marine shale increased as the basin slowly subsided. Tectonic uplift of the Central Basin Platform and the coincident emergence of the Eastern Shelf during the early Permian period brought greater definition to the Midland Basin as a distinct physiographic feature. Slow subsidence and basin filling with organic shale and limestone continued to dominate deposition. During the middle Permian period, more emergent surrounding shelf areas to the northwest and south-southwest contributed thick volumes of clastic sand that molded with the shale and limestone and formed the widespread Spraberry target zone throughout the Permian Basin. In the later Permian period, there was basin-wide infilling and subsequent burial with massive evaporate deposition.

The Midland Basin has historically been characterized by production from its most prolific field, the Spraberry Trend Area. The Spraberry Trend Area has been heavily drilled since the discovery of the Seaboard No. 2-D Lee well in Dawson County, Texas in 1949. The zone stretches over 150 miles north to south and over 75 miles east to west. Additionally, activity targeting the deeper Wolfcamp zone increased dramatically after Henry Petroleum started drilling fully through the Wolfcamp zone in the early 2000s. In the late 2000s and early 2010s, many operators, including us, had success commingling still deeper production from the Upper Pennsylvanian (Cline), Strawn and Atoka zones. Concurrently, operators started testing zones singularly with horizontal wells and multi-stage treatments. To date, operators have drilled horizontal wells in multiple zones within the Midland Basin.

As of December 31, 2018, we held 218,525 gross (154,107 net) acres in our Midland Basin area. Approximately 76% of our net acreage in this area is held by production. We had interests in 467 gross (357.5 net) producing horizontal wells in the Midland Basin as of December 31, 2018, and we operated 364 gross (340.8 net) of the horizontal wells in the Midland Basin. We also had interests in 1,176 gross (767.2 net) producing vertical wells.

Following the commencement of our horizontal drilling program in 2013 through December 31, 2018, we have placed on production 357 gross (326.6 net) horizontal wells in the Midland Basin. The table below summarizes the horizontal wells placed on production in the Midland Basin in the periods indicated:

Year ended December 31, (1)(2)					
2018		2017		2016	
Gross	Net	Gross	Net	Gross	Net
132	127.9	96	89.5	71	64.8

(1) Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly exploratory wells for which there is no production history.

(2) During the periods presented, we have not drilled any dry development wells, productive exploratory wells or dry exploratory wells.

Delaware Basin

From the mid-Pennsylvanian period to the early Permian period, the Delaware Basin was a slowly subsiding area that was characterized by shallow marine shales and limestone. Influxes of clastic sands generally occurred as turbidite deposits formed during periodic sea-level changes. Records indicate a rapid deepening of the Delaware Basin relative to the emergent Central Basin Platform, during the early Permian period. Marine shale deposition continued to dominate the basin during this period. Episodic pulses of carbonate and clastic debris and density flows punctuated the shale deposition and eventually became significant reservoirs. Through the late Permian period, the basin became increasingly more clastic dominated as emergent shelf areas to the north shed sands into the basin.

As of December 31, 2018, we held 48,618 gross (44,839 net) acres in our Delaware Basin area. Approximately 77% of our net acreage in this area is held by production; however, we hold mineral interests in a significant portion of our Delaware Basin leasehold acreage, which ensures our ability to continue producing from this area. As of December 31, 2018, we had interests in 104 gross (85.2 net) producing horizontal wells in the Delaware Basin, of which 89 gross (84.5 net) horizontal wells were operated by us. We also had interests in 68 gross (12.5 net) producing vertical wells in the Delaware Basin as of December 31, 2018.

Following the commencement of our horizontal drilling program in 2013 through December 31, 2018, we have placed on production 70 gross (67.7 net) horizontal wells in the Delaware Basin. The table below summarizes the horizontal wells placed on production in the Delaware Basin in the periods indicated:

Year ended December 31, (1)(2)					
2018		2017		2016	
Gross	Net	Gross	Net	Gross	Net
43	41.9	21	19.9	5	4.8

(1) Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly exploratory wells for which there is no production history.

(2) During the periods presented, we have not drilled any dry development wells, productive exploratory wells or dry exploratory wells.

Production Status

For the year ended December 31, 2018, our average daily net sales from our wells on our Midland Basin acreage was 86,127 Boe/d, of which 60% was from oil, 17% was from natural gas and 23% was from NGLs. Over the same period, our average daily net sales from our wells on our Delaware Basin acreage was 23,289 Boe/d, of which 76% was from oil, 11% was from natural gas and 13% was from NGLs.

Operational Facilities

Our land-based oil and natural gas processing facilities are typical of those found in the Permian Basin. Our facilities at well locations or centralized lease locations include storage tank batteries, oil/natural gas/water separation equipment, and pumping units. In addition, throughout our acreage, we own and operate facilities with significant water sourcing, transfer, and disposal capacity.

Recent Activity

During the year ended December 31, 2018, we spud 132 gross (127.9 net) horizontal wells and two gross (1.7 net) vertical wells on our Midland Basin acreage. We also spud 38 gross (37.3 net) horizontal wells on our Delaware Basin acreage.

During the year ended December 31, 2018, we incurred costs of approximately $1,096.3 million and $408.6 million for our Midland Basin and Delaware Basin horizontal drilling and completions, respectively. We incurred costs of approximately $5.2 million for vertical drilling, completions and recompletions. We also incurred costs of approximately $252.1 million associated with facilities and infrastructure.

The amount and timing of our future capital expenditures is largely discretionary and within our control. We could choose to defer a portion of planned capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners.

Production, Price and Cost Data

The following table sets forth information regarding our production of oil, natural gas and NGLs and certain price and cost information, for the periods indicated:

	Year ended December 31,		
	2018	**2017**	**2016**
Average daily production volume:			
Oil (Bbls/d)	69,468	44,904	25,596
Natural gas (Mcf/d)	102,370	63,907	36,784
Natural gas liquids (Bbls/d)	22,885	12,362	6,530
Total (Boe/d)	109,416	67,923	38,257
Average realized prices:			
Oil, without realized derivatives (per Bbls)	$ 60.59	$ 48.95	$ 41.34
Oil, with realized derivatives (per Bbls)	58.07	47.68	47.56
Natural gas, without realized derivatives (per Mcf)	1.37	2.43	2.30
Natural gas, with realized derivatives (per Mcf)	1.38	2.40	2.30
Natural gas liquids (per Bbls)	27.21	22.87	16.01
Average price per Boe, without realized derivatives	45.44	38.80	32.60
Average price per Boe, with realized derivatives	43.85	37.94	36.76
Average production costs (per Boe) [1]**:**			
Lease operating expenses	$ 3.61	$ 4.12	$ 4.23
Transportation and processing costs	0.82	—	—
Production and ad valorem taxes:			
Production	2.25	1.98	1.64
Ad valorem	0.46	0.43	0.35
Total	$ 2.71	$ 2.41	$ 1.99
Depreciation, depletion and amortization	$ 14.64	$ 14.21	$ 16.70

(1) Average production costs per Boe for the year ended December 31, 2018 reflect adjustments associated with our adoption of ASC 606, effective January 1, 2018.

For additional information, see "Item 1. Business—Oil and Natural Gas Production Prices and Production Costs—Production and Price History," which is incorporated herein by reference.

Evaluation and Review of Proved Reserves

Estimates of our proved reserves as of December 31, 2018, 2017 and 2016 were based on evaluations prepared by our internal staff of petroleum engineers and audited by NSAI. We have no oil and natural gas reserves from non-traditional sources. Additionally, we do not provide optional disclosure of probable or possible reserves. NSAI does not own an interest in any of our properties, nor is it employed by us on a contingent basis.

Reserve estimation procedures. We maintain an internal staff of petroleum engineers and geoscience professionals (the "Reserves Group") to ensure the integrity, accuracy and timeliness of the data used in our reserves estimation process. We have 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 process by our Vice President—Reservoir Engineering and Planning who reports directly to our Executive Vice President—Chief Operating Officer as well as annual external audits of our proved reserves by NSAI.

In addition, we maintain a Reserves Planning and Disclosure Committee that is chaired by our Vice President—Reservoir Engineering and Planning. The Reserves Planning and Disclosure Committee is also comprised of certain members of our management team and other employees relevant to the reserves process. The Reserves Planning and Disclosure Committee meets on a regular basis to review our reserves estimates, advise management of any material reserve adjustments and review and approve our annual reserve estimates filed with the SEC and any other public disclosure of reserve estimates. We also maintain a Reserves Committee of our board of directors (the "Reserves Committee") that meets regularly to, among other things, review our reserves estimates, advise our board of directors on any material reserve adjustments, review and approve our annual reserves estimates filed with the SEC and periodically interface with our independent, third-party petroleum consulting firm.

The reserve estimates are summarized in reserve reconciliations that quantify reserve changes from 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 the Reserves Group, in consultation with our accounting and financial management personnel. Annually, our Executive Vice President—Chief Operating Officer, Vice President—Reservoir Engineering and Planning and the Reserves Planning and Disclosure Committee review the reserve estimates and any differences with the reserve auditors on a consolidated basis before these estimates are approved by the Reserves Committee and our board of directors.

Reserve information as well as models used to estimate such reserves are stored on secured databases. Non-technical information used in reserve estimation models, including oil, natural gas and NGLs prices, production costs, transportation costs, future capital expenditures and our net ownership percentages are obtained from other departments. Internally, we conduct testing with respect to such non-technical inputs.

Proved reserves audits. The proved reserve audits performed by NSAI for the year ended December 31, 2018, in the aggregate, represented 100% of our year-end 2018 proved reserves, and 100% of our year-end 2018 associated pre-tax present value of proved reserves discounted at ten percent.

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 its 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 our proved reserves and associated pre-tax present value of proved reserves discounted at 10%, the Reserves Group provided to NSAI its external and internal engineering and geoscience technical data and analyses. NSAI accepted without independent verification the accuracy and completeness of the historical information and data furnished by us with respect to ownership interest, oil and natural 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 our proved reserves and the pre-tax present values of such reserves discounted at 10%. NSAI reviewed its audit differences with us, and, as necessary, held meetings with us to review additional reserves work performed by our 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 10% did not differ from our estimates by more than 10% in the aggregate. However, when compared on a lease-by-lease basis, some of our 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 10% in the aggregate and NSAI is satisfied that the proved reserves and pre-tax present values of such reserves discounted at 10% are reasonable and that its audit objectives have been met, NSAI will issue an unqualified audit opinion. 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 Annual Report, that our estimates of our proved oil and natural gas reserves and associated pre-tax present values discounted at 10% 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" promulgated by the SPE.

Qualifications of proved reserves preparers and auditors. The Reserves Group is staffed by petroleum and geoscience professionals with extensive industry experience and the process is managed by our Vice President—Reservoir Engineering and Planning, the technical person primarily responsible for overseeing the preparation of all of our reserve estimates. The qualifications of our Vice President—Reservoir Engineering and Planning include over 16 years of reservoir and operations experience. She holds a Bachelor of Science in Petroleum Engineering and a Master of Science in Global Energy Management. She is also a member of multiple professional industry organizations. Our Vice President—Reservoir Engineering and Planning reports directly to our Executive Vice President—Chief Operating Officer, whose qualifications include over 15 years of reservoir and operations experience. He graduated with a Bachelor of Science in Petroleum Engineering and a Master of Business Administration and is a member of various professional industry organizations. Our Reserves Group has an average of approximately 12 years of industry experience per person.

As described above, following the preparation of our reserves estimates, these estimates are audited for their reasonableness by NSAI. 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 our reserves estimates has been a practicing consulting petroleum engineer at NSAI since 1998 and has over 37 years of practical experience in petroleum engineering 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" promulgated by the SPE.

Estimation of Proved Reserves. Under SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered." All of our proved reserves as of December 31, 2018 and 2017 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and natural gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (1) production performance-based methods; (2) material balance-based methods; (3) volumetric-based methods; and (4) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. We believe that these methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for our properties, due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

To audit our estimates of economically recoverable proved reserves and related future net cash flows, NSAI considered many factors and assumptions, including the use of reservoir parameters derived from geological and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates. The current pricing environment could impact future economics.

Under SEC rules, reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the target zone being evaluated or in an analogous target zone. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves have been demonstrated to yield results with consistency and repeatability and include production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, historical well cost and operating expense data.

The following table sets forth the combined production volumes and reserves by area (in MBoe):

	Year Ended December 31, 2018	December 31, 2018	
	Production Volumes	Proved Developed Reserves	Proved Reserves
Midland Basin	31,436	258,018	435,146
Delaware Basin	8,501	53,297	86,573
Total	39,937	311,315	521,719

Summary of Oil, Natural Gas and NGLs Reserves. The following table presents our estimated net proved oil, natural gas and NGLs reserves as of the periods indicated:

	December 31,		
	2018	2017	2016
Proved developed reserves:			
Oil (MBbls)	170,526	119,591	61,133
Natural gas (MMcf)(1)	358,733	240,337	123,946
Natural gas liquids (MBbls)(1)	81,000	49,751	24,306
Combined (MBoe)	311,315	209,399	106,097
Proved undeveloped reserves:			
Oil (MBbls)	123,920	128,940	75,403
Natural gas (MMcf)(1)	213,305	211,366	99,659
Natural gas liquids (MBbls)(1)	50,933	42,881	24,237
Combined (MBoe)	210,404	207,048	116,250
Proved reserves:			
Oil (MBbls)	294,446	248,531	136,536
Natural gas (MMcf)(1)	572,038	451,703	223,605
Natural gas liquids (MBbls)(1)	131,933	92,632	48,543
Combined (MBoe)	521,719	416,447	222,347

(1) Natural gas and NGLs volumes for the year ended December 31, 2018 reflect adjustments associated with our adoption of ASC 606, effective January 1, 2018.

Reserve engineering is and must be recognized as a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates will differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. Please read “Item 1A. Risk Factors.”

Impact of ASC Topic 606 Adoption

We adopted ASC 606 effective January 1, 2018 using the modified retrospective approach. As a result of the control model analysis discussed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Comparability of Our Financial Condition and Results of Operations—Impact of ASC Topic 606 Adoption," we modified our accounting and presentation of natural gas and NGLs sales and associated volumes, and transportation and processing costs, under certain marketing agreements. Revenues related to certain of our agreements are presented on a gross basis for amounts expected to be received from third-party customers through the marketing process. Transportation and processing costs related to these agreements, incurred prior to the transfer of control to the customer at the tailgate of the natural gas processing facilities, are presented as Transportation and processing costs on our consolidated statements of operations. Additionally, all references to production and per Boe unit costs reflect this adoption, which has the effect of increasing certain natural gas and NGLs volumes and revenues, offset by a corresponding transportation and processing expense, such that there is no change to reported net income. Refer to *Note 3—Revenue from Contracts with Customers—Impact of ASC Topic 606 Adoption* in our consolidated financial statements for additional discussion.

All comparisons to prior period sales, expenses, production volumes and unit costs reflect the changes in reporting methodology for the year ended December 31, 2018. Additionally, the changes in natural gas and NGLs reserve volumes are reflected as revisions of previous estimates.

Proved Reserves

As of December 31, 2018, our proved reserves were composed of 294,446 MBbls of oil, 572,038 MMcf of natural gas and 131,933 MBbls of NGLs, for a total of 521,719 MBoe.

The following table summarizes the changes in our proved reserves during the year ended December 31, 2018 (in MBoe):

Balance, December 31, 2017	416,447
Purchases of reserves in place	5,613
Divestures of reserves in place	(22,465)
Extensions and discoveries	159,778
Revisions of previous estimates	2,283
Production	(39,937)
Balance, December 31, 2018	521,719

Changes in our proved reserves during the year ended December 31, 2018 primarily resulted from the following significant factors:

Purchases of reserves. During the year ended December 31, 2018, we added 5,613 MBoe of proved reserves, primarily as a result of the acquisition of incremental working interests in properties and undeveloped acreage in both the Midland and Delaware Basins. For the year ended December 31, 2018, we acquired 5,550 MBoe of proved reserves in the Midland Basin and 63 MBoe of proved reserves in the Delaware Basin.

Divestiture of reserves. During the year ended December 31, 2018, we divested 22,465 MBoe of proved reserves, which includes 22,372 MBoe of proved reserves in the Midland Basin and 93 MBoe of proved reserves in the Delaware Basin.

Extensions and discoveries. Extensions and discoveries of 159,778 MBoe during the year ended December 31, 2018 resulted primarily from our successful horizontal drilling program in the Midland Basin and Delaware Basin, of which approximately 30% is associated with proved undeveloped locations.

Revisions of previous estimates. During the year ended December 31, 2018, we experienced total positive revisions of previous estimates of 2,283 MBoe. The main driver of this adjustment was due to the adoption of ASC 606, which resulted in a positive revision of 11,434 MBoe associated with natural gas and NGLs. Please refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Comparability of Our Financial Condition and Results of Operations—Impact of ASC Topic 606 Adoption." Other drivers included changes in well performance, working interest, operating expenses and pricing, which together resulted in a positive revision of 3,063 MBoe. The reclassification of certain PUD reserves to unproved reserves accounted for a 12,214 MBoe downward revision to previous estimates related to the removal of reserves for proved undeveloped locations determined to be outside of our five-year capital expenditure plan. For additional discussion, please refer to "—Capital Development Plan" below.

Production. During the year ended December 31, 2018, our production volumes were 39,937 MBoe resulting in a corresponding decrease in our proved reserves.

As of December 31, 2018, 1,320 MBoe, or less than one percent of our total proved reserves, were classified as proved developed non-producing.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2018, our proved undeveloped reserves were composed of 123,920 MBbls of oil, 213,305 MMcf of natural gas and 50,933 MBbls of NGLs, for a total of 210,404 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following table summarizes the changes in our PUDs during the year ended December 31, 2018 (in MBoe):

Balance, December 31, 2017	207,048
Purchases of reserves	3,061
Divestiture of reserves	(12,395)
Extensions and discoveries	47,998
Revisions of previous estimates	(5,630)
Transfers to proved developed	(29,678)
Balance, December 31, 2018	210,404

Changes in our PUDs during the year ended December 31, 2018 primarily resulted from the following significant factors:

Purchases of reserves. During the year ended December 31, 2018, we added 3,061 MBoe of PUDs, primarily as a result of the acquisition of undeveloped acreage in the Midland Basin.

Divestiture of reserves. During the year ended December 31, 2018, we divested 12,395 MBoe of PUDs, all of which were in the Midland Basin.

Extensions and discoveries. Extensions and discoveries of 47,998 MBoe during the year ended December 31, 2018 resulted primarily from the drilling of new wells during the year and from new proved undeveloped locations added during the year.

Revisions of previous estimates. During the year ended December 31, 2018, we experienced total negative revisions to previous PUD reserve estimates of 5,630 MBoe. The main driver of this adjustment was the reclassification of certain PUD reserves to unproved reserves, which accounted for a 12,214 MBoe downward revision to previous estimates associated with the removal of reserves for locations determined to be outside of our five-year capital expenditure plan. We also experienced positive revisions of 1,898 MBoe related to the adoption of ASC 606 and 4,686 MBoe associated with changes to our type curves, shrinkage and yield, lease operating expenses, pricing and capital expenditures. Please refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Comparability of Our Financial Condition and Results of Operations—Impact of ASC Topic 606 Adoption" for additional discussion.

Transfers to proved developed. During the year ended December 31, 2018, we transferred 29,678 MBoe of PUDs to proved developed. This includes all proved undeveloped locations that were scheduled to be transfered to proved developed during 2018 as of December 31, 2017.

Capital Development Plan

At the end of each year, we schedule a five-year capital expenditure plan based on our best available data and financial feasibility at the time the plan is developed. In connection with the adoption of our capital expenditure plan, we prepare a field-level plan that includes the timing, location and capital commitment of wells that we expect to be drilled. Our capital expenditure plan includes only PUD reserves that we are reasonably certain, based on SEC pricing at the time of adoption, will be drilled within five years of booking based upon management's evaluation of a number of qualitative and quantitative factors, including: estimated risk-based returns; estimated well density; cost forecasts; recent drilling, recompletion or re-stimulation results and well performance; anticipated availability of services, equipment, supplies and personnel; seasonal weather; and changes in drilling and completion techniques and technology. Our PUD reserves do not include reserves associated with non-operated properties. This process is intended to ensure that PUD reserves are only booked for locations where a final investment decision has been made by us. Our five-year development plan generally does not contemplate a uniform conversion of PUD reserves in all of its producing areas or over the five-year period covered by such plan. Our board of directors annually reviews our expenditure plan and approves the capital budget for the first year of the development plan, including with respect to any material changes made to the plan during the prior year as a result of the factors discussed below.

Following the adoption of our development plan based on information available at the time of such adoption, we review and, if the circumstances warrant, may revise the capital expenditure plan throughout the year and modify the plan after evaluating a number of factors, including: operational results; decreases in, or volatility of commodity prices; estimated risk-based returns; cost and availability of services, equipment and resources; acquisition and divestiture activity; and our current and projected financial condition and liquidity. Based on the foregoing review, we update our development plan each quarter to reflect any necessary changes, and such changes are then reviewed and approved by our senior management. Any material deviations from our capital expenditure budget and development plan are discussed with the Reserves Committee and our board of directors.

Annually and periodically as circumstances warrant, the Reserves Group conducts a detailed review on a lease-by-lease basis to assess whether potential PUD locations remain reasonably certain to be drilled on a timely basis within five years from their initial booking. If, upon completion of such review, the Reserves Group determines that any of the potential PUD locations that it identified may be unlikely to be transferred from PUDs to proved developed reserves within their anticipated development timeline, such locations are then reviewed by our senior management to determine whether we expect to have sufficient committed capital and other resources necessary to commit to the proposed development plan. If our senior management determines that a proposed PUD location is not reasonably certain to be drilled within five years of initial booking or we do not have sufficient committed capital to pursue its development, that PUD location is excluded from our subsequent estimation of our proved reserves and re-classified to non-proved reserve categories.

Costs incurred relating to the development of locations that were classified as PUDs at December 31, 2017 were approximately $308.1 million during the year ended December 31, 2018. Additionally, during 2018, we spent approximately $1,107.1 million drilling and completing other in-field wells which were not classified as proved as of December 31, 2017. Estimated future development costs relating to the development of PUDs at December 31, 2018 were projected to be approximately $498.0 million in 2019. We intend to finance such development costs with cash on hand, cash flow from operations and borrowings under our Revolving Credit Agreement. As of December 31, 2018, all of our PUD drilling locations were scheduled to be drilled within five years of their initial booking.

Additional information regarding our proved reserves can be found in the notes to our consolidated financial statements included elsewhere in this Annual Report and the audit letter relating to the proved reserve report as of December 31, 2018, which is included as an exhibit to this Annual Report.

Developed and Undeveloped Acreage

The following tables set forth information as of December 31, 2018 relating to our leasehold acreage.

	Developed Acreage (1)		Undeveloped Acreage (2)		Total Acreage	
	Gross (3)	Net (4)	Gross (3)	Net (4)	Gross (3)	Net (4)
Midland Basin	162,281	116,970	56,244	37,137	218,525	154,107
Delaware Basin	35,828	34,530	12,790	10,309	48,618	44,839
Total	198,109	151,500	69,034	47,446	267,143	198,946

(1) Developed acreage is acreage spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the applicable lease.

(2) Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

(3) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

In addition to the leasehold acreage described above, as of December 31, 2018, we held mineral rights in 34,670 acres, with an average royalty interest of 20%. These mineral rights and associated royalty interests boost net revenue interest in our applicable properties.

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. Most of the leases governing our acreage have continuous development clauses that permit us to continue to hold the acreage under such leases after the expiration of the primary term if we initiate additional development within 60 to 180 days of the expiration date, without the requirement of a lease extension payment. Thereafter, generally the leases are held with additional development every 60 to 180 days until the entire lease is held by production. The following table sets forth the gross and net undeveloped acreage, as of December 31, 2018, that will expire over the next five years unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates.

	2019		2020		2021		2022		2023	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Midland Basin	30,686	15,173	19,959	11,765	6,982	4,397	6,996	5,607	400	195
Delaware Basin	10,138	7,437	3,926	1,729	2,050	1,143	—	—	—	—
Total	40,824	22,610	23,885	13,494	9,032	5,540	6,996	5,607	400	195

As of December 31, 2018, of the total net PUD reserves associated with the expiring acreage set forth in the table above, an immaterial amount of those net PUD reserves are associated with drilling locations scheduled to be drilled after expiration of the applicable leasehold.

Drilling Results

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

	Year ended December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Horizontal:						
Development Wells [1]:						
Productive [2]	162	157	126	119	75	73
Dry holes	—	—	—	—	—	—
Exploratory Wells:						
Productive [2]	—	—	—	—	—	—
Dry holes	—	—	—	—	—	—
Vertical:						
Development Wells [1]:						
Productive [2]	2	2	2	2	4	4
Dry holes	—	—	—	—	—	—
Exploratory Wells:						
Productive [2]	—	—	—	—	—	—
Dry holes	—	—	—	—	—	—
Total:						
Productive [2]	164	159	128	121	79	77
Dry holes	—	—	—	—	—	—
	164	159	128	121	79	77

(1) Includes extension wells.

(2) Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly exploratory wells for which there is no production history.

As of December 31, 2018, in the Midland Basin, we had 16 gross (15.7 net) horizontal wells in the process of being drilled and 17 (16.3 net) horizontal wells awaiting hydraulic fracturing procedures that, in each case, are not reflected in the above table. In the Delaware Basin, we had 17 gross (16.7 net) horizontal wells in the process of being drilled and seven gross (6.8 net) horizontal wells awaiting hydraulic fracturing procedures that, in each case, are not reflected in the above table.

For additional information regarding our productive wells, see “Item 1. Business—Oil and Natural Gas Production Prices and Production Costs—Productive Wells,” which is incorporated herein by reference.

Title to Properties

As is customary in the oil and natural gas industry, when we acquire leasehold acreage, we conduct title due diligence on the subject properties but may not obtain title opinions covering the properties prior to entering into a purchase and sale agreement. At the time we determine to conduct drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects prior to commencing drilling operations. To the extent title opinions or other investigations completed after the closing of an acquisition reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry.

Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion, obtain an updated title review or opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with our use of or affect the carrying value of the properties.

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this Annual Report.

Facilities

As of December 31, 2018, we leased corporate office space in Austin, Texas at 303 Colorado Street, where our corporate headquarters is located, and at certain other locations in downtown Austin. We also leased corporate office space in Midland, Texas and owned field operation facilities in Midland and Fort Stockton, Texas. We believe that our facilities are adequate for our current operations.

During 2017, we entered into an agreement with a third party to lease commercial office space in a building being constructed at 300 Colorado Street, Austin, Texas. Upon its completion, we expect to move our corporate headquarters to this location.

Transportation and Delivery Commitments

For information regarding the transportation of our oil and natural gas, production and our contractual commitments related thereto, see “Item 1. Business—Oil and Natural Gas Production Prices and Production Costs—Transportation and Delivery Commitments,” which is incorporated herein by reference.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we are a party to ongoing legal proceedings in the ordinary course of business, including workers’ compensation claims and employment-related disputes. We do not believe the results of these proceedings, individually or in the aggregate, will have a material adverse effect on our business, financial condition, results of operations, or liquidity.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Market Information

Our Class A common stock trades on the NYSE under the symbol “PE.”

Stockholders

On February 26, 2019, we had approximately 33 holders of record of our Class A common stock. This number does not include owners for whom shares of our Class A common stock may be held in “street” name.

There is no public market for our Class B common stock. On February 26, 2019, we had 73 holders of record of our Class B common stock.

Dividends

We have never declared or paid any dividends to holders of our Class A common stock or Class B common stock. We currently intend to retain all available funds, if any, to finance our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities. In addition, our debt agreements restrict our ability to pay cash dividends to holders of our Class A common stock or Class B common stock.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table sets forth information with respect to our repurchases of shares of Class A common stock during the quarter ended December 31, 2018.

Period	Total number of shares purchased (1)	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Approximate dollar value of shares that may yet be purchased under the plans or programs
10/1/2018 - 10/31/2018	—	$ —	—	$ —
11/1/2018 - 11/30/2018	1,920	$ 23.40	—	$ —
12/1/2018 - 12/31/2018	1,730	$ 15.97	—	$ —
Total	3,650	$ 19.88	—	$ —

(1) Consists of shares of Class A common stock repurchased from employees in order for the employee to satisfy tax withholding payments related to stock-based awards that vested during the period.

Sales of Unregistered Equity Securities

We did not have any sales of unregistered equity securities during the fiscal year ended December 31, 2018.

ITEM 6. SELECTED FINANCIAL DATA

The following tables show selected historical financial data for the periods and as of the periods indicated. For the years ended December 31, 2018, 2017, 2016 and 2015, the financial statements are consolidated and for the year ended December 31, 2014 the financial statements are consolidated and combined. The following selected financial and operating data 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,				
	2018	2017	2016	2015	2014
	(in thousands, except per share data)				
REVENUES					
Oil sales	$ 1,536,244	$ 802,230	$ 387,303	$ 215,795	$ 232,554
Natural gas sales	51,231	56,571	30,928	26,582	30,642
Natural gas liquids sales	227,272	103,193	38,273	23,680	38,561
Other	11,684	5,050	1,269	417	672
Total revenues	1,826,431	967,044	457,773	266,474	302,429
OPERATING EXPENSES					
Lease operating expenses	144,292	102,169	59,293	62,913	38,071
Transportation and processing costs	32,573	—	—	—	—
Production and ad valorem taxes	108,342	59,641	27,916	17,800	18,941
Depreciation, depletion and amortization	584,857	352,247	233,766	178,281	94,297
General and administrative expenses	150,955	124,255	84,591	55,294	87,949
Exploration and abandonment costs	162,539	39,345	9,627	13,865	3,136
Impairment	—	—	—	950	—
Acquisition costs (1)	167	10,977	1,081	—	2,527
Accretion of asset retirement obligations	1,422	971	732	826	512
(Gain) loss on sale of property	(6,454)	14,332	119	34,374	2,097
Other operating expenses	19,863	10,638	9,620	10,666	765
Total operating expenses	1,198,556	714,575	426,745	374,969	248,295
OPERATING INCOME (LOSS)	627,875	252,469	31,028	(108,495)	54,134
OTHER (EXPENSE) INCOME					
Interest expense, net	(131,460)	(97,381)	(56,225)	(45,581)	(39,940)
Prepayment premium on extinguishment of debt	—	(3,891)	(36,335)	—	(5,107)
Derivative gain (loss)	50,342	(66,135)	(50,835)	60,818	83,858
Change in TRA liability	(437)	35,847	7,351	—	—
Interest income	5,464	7,936	992	28	316
Other (expense) income	(340)	783	(2,317)	(3,556)	(71)
Total other (expense) income, net	(76,431)	(122,841)	(137,369)	11,709	39,056
INCOME (LOSS) BEFORE INCOME TAXES	551,444	129,628	(106,341)	(96,786)	93,190
INCOME TAX (EXPENSE) BENEFIT	(105,475)	(5,708)	17,424	23,755	(36,468)
NET INCOME (LOSS)	445,969	123,920	(88,917)	(73,031)	56,722
LESS: NET (INCOME) LOSS ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(76,842)	(17,146)	14,735	22,547	(33,293)
NET INCOME (LOSS) ATTRIBUTABLE TO PARSLEY ENERGY, INC. STOCKHOLDERS	$ 369,127	$ 106,774	$ (74,182)	$ (50,484)	$ 23,429
Net income (loss) per common share:					
Basic	$ 1.36	$ 0.44	$ (0.46)	$ (0.45)	$ 0.65
Diluted	$ 1.35	$ 0.42	$ (0.46)	$ (0.45)	$ 0.65
Weighted average common shares outstanding:					
Basic	272,226	240,733	161,793	111,271	93,168
Diluted	272,884	296,512	161,793	111,271	93,271

(1) On April 20, 2017, we completed the Double Eagle Acquisition (as defined, and discussed further, in *Note 1—Organization and Nature of Operations* to our consolidated financial statements included elsewhere in this Annual Report) for total consideration of approximately $2.6 billion.

	Year ended December 31,				
	2018	2017	2016	2015	2014
	(in thousands, except per unit data)				
Production					
Oil (MBbls)	25,356	16,390	9,368	4,807	2,839
Natural gas (MMcf) [1]	37,365	23,326	13,463	10,339	7,245
Natural gas liquids (MBbls) [1]	8,353	4,512	2,390	1,500	1,140
Combined (MBoe)	39,937	24,792	14,002	8,031	5,186
Average daily production volume:					
Oil (Bbls/d)	69,468	44,904	25,596	13,170	7,778
Natural gas (Mcf/d)	102,370	63,907	36,794	28,326	19,849
Natural gas liquids (MBbls)	22,885	12,362	6,530	4,110	3,123
Total (Boe/d)	109,416	67,923	38,257	22,003	14,207
Average realized prices:					
Oil, without realized derivatives (per Bbls)	$ 60.59	$ 48.95	$ 41.34	$ 44.89	$ 81.91
Oil, with realized derivatives (per Bbls)	58.07	47.68	47.56	56.60	81.33
Natural gas, without realized derivatives (per Mcf)	1.37	2.43	2.30	2.57	4.23
Natural gas, with realized derivatives (per Mcf)	1.38	2.40	2.30	2.72	4.32
NGLs (per MBbls)	27.21	22.87	16.01	15.79	33.83
Average price per Boe, without realized derivatives	45.44	38.80	32.60	33.13	58.19
Average price per Boe, with realized derivatives	43.85	37.94	36.76	40.33	58.00
Expense per Boe [2]:					
Lease operating expenses	$ 3.61	$ 4.12	$ 4.23	$ 7.83	$ 7.34
Transportation and processing costs	0.82	—	—	—	—
Production and ad valorem taxes	2.71	2.41	1.99	2.22	3.65
Depreciation, depletion and amortization	14.64	14.21	16.70	22.20	18.18
General and administrative expenses	3.78	5.01	6.04	6.89	16.96
Exploration and abandonment costs	4.07	1.59	0.69	1.73	0.60
Impairment	—	—	—	0.12	—
Acquisition costs[3]	—	0.44	0.08	—	0.49
Accretion of asset retirement obligations	0.04	0.04	0.05	0.10	0.10
(Gain) loss on sale of property	(0.16)	0.58	0.01	4.28	0.40
Other operating expenses	0.50	0.43	0.69	1.33	0.15
Total operating expenses per Boe	$ 30.01	$ 28.83	$ 30.48	$ 46.70	$ 47.87
Consolidated statements of cash flows data:					
Net cash provided by (used in):					
Operating activities	$ 1,218,974	$ 690,750	$ 230,342	$ 173,429	$ 190,090
Investing activities	(1,594,036)	(3,456,860)	(1,885,366)	(427,165)	(1,247,677)
Financing activities	(15,911)	3,183,630	1,447,470	547,409	1,088,744
Proved reserves:					
Oil (MBbls)	294,446	248,531	136,536	73,877	47,617
Natural gas (MMcf)	572,038	451,703	223,605	157,175	123,645
NGLs (MBbls)	131,933	92,632	48,543	23,738	22,667
Combined (MBoe)	521,719	416,447	222,347	123,811	90,891
Consolidated balance sheet data:					
Cash, cash equivalents, restricted cash and short-term investments	$ 163,216	$ 703,472	$ 136,669	$ 344,223	$ 50,550
Total assets [3]	9,391,363	8,793,198	3,938,782	2,505,100	2,040,490
Long-term debt	2,181,667	2,179,525	1,041,324	546,832	666,257
Total equity	6,319,735	5,880,706	2,430,306	1,586,641	992,489

(1) Natural gas and NGLs sales and production volumes for the year ended December 31, 2018 reflect adjustments associated with our adoption of ASC 606, effective January 1, 2018.

(2) Average costs per Boe for the year ended December 31, 2018 reflect adjustments associated with our adoption of ASC 606, effective January 1, 2018.

(3) On April 20, 2017, we completed the Double Eagle Acquisition (as defined, and discussed further, in *Note 1—Organization and Nature of Operations* to our consolidated financial statements included elsewhere in this Annual Report) for total consideration of approximately $2.6 billion.

Non-GAAP Financial Measures

PV-10

PV-10 is a non-GAAP financial measure and generally differs from the Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net reserves. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such companies.

The following table provides a reconciliation of PV-10 to the GAAP financial measure of Standardized Measure as of December 31, 2018:

	As of December 31, 2018	
	(in millions)	
Standardized Measure	$	5,893.9
Present value of future income tax discounted at 10%		881.0
PV-10 of proved reserves	$	6,774.9

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

The following discussion and analysis should be read in conjunction with our consolidated financial statements and related notes appearing in "Item 8. Financial Statements and Supplementary Data." The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil and natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report, particularly in "Item 1A. Risk Factors" and "Cautionary Note Regarding Forward-Looking Statements," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

Overview

Parsley Energy, Inc. is an independent oil and natural gas company focused on the acquisition, development, exploration and production of unconventional oil and natural gas properties in the Permian Basin. The Permian Basin is located in west Texas and southeastern New Mexico and is characterized by high oil and liquids-rich natural gas content, multiple vertical and horizontal target horizons, extensive production histories, long-lived reserves and historically high drilling success rates. Our properties are located in two sub areas of the Permian Basin, the Midland and Delaware Basins, where, given the associated returns, we focus predominantly on horizontal development drilling.

As a holding company and the sole managing member of Parsley LLC, (i) our sole material asset consists of 280,205,293 PE Units as of December 31, 2018, (ii) we are responsible for all operational, management and administrative decisions of Parsley LLC, and (iii) we consolidate the financial and operating results of Parsley LLC and its subsidiaries.

Our Properties

The following table sets forth information as of December 31, 2018 relating to our leasehold acreage:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Midland Basin	162,281	116,970	56,244	37,137	218,525	154,107
Delaware Basin	35,828	34,530	12,790	10,309	48,618	44,839
Total	198,109	151,500	69,034	47,446	267,143	198,946

In addition to the leasehold acreage described above, as of December 31, 2018, we held mineral rights in 34,670 acres, with an average royalty interest of 20%. These mineral rights and associated royalty interests boost our net revenue interest in the applicable properties.

The majority of our identified drilling locations are located in Upton, Reagan, Midland, Howard, Martin and Glasscock Counties, Texas, in the Midland Basin, and Pecos and Reeves Counties, Texas, in the Delaware Basin.

As of December 31, 2018, we operated the following wells:

	Vertical Wells		Horizontal Wells		Total	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Midland Basin	906	723.1	364	340.8	1,270	1,063.9
Delaware Basin	13	12.5	89	84.5	102	97.0
Total	919	735.6	453	425.3	1,372	1,160.9

As of December 31, 2018, we held an interest in 1,814 gross (1,222.4 net) wells, including wells that we did not operate. As of December 31, 2018, we owned an immaterial number of productive wells related to the production of natural gas.

From the commencement of our horizontal drilling program in 2013 through December 31, 2018, we have placed on production 357 gross (326.6 net) horizontal wells in the Midland Basin and 70 gross (67.7 net) horizontal wells in the Delaware

Basin. The table below summarizes the horizontal wells placed on production during the periods indicated:

	Year Ended December 31,					
	2018		2017		2016	
Area	Gross	Net	Gross	Net	Gross	Net
Midland Basin	132	127.9	96	89.5	71	64.8
Delaware Basin	43	41.9	21	19.9	5	4.8
Total	175	169.8	117	109.4	76	69.6

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our oil and natural gas operations, including:

- production volumes;
- realized prices on the sale of oil, natural gas and NGLs, including the effect of our commodity derivative contracts;
- lease operating expenses;
- capital expenditures;
- completion activities; and
- certain unit costs.

Sources of Our Revenues

Our production revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGLs that are extracted from our natural gas during processing, and do not include the effects of derivatives. Our production revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

The following table presents the breakdown of our production revenues for the periods indicated:

	Year Ended December 31,		
	2018	2017	2016
Oil sales	84%	83%	85%
Natural gas sales	3%	6%	7%
Natural gas liquids sales	13%	11%	8%

Other revenues include fees charged by certain of our subsidiaries, Pacesetter Drilling, LLC (“Pacesetter”) and Parsley Minerals, LLC, to third parties for drilling services and surface use in the normal course of business. In addition, other revenues include saltwater disposal and gathering system income.

Production Volumes

The following table presents historical production volumes for our properties for the periods indicated:

	Year Ended December 31,		
	2018	2017	2016
Oil (MBbls)	25,356	16,390	9,368
Natural gas (MMcf)	37,365	23,326	13,463
Natural gas liquids (MBbls)	8,353	4,512	2,390
Total (MBoe)	39,937	24,792	14,002
Average net production (Boe/d)	109,416	67,923	38,257

Production Volumes Directly Impact Our Results of Operations

As reservoir pressures decline, production from a given well or formation decreases. Growth in our future production and reserves will depend on our ability to continue to add proved reserves in excess of our production. Accordingly, we plan to maintain our focus on adding reserves through the development of our properties as well as through acquisitions. Our ability to add reserves through development projects and acquisitions is dependent on many factors, including our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel and successfully identify and consummate acquisitions. Please read "Item 1A. Risk Factors—Risks Related to the Oil and Natural Gas Industry and Our Business" for a discussion of these and other risks affecting our proved reserves and production.

Realized Prices on the Sale of Oil, Natural Gas and NGLs

Historically, oil, natural gas and NGLs prices have been extremely volatile, and we expect this volatility to continue. Because our production consists primarily of oil, our production revenues are more sensitive to fluctuations in the price of oil than they are to fluctuations in the price of natural gas or NGLs.

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, we enter into derivative arrangements for a portion of our production, with an emphasis on our oil production. By removing a portion of price volatility associated with our oil production, we believe we will mitigate, but not eliminate, the potential negative effects of reductions in oil prices on our cash flow from operations for the relevant periods. See "Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk" for information regarding our exposure to market risk, including the effects of changes in commodity prices and our commodity derivative contracts.

We will continue to use commodity derivative instruments to hedge our price risk in the future. Our hedging strategy and future hedging transactions will be determined at our discretion and may be different than what we have done on a historical basis. We are not under an obligation to hedge a specific portion of our oil, natural gas or NGLs production. See *Note 4—Derivative Financial Instruments* to our consolidated financial statements included elsewhere in this Annual Report for details regarding the volumes and terms of our derivative instruments as of December 31, 2018.

We will have recognized the following cumulative losses in the line item *Gain (loss) on derivatives* on our consolidated statements of operations from net premiums paid or deferred on options that will settle during the following periods (in thousands):

Q1 2019	$	(10,715)
Q2 2019		(11,432)
Q3 2019		(13,286)
Q4 2019		(13,286)
Q1 2020		(1,643)
Q2 2020		(1,643)
	$	(52,005)

Principal Components of Our Cost Structure

Lease operating expenses. Lease operating expenses are the costs incurred in the operation of producing properties and workover costs. Expenses for direct labor, water injection and disposal, utilities, materials and supplies comprise the most significant portion of our lease operating expenses.

Transportation and processing costs. Transportation and processing costs represent third-party costs related to certain of our natural gas and NGLs marketing and processing agreements. Due to the adoption of ASC 606, we now report such costs separately. During the years ended December 31, 2017 and 2016, these costs were included in our net natural gas and NGLs sales. Refer to *Note 3—Revenue from Contracts with Customers—Impact of ASC Topic 606 Adoption* in our consolidated financial statements for additional discussion.

Production and ad valorem taxes. Production taxes are paid on produced oil and natural gas based on a percentage of revenues from production sold at fixed rates established by federal, state or local taxing authorities. We are also subject to ad valorem taxes in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and natural gas properties.

Depreciation, depletion and amortization. Depreciation, depletion and amortization ("DD&A") is the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas.

General and administrative expenses. These are costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our office facilities, costs of managing our production and development operations (including numerous software applications), audit and other fees for professional services and legal compliance.

Exploration and abandonment costs. Exploration and abandonment costs primarily include leasehold abandonment and impairment costs and geological and geophysical costs incurred**.**

Gain (loss) on derivatives. Our derivative contracts are marked-to-market each quarter with fair value gains and losses recognized currently as a gain or loss in our results of operations. The amount of future gain or loss recognized on our derivative instruments is dependent upon future oil prices, which will affect the value of the contracts. Cash flow is only impacted to the extent the actual settlements under the contracts result in making a payment to or receiving a payment from the counterparty.

Interest expense. We finance a portion of our working capital requirements and capital expenditures through offerings of fixed-rate senior unsecured notes and, in the future, could also borrow from our floating-rate Revolving Credit Agreement. As a result, we incur interest expense that is affected by our financing decisions and, in the future, may be affected by fluctuations in interest rates.

Impairment of Proved Oil and Gas Properties

Proved oil and gas properties are reviewed for impairment quarterly or when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. We estimate the expected future cash flows of our oil and gas properties and compare the undiscounted cash flows to the carrying amount of the oil and gas properties, on a field-by-field basis, to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the oil and gas properties to estimated fair value.

Given the level of commodity prices in recent years and their impact on our estimated future cash flows, we regularly review our proved oil and natural gas properties for impairment. During the years ended December 31, 2018, 2017 and 2016, we did not recognize an impairment of our proved oil and natural gas properties. At December 31, 2018, in our significant fields that comprise 100% of our carrying value, our expected undiscounted future cash flows exceeded the carrying value of our proved oil and gas properties by an average of 78% and individually by a minimum of 73%. At December 31, 2017, in our significant fields that comprise 100% of our carrying value, our expected undiscounted future cash flows exceeded the carrying value of our proved oil and gas properties by an average of 83% and individually by a minimum of 66%.

The key assumptions used to determine the undiscounted future cash flows include, but are not limited to, future commodity prices, based on five-year WTI futures price index for oil and NGLs and five-year Henry Hub futures price index for natural gas, price differentials, future production estimates, estimated future capital expenditures and estimated future operating expenses. All inputs remained relatively consistent in the undiscounted future cash flow estimate from December 31, 2017 to December 31, 2018, except commodity price estimates. Future commodity pricing for oil and NGLs is based on five-year WTI futures prices and future commodity pricing for natural gas is based on five-year Henry Hub future prices, each of which decreased from December 31, 2017 to December 31, 2018. In terms of the reduction in value of undiscounted cash flows from December 31, 2017 to December 31, 2018, the effect of the decrease in pricing has been mitigated to a certain extent by the addition of both proved developed and proved undeveloped reserves through our continued drilling and completion of previously unproved oil and natural gas properties.

As part of our year-end reserves estimation process for future periods, we expect changes in the key assumptions used, which could be significant, including updates to future pricing estimates or differentials, future production estimates to align with our anticipated five-year drilling plan and changes in our capital costs and operating expense assumptions, which we expect to decrease further as a result of sustained lower commodity prices. There is a significant degree of uncertainty with the assumptions used to estimate future undiscounted cash flows due to, but not limited to, the risk factors referred to in "Item 1A. Risk Factors" included elsewhere in this Annual Report.

Any decrease in pricing, negative change in price differentials or increase in capital or operating costs could negatively impact the estimated undiscounted cash flows related to our proved oil and natural gas properties. A decrease of 10% in estimated future pricing of oil and natural gas commodities as of December 31, 2018, however, would have not have resulted in an impairment of any proved oil and gas properties.

Factors Affecting the Comparability of Our Financial Condition and Results of Operations

Our historical financial condition and results of operations for the periods presented may not be comparable, either from period to period or going forward, for the following reasons:

Income Taxes

On December 22, 2017, Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"), was enacted by the U.S. government. The Tax Act made broad and complex changes to the U.S. corporate income tax code. Among other changes, the Tax Act: (i) reduced the U.S. federal corporate income tax rate from 35% to 21%; (ii) repealed the corporate alternative minimum tax and provided for a refund of previously accrued alternative minimum tax credits; (iii) modified the provisions relating to the limitations on deductions for executive compensation of publicly traded corporations; (iv) enacted new limitations regarding the deductibility of interest expense; and (v) imposed new limitations on the utilization of net operating losses arising in taxable years beginning after December 31, 2017.

Our operations located in Texas are subject to an entity-level tax, the Texas margin tax, at a statutory rate of up to 0.75% of revenues less operating expenses attributable to operations in Texas. We are taxed as a corporation under the Internal Revenue Code of 1986, as amended and subject to U.S. federal income tax at a statutory rate of 21% of pretax earnings and, as such, the amount of our future U.S. federal income tax will be dependent upon our future taxable income.

Capital Expenditures

Our drilling, completions and infrastructure activities are capital intensive and require us to make substantial capital expenditures, which vary from year to year. For further information about our capital expenditures, see "Item 1. Business—Overview" and "—Capital Requirements and Sources of Liquidity."

The amount and timing of our future capital expenditures is largely discretionary and within our control. We could choose to defer a portion of planned capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners.

Impact of ASC Topic 606 Adoption

We adopted ASC 606 effective January 1, 2018 using the modified retrospective approach. As a result, we changed our accounting policy for revenue recognition, which resulted in the following adjustments:

	Year Ended December 31, 2018		
	ASC 605	Adjustment	ASC 606
Production revenues (in thousands):			
Oil sales	$ 1,536,244	$ —	$ 1,536,244
Natural gas sales (1)	45,032	6,199	51,231
Natural gas liquids sales (1)	200,898	26,374	227,272
Total production revenues	1,782,174	32,573	1,814,747
Operating expenses			
Transportation and processing costs	—	32,573	32,573
Production revenues less transportation and processing costs	$ 1,782,174	$ —	$ 1,782,174
Net income attributable to Parsley Energy, Inc. stockholders (in thousands)	$ 369,127	$ —	$ 369,127
Production:			
Oil (MBbls)	25,356	—	25,356
Natural gas (MMcf) (1)	33,492	3,873	37,365
Natural gas liquids (MBbls) (1)	7,356	997	8,353
Total (MBoe)	38,293	1,644	39,937
Average daily production volume:			
Oil (Bbls)	69,468	—	69,468
Natural gas (Mcf)	91,759	10,611	102,370
Natural gas liquids (Bbls)	20,153	2,732	22,885
Total (Boe)	104,912	4,504	109,416
Certain unit costs (per Boe) (2):			
Lease operating expenses	$ 3.77	$ (0.16)	$ 3.61
Transportation and processing costs	$ —	$ 0.82	$ 0.82
Production and ad valorem taxes	$ 2.83	$ (0.12)	$ 2.71
Depreciation, depletion and amortization	$ 15.27	$ (0.63)	$ 14.64
General and administrative expenses	$ 3.94	$ (0.16)	$ 3.78

(1) Natural gas and NGLs sales and production volumes for the year ended December 31, 2018 reflect adjustments associated with our adoption of ASC 606, effective January 1, 2018.

(2) Average costs per Boe for the year ended December 31, 2018 reflect adjustments associated with our adoption of ASC 606, effective January 1, 2018.

Changes to natural gas and NGLs sales were made in accordance with the control model defined in ASC 606. Under the new control model, we are required to identify and separately analyze each contract associated with revenues to determine the appropriate accounting application. We considered various indicators for contracts and the weighting of their relevance to determine when control transferred to the customer (such as whether raw gas is sold at the receipt point or residue gas and NGLs are sold at the tailgate of the gas processing plants). Based on this analysis, we concluded that the presence of product redelivery and take-in-kind rights, if substantive, are determinative indicators of control transferring at the tailgate if there is intent at contract inception. Additionally, we consider risk of loss an important indicator of when control transfers, which is comprised of risks associated with loss of product, exposure to product mix and recoveries and exposure to index prices versus actual prices. We also concluded that title, custody and acceptance are not determinative indicators of control, as such factors may be present in the case of a sale or the performance of a service.

As a result of this analysis, we modified our accounting and presentation of natural gas and NGLs sales, and transportation and processing costs, under certain marketing agreements. This is due to the conclusion that we represent the principal and the ultimate third party is our customer, which implies that we maintain control of the product through the tailgate of gas processing plants in certain natural gas processing and marketing agreements with certain midstream entities in accordance with the control model in ASC 606. This is a change from previous conclusions we reached for these agreements when utilizing the principal versus agent indicators under ASC Topic 605, *Revenue Recognition*, where we acted as the agent and the midstream processing company acted as our customer. As a result, our presentation of revenues and expenses for these agreements has been modified. Revenues related to these agreements are now presented on a gross basis for amounts expected to be received from third-party customers through the marketing process. Transportation and processing costs related to these agreements, incurred prior to the transfer of control to the customer at the tailgate of the natural gas processing facilities, are now presented as *Transportation and processing costs* on our consolidated statements of operations. Additionally, all references to production and per Boe unit costs reflect this adoption, which has the effect of increasing certain natural gas and NGLs volumes and revenues, offset by a corresponding transportation and processing expense, such that there is no change to reported net income. Refer to *Note 3—Revenue from Contracts with Customers—Impact of ASC Topic 606 Adoption* in our consolidated financial statements for additional discussion.

All comparisons to prior period sales, expenses, production volumes and unit costs reflect the changes in reporting methodology for the year ended December 31, 2018. To provide additional insight, in the above tables, we have quantified the impact of the adoption of ASC 606 during the year ended December 31, 2018.

Results of Operations

Revenues

The following table provides the components of our production revenues for the periods indicated, as well as each period's respective average prices and production volumes:

	Year Ended December 31,		
	2018	2017	2016
Production revenues (in thousands):			
Oil sales	$ 1,536,244	$ 802,230	$ 387,303
Natural gas sales (1)	51,231	56,571	30,928
Natural gas liquids sales (1)	227,272	103,193	38,273
Total revenues	$ 1,814,747	$ 961,994	$ 456,504
Average realized prices (2):			
Oil, without realized derivatives (per Bbls)	$ 60.59	$ 48.95	$ 41.34
Oil, with realized derivatives (per Bbls)	58.07	47.68	47.56
Natural gas, without realized derivatives (per Mcf)	1.37	2.43	2.30
Natural gas, with realized derivatives (per Mcf)	1.38	2.40	2.30
Natural gas liquids (per Bbls)	27.21	22.87	16.01
Average price per Boe, without realized derivatives	45.44	38.80	32.60
Average price per Boe, with realized derivatives	43.85	37.94	36.76
Production:			
Oil (MBbls)	25,356	16,390	9,368
Natural gas (MMcf) (1)	37,365	23,326	13,463
Natural gas liquids (MBbls) (1)	8,353	4,512	2,390
Total (MBoe)	39,937	24,792	14,002
Average daily production volume:			
Oil (Bbls)	69,468	44,904	25,596
Natural gas (Mcf)	102,370	63,907	36,784
Natural gas liquids (Bbls)	22,885	12,362	6,530
Total (Boe)	109,416	67,923	38,257

(1) Natural gas and NGLs sales and production volumes for the year ended December 31, 2018 reflect adjustments associated with our adoption of ASC 606, effective January 1, 2018.

(2) Average prices shown in the table reflect prices both before and after the effects of our realized commodity hedging transactions. Our calculation of such effects includes both realized gains and losses on cash settlements for commodity derivative transactions and premiums paid or received on options that settled during the period.

The table below shows, for the periods indicated, the relationship between our average realized oil price as a percentage of the average NYMEX oil price, the relationship between our average realized natural gas price as a percentage of the average NYMEX gas price, and the relationship between our average realized NGLs price as a percentage of the average NYMEX oil price. Management uses the realized price to NYMEX margin analysis to analyze trends in our oil, natural gas and NGLs revenues. Realized oil, natural gas and NGLs prices are the actual prices realized at the wellhead adjusted for quality, transportation fees and costs, differentials, marketing premiums or deductions and other factors that affect the price received at the wellhead.

	Year Ended December 31,		
	2018	2017	2016
Average realized oil price ($/Bbl)	$ 60.59	$ 48.95	$ 41.34
Average NYMEX ($/Bbl)	64.80	50.80	43.40
Differential to NYMEX	(4.21)	(1.85)	(2.06)
Average realized oil price as a percentage of average NYMEX oil price	94%	96%	95%
Average realized natural gas price ($/Mcf)	$ 1.37	$ 2.43	$ 2.30
Average NYMEX ($/Mcf)	3.07	3.02	2.55
Differential to NYMEX	(1.70)	(0.59)	(0.25)
Average realized natural gas price as a percentage of average NYMEX gas price	45%	80%	90%
Average realized NGLs price ($/Bbl)	$ 27.21	$ 22.87	$ 16.01
Average NYMEX ($/Bbl)	64.80	50.80	43.40
Differential to NYMEX	(37.59)	(27.93)	(27.39)
Average realized NGLs price as a percentage of average NYMEX oil price	42%	45%	37%

Oil, natural gas and NGLs revenues. Our oil, natural gas and NGLs revenues totaled $1,814.7 million, $962.0 million and $456.5 million during the years ended December 31, 2018, 2017 and 2016, respectively.

Our oil, natural gas and NGLs revenues increased by $852.8 million, or 89%, to $1,814.7 million for the year ended December 31, 2018 from $962.0 million for the year ended December 31, 2017.

As shown in the following tables, from the year ended December 31, 2017 to the year ended December 31, 2018, the net dollar effect of the increase in oil and NGLs prices and decrease in natural gas prices was $292.0 million and the net dollar effect of the increase in production volumes of oil, natural gas and NGLs was $560.7 million.

	Change in prices	2018 Production volumes	Total net dollar effect of change
Effect of change in price:		(in thousands)	(in thousands)
Oil (per Bbls)	$ 11.64	25,356	$ 295,161
Natural gas (per Mcf)	(1.06)	37,365	(39,387)
Natural gas liquids (per Bbls)	4.34	8,353	36,232
Total revenues due to change in price			$ 292,006

	Change in production volumes	2017 Average prices	Total net dollar effect of change
Effect of change in production volumes:	(in thousands)		(in thousands)
Oil (MBbls)	8,966	$ 48.95	$ 438,853
Natural gas (MMcf)	14,039	2.43	34,047
Natural gas liquids (MBbls)	3,841	22.87	87,847
Total revenues due to change in production volumes			$ 560,747

Our oil, natural gas and NGLs revenues increased by $505.5 million, or 111%, to $962.0 million for the year ended December 31, 2017 from $456.5 million for the year ended December 31, 2016.

As shown in the following tables, from the year ended December 31, 2016 to the year ended December 31, 2017, the net dollar effect of the increase in oil, natural gas prices and NGLs prices was $158.5 million and the net dollar effect of the increase in production volumes of oil, natural gas and NGLs was approximately $347.0 million.

	Change in prices	2017 Production volumes	Total net dollar effect of change
Effect of change in price:		(in thousands)	(in thousands)
Oil (per Bbls)	$ 7.61	16,390	$ 124,615
Natural gas (per MMcf)	0.13	23,326	2,983
Natural gas liquids (per Bbls)	6.86	4,512	30,939
Total revenues due to change in price			$ 158,537

	Change in production volumes	2016 Average prices	Total net dollar effect of change
Effect of change in production volumes:	(in thousands)		(in thousands)
Oil (MBbls)	7,022	$ 41.34	$ 290,312
Natural gas (MMcf)	9,863	2.30	22,660
Natural gas liquids (MBbls)	2,122	16.01	33,981
Total revenues due to change in production volumes			$ 346,953

Operating expenses

The following table summarizes our operating expenses for the periods indicated:

	Year ended December 31,		
	2018	2017	2016
Operating expenses (in thousands):			
Lease operating expenses	$ 144,292	$ 102,169	$ 59,293
Transportation and processing costs	32,573	—	—
Production and ad valorem taxes	108,342	59,641	27,916
Depreciation, depletion and amortization	584,857	352,247	233,766
General and administrative expenses (1)	150,955	124,255	84,591
Exploration and abandonment costs	162,539	39,345	9,627
Acquisition costs	167	10,977	1,081
Accretion of asset retirement obligations	1,422	971	732
(Gain) loss on sale of property	(6,454)	14,332	119
Other operating expenses	19,863	10,638	9,620
Total operating expenses	$ 1,198,556	$ 714,575	$ 426,745
Operating expenses per Boe (2):			
Lease operating expenses	$ 3.61	$ 4.12	$ 4.23
Transportation and processing costs	0.82	—	—
Production and ad valorem taxes	2.71	2.41	1.99
Depreciation, depletion and amortization	14.64	14.21	16.70
General and administrative expenses	3.78	5.01	6.04
Exploration and abandonment costs	4.07	1.59	0.69
Acquisition costs	—	0.44	0.08
Accretion of asset retirement obligations	0.04	0.04	0.05
(Gain) loss on sale of property	(0.16)	0.58	0.01
Other operating expenses	0.50	0.43	0.69
Total operating expenses per Boe	$ 30.01	$ 28.83	$ 30.48

(1) General and administrative expenses include stock-based compensation expense of $19.9 million, $19.6 million and $12.9 million for the years ended December 31, 2018, 2017 and 2016, respectively.

(2) All unit costs for the year ended December 31, 2018 reflect the adoption of ASC 606, which had the effect of increasing certain natural gas and NGLs volumes. In turn, the increase in natural gas and NGLs volumes effectively decreased unit costs by approximately 4%.

Lease operating expenses. Lease operating expenses increased 41% to $144.3 million during the year ended December 31, 2018 from $102.2 million during the year ended December 31, 2017. The increase is primarily due to the increase in the number of our operated and non-operated wells during 2018. On a per Boe basis, lease operating expenses decreased $0.51 per Boe, or 12%, to $3.61 per Boe for the year ended December 31, 2018 from $4.12 per Boe for the year ended December 31, 2017. The decrease in lease operating expense per Boe is also primarily attributable to a 61% increase in production during the same period.

Lease operating expenses increased 72% to $102.2 million during the year ended December 31, 2017 from $59.3 million during the year ended December 31, 2016. The increase is primarily due to the increase in the number of our operated and non-operated wells during 2017. On a per Boe basis, lease operating expenses decreased $0.11 per Boe, or 3%, to $4.12 per Boe for the year ended December 31, 2017 from $4.23 per Boe for the year ended December 31, 2016. The decrease in lease operating expenses per Boe is partially attributable to a greater portion of our production coming from horizontal wells. The decrease in lease operating expense per Boe is also partially attributable to a 77% increase in production during the same period.

Transportation and processing costs. Transportation and processing costs were $32.6 million and $0.82 on a per Boe basis for the year ended December 31, 2018. Transportation and processing costs represent third-party costs related to certain of our natural gas and NGLs marketing and processing agreements. Due to the adoption of ASC 606, we now report such costs separately. During the years ended December 31, 2017 and 2016, these costs were included in our net natural gas and NGLs sales. Refer to *Note 3—Revenue from Contracts with Customers—Impact of ASC Topic 606 Adoption* in our consolidated financial statements for additional discussion.

Production and ad valorem taxes. Production and ad valorem taxes increased 82% to $108.3 million during the year ended December 31, 2018 from $59.6 million during the year ended December 31, 2017. On a per Boe basis, production and ad valorem taxes increased 12% to $2.71 per Boe for the year ended December 31, 2018 from $2.41 per Boe for the year ended December 31, 2017. Overall, production taxes increased by approximately $40.7 million, reflecting increased production volumes, and ad valorem taxes increased $8.0 million, reflecting increased property assessments.

Production and ad valorem taxes increased 114% to $59.6 million during the year ended December 31, 2017 from $27.9 million during the year ended December 31, 2016. On a per Boe basis, production and ad valorem taxes increased 21% to $2.41 per Boe for the year ended December 31, 2017 from $1.99 per Boe for the year ended December 31, 2016. Overall, production taxes increased by approximately $26.0 million, reflecting increased production volumes, and ad valorem taxes increased $5.7 million, reflecting increased property assessments.

Depreciation, depletion and amortization. DD&A expense increased 66% to $584.9 million for the year ended December 31, 2018 from $352.2 million for the year ended December 31, 2017. On a per Boe basis, DD&A increased 3% to $14.64 for the year ended December 31, 2018 from $14.21 per Boe for the year ended December 31, 2017. These increases are largely attributable to acquisitions and development activity that resulted in a $2,166.6 million increase in costs subject to depletion and a 61% increase in production during the year ended December 31, 2018. These increases were partially offset by a 25% increase in total proved reserves as of December 31, 2018, as compared to December 31, 2017.

DD&A expense increased 51% to $352.2 million for the year ended December 31, 2017 from $233.8 million for the year ended December 31, 2016. On a per Boe basis, DD&A decreased 15% to $14.21 for the year ended December 31, 2017 from $16.70 per Boe for the year ended December 31, 2016, as a result of increased production. The increase in DD&A expense is due to an increase in proved capitalized costs primarily related to development costs incurred during the year ended December 31, 2017.

General and administrative expenses. General and administrative expenses increased 21% to $151.0 million during the year ended December 31, 2018 from $124.3 million during the year ended December 31, 2017, primarily as a function of personnel growth associated with increased development activity on an expanded asset base. On a per Boe basis, general and administrative expenses decreased 25% to $3.78 per Boe for the year ended December 31, 2018 from $5.01 per Boe for the year ended December 31, 2017, which primarily relates to the 61% increase in total production volume.

General and administrative expenses increased 47% to $124.3 million during the year ended December 31, 2017 from $84.6 million during the year ended December 31, 2016, primarily as a function of personnel growth associated with increased development activity on an expanded asset base. On a per Boe basis, general and administrative expenses decreased 17% to $5.01 per Boe for the year ended December 31, 2017 from $6.04 per Boe for the year ended December 31, 2016, which primarily relates to the 77% increase in total production volume.

Exploration and abandonment costs. The following table provides a breakdown of exploration and abandonment costs incurred during the periods indicated (in thousands):

	Year Ended December 31,		
	2018	**2017**	**2016**
Leasehold abandonments and impairments	$ 160,834	$ 32,872	$ 6,063
Geological and geophysical costs	1,479	5,429	3,015
Unproved leasehold amortization	226	1,044	549
Total exploration and abandonment costs	$ 162,539	$ 39,345	$ 9,627

During the years ended December 31, 2018, 2017 and 2016, we recognized total leasehold abandonment and impairment charges of approximately $160.8 million, $32.9 million and $6.1 million, respectively, which primarily relate to expired acreage or expiring acreage that is probable of reverting to the lessor. Consistent with our commitment to capital discipline and in response to recent commodity price trends, we intend to reduce our 2019 capital leasing and acquisition spending. As a result, in the fourth quarter of 2018, we recorded non-cash leasehold impairment expense of $127.0 million relating to acreage expiring in future periods because we have no current plans to drill or extend the applicable leases prior to their expiration. For the years ended December 31, 2018, 2017 and 2016 we recognized non-cash leasehold abandonment expense of $33.8 million, $32.9 million and $6.1 million due to leases expiring during those periods for which previous efforts to sell or trade these leases were unsuccessful. In determining the amount of non-cash abandonment charges for such periods, we considered the application of the factors described under "—Critical Accounting Policies and Estimates—Impairment of Unproved Oil and Natural Gas Properties."

During the years ended December 31, 2018, 2017 and 2016, we incurred geological and geophysical expenses of approximately $1.5 million, $5.4 million and $3.0 million, respectively. Our geological and geophysical expenses consist of the costs of acquiring and processing seismic data, geophysical data and core analysis, primarily relating to increased geoscientific analysis of our acreage.

We recognized unproved leasehold amortization expense during the years ended December 31, 2018, 2017 and 2016 of $0.2 million, $1.0 million and $0.5 million, respectively, which relates to amortization of unproved leasehold costs.

Impairment. We regularly review our long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting. There were no costs incurred related to impairment of proved oil and natural gas properties during the years ended December 31, 2018, 2017 or 2016.

Acquisition Costs. During the years ended December 31, 2018, 2017 and 2016, we incurred $0.2 million, $11.0 million and $1.1 million, respectively, of acquisition costs, which include legal and other due diligence fees associated with the acquisitions described in *Note 6—Acquisitions of Oil and Natural Gas Properties* to our consolidated financial statements included elsewhere in this Annual Report.

(Gain) loss on sale of property. During the years ended December 31, 2018, 2017 and 2016, we incurred a gain of $6.5 million, and losses of $14.3 million and $0.1 million, respectively, as a result of the sale of property.

Other operating expenses. During the years ended December 31, 2018, 2017 and 2016, other operating expenses primarily included costs associated with our majority-owned subsidiary, Pacesetter, idle charges and bad debt expense. Costs incurred during the normal course of business of our majority-owned subsidiary, Pacesetter, were $6.9 million, $9.6 million and $5.3 million, respectively. As discussed in *Note 7—Sales of Oil and Natural Gas Properties* to our consolidated financial statements included elsewhere in this Annual Report, during the year ended December 31, 2018, Pacesetter completed the sale of all of its physical assets. We also incurred idle charges, which constitute other operating expenses, of $8.8 million, $1.1 million and $4.3 million, respectively for the years ended December 31, 2018, 2017 and 2016. The idle charges are a result of nonrecurring costs incurred associated with temporarily idled contracted assets and services. In addition, during the year ended December 31, 2018 we recorded bad debt expense of $2.8 million as discussed in *Note 2—Summary of Significant Policies*. There were no such costs incurred during the years ended December 31, 2017 or 2016.

Other income (expense)

The following table summarizes our other income and expenses for the periods indicated (in thousands):

	Year ended December 31,		
	2018	2017	2016
Other income (expense):			
Interest expense, net	$ (131,460)	$ (97,381)	$ (56,225)
Loss on early extinguishment of debt	—	(3,891)	(36,335)
Gain (loss) on derivatives	50,342	(66,135)	(50,835)
Change in TRA liability	(437)	35,847	7,351
Interest income	5,464	7,936	992
Other (expense) income	(340)	783	(2,317)
Total other expense, net	$ (76,431)	$ (122,841)	$ (137,369)

Interest expense. Interest expense increased 35% to $131.5 million in the year ended December 31, 2018 from $97.4 million during the year ended December 31, 2017, primarily due to interest under our 5.250% senior unsecured notes due 2025 (the "New 2025 Notes") and 5.625% senior unsecured notes due 2027 (the "2027 Notes") issued in 2017.

Interest expense increased 73% to $97.4 million in the year ended December 31, 2017 from $56.2 million during the year ended December 31, 2016, primarily due to interest under our 6.250% senior unsecured notes due 2024 (the "2024 Notes") and 5.375% senior unsecured notes due 2025 (the "2025 Notes").

Loss on early extinguishment of debt. We recorded a $3.9 million loss on early extinguishment of debt during the year ended December 31, 2017 due to the redemption of our previously outstanding 7.500% senior unsecured notes due 2022 (the "2022 Notes"). During December 2016, we incurred a $36.3 million charge related to a prepayment penalty on our then outstanding 2022 Notes. No similar expenses were incurred during the year ended December 31, 2018.

Gain (loss) on derivatives. Gain on derivatives increased $116.5 million to a gain of $50.3 million during the year ended December 31, 2018 as compared to a $66.1 million loss during the year ended December 31, 2017, as lower commodity prices increased the value of our derivative portfolio.

Loss on derivatives increased $15.3 million to a loss of $66.1 million during the year ended December 31, 2017 as compared to a $50.8 million loss during the year ended December 31, 2016, as higher commodity prices reduced the value of our derivative portfolio.

Change in TRA liability. We recorded a $0.4 million expense during the year ended December 31, 2018, associated with an increase in the TRA liability primarily resulting from the reversal of the valuation allowance recorded during 2017. We recorded income of $35.8 million during the year ended December 31, 2017 associated with a net decrease in the TRA liability associated with a write off of deferred tax assets associated with the TRA. This write off primarily resulted from the change in corporate tax rates from 35% to 21% offset by a decrease in the valuation allowance recorded during 2016. We recorded a $7.4 million deferred tax asset valuation allowance associated with a write off of deferred tax assets associated with the TRA during the year ended December 31, 2016.

Interest income. Interest income decreased $2.5 million to $5.5 million during the year ended December 31, 2018 as compared to $7.9 million during the year ended December 31, 2017, as a result of decreased dividend and interest income offset by increased amortization, which relates to our held to maturity securities, as discussed in *Note 14—Disclosures about Fair Value of Financial Instruments* to our consolidated financial statements included elsewhere in this Annual Report.

Interest income increased $6.9 million to $7.9 million during the year ended December 31, 2017 as compared to $1.0 million during the year ended December 31, 2016, which is a function of interest income received on larger investments in commercial paper and money market funds, which are included in cash and cash equivalents and short-term investments on our consolidated balance sheet.

Other income (expense). Other income (expense) decreased $1.1 million to expense of $0.3 million during the year ended December 31, 2018 as compared to income of $0.8 million during the year ended December 31, 2017. The decrease is attributable to a $0.7 million decrease in geological and geophysical license fee income and a $0.5 million decrease in fair value adjustments associated with money market accounts, and was offset by increases in other miscellaneous items.

Other income (expense) increased $3.1 million to income of $0.8 million during the year ended December 31, 2017 as compared to an expense of $2.3 million during the year ended December 31, 2016. The increase is attributable a $1.4 million increase in income from our equity investment in Spraberry Production Services LLC, a $0.8 million increase in geological and geophysical license fee income and a $0.4 million increase in fair value adjustments associated with money market accounts, which was offset by a current period downward fair market value adjustment of $1.1 million. Additionally, during the year ended December 31, 2016, we recorded expense of $1.6 million associated with the sale or auction of certain inventory items.

Income Tax Expense

For the years ended December 31, 2018, 2017 and 2016, our operations were taxed at a combined U.S. federal and state effective tax rate of 19.1%, 4.4% and 16.4%, respectively. During the year ended December 31, 2018, we recognized an income tax expense of $105.5 million, an increase of $99.8 million, as compared to the income tax expense of $5.7 million we recognized during the year ended December 31, 2017. These changes were attributable to the changes in our results of operations, discussed above, as well as the impact of net income attributable to noncontrolling ownership interests, the impact of state income taxes, and the partial reversal of a valuation allowance that was recorded in 2017 described in *Note 11—Income Taxes* to our consolidated financial statements included elsewhere in this Annual Report. During the year ended December 31, 2017, we recognized an income tax expense of $5.7 million, an increase of $23.1 million, as compared to the income tax benefit of $17.4 million we recognized during the year ended December 31, 2016. These changes were attributable to the changes in our results of operations, discussed above, as well as the impact of net income attributable to noncontrolling ownership interests, the impact of state income taxes, reduction in TRA liability due the change in corporate tax rates from 35% to 21%, and the partial reversal of a valuation allowance that was recorded in 2016 described in *Note 11—Income Taxes* to our consolidated financial statements included elsewhere in this Annual Report.

Capital Requirements and Sources of Liquidity

The following table sets forth our capital expenditures for drilling, completions and infrastructure for the periods indicated (in thousands):

	Year Ended December 31,	
	2018	2017
Capital expenditures	$ 1,762,218	$ 1,207,401

Our 2019 budget for capital development expenditures is approximately $1,350.0 million to $1,550.0 million, approximately 85% of which is expected to be used for drilling and completions and approximately 15% of which is expected to be used for infrastructure and other expenditures. We expect approximately 30% to 35% of the total budget to be associated with drilling and completions for proved undeveloped reserves as of December 31, 2018. Our capital budget excludes any amounts that may be paid for acquisitions. For the years ended December 31, 2018 and 2017, our aggregate drilling and completion expenditures were $1,510.1 million and $1,049.6 million, respectively, and our infrastructure and other expenditures were $252.1 million and $157.8 million, respectively, for totals of $1,762.2 million and $1,207.4 million, respectively. Of these totals, $308.1 million and $65.1 million were associated with drilling, completion and facility buildout for proved undeveloped reserves for the years ended December 31, 2017 and 2016, respectively. The amount and timing of 2019 capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned 2019 capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners.

Based upon current oil and natural gas price expectations for fiscal year 2019, we believe that our cash on hand, cash flow from operations and borrowings under our Revolving Credit Agreement will be sufficient to fund our operations through 2019. As of December 31, 2018, our liquidity is as follows (in millions):

Cash and cash equivalents	$	163.2
Revolving Credit Agreement Availability		991.3
Liquidity	$	1,154.5

Future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and the significant capital expenditures required to more fully develop our properties. For example, we expect a portion of our future capital expenditures to be financed with cash flows from operations derived from wells drilled in drilling locations not associated with proved reserves on our December 31, 2018 reserve report. The failure to achieve anticipated production and cash flows from operations from such wells could result in a reduction in future capital spending. Further, our capital expenditure budget for the year ended December 31, 2019 does not allocate any amounts for acquisitions of oil and natural gas properties. In the event we make additional acquisitions and the amount of capital required is greater than the amount we have available for acquisitions at that time, we could be required to reduce the expected level of capital expenditures and/or seek additional capital. If we require additional capital for that or other reasons, we may seek such capital through traditional reserve base borrowings, joint venture partnerships, production payment financings, asset sales, offerings of debt or equity securities or other means. We cannot assure you that needed capital will be available on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our current drilling programs, which could result in a loss of acreage through lease expirations. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to replace our reserves. We may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for other debt or equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Cash Flows

The following table summarizes our cash flows for the periods indicated (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Net cash provided by operating activities	$ 1,218,974	$ 690,750	$ 230,342
Net cash used in investing activities	(1,594,036)	(3,456,860)	(1,885,366)
Net cash (used in) provided by financing activities	(15,911)	3,183,630	1,447,470

Cash flows provided by operating activities. Net cash provided by operating activities was approximately $1,219.0 million, $690.8 million and $230.3 million during the years ended December 31, 2018, 2017 and 2016, respectively.

Net cash provided by operating activities increased $528.2 million to $1,219.0 million during the year ended December 31, 2018 from $690.8 million during the year ended December 31, 2017, primarily due to a $859.4 million increase in total revenues associated with increased production volumes and an overall increase in average realized oil and NGLs prices, offset by an increase of $148.3 million in increase in cash based operating expenses, including lease operating expenses, production and ad valorem taxes and cash general and administrative expenses.

Net cash provided by operating activities increased $460.4 million to $690.8 million during the year ended December 31, 2017 from $230.3 million during the year ended December 31, 2016, primarily due to a $509.3 million increase in total revenues, offset by a $387.6 million increase in cash based operating expenses, including lease operating expenses, production and ad valorem taxes, cash general and administrative expenses and acquisition costs.

Cash flows used in investing activities. Net cash used in investing activities was approximately $1.6 billion, $3.5 billion and $1.9 billion during the years ended December 31, 2018, 2017 and 2016, respectively.

The reduction in the amount of cash used in investing activities during the year ended December 31, 2018 as compared to the year ended December 31, 2017 was due primarily to the $2,055.1 million decrease in acquisition costs, offset by the $698.4 million increase in development costs related to our oil and natural gas properties during the year ended December 31, 2018.

The increased amount of cash used in investing activities during the year ended December 31, 2017 as compared to the year ended December 31, 2016 was due primarily to the $845.9 million increase in acquisition costs and the $583.5 million increase in development costs related to our oil and natural gas properties during the year ended December 31, 2017.

Cash flows (used in) provided by financing activities. Net cash used in financing activities was approximately $15.9 million and net cash provided by financing activities was $3.2 billion and $1.4 billion during the years ended December 31, 2018, 2017 and 2016, respectively.

Net cash provided by financing activities decreased by $3.2 billion during the year ended December 31, 2018, as a result of the Company not completing any debt or equity issuances in the period. During the year ended December 31, 2018, we had payments on long-term debt of $2.9 million and $11.0 million related to the vesting of time-based restricted stock units, shares of time-based restricted stock and shares of performance based restricted stock, respectively. In addition, following the sale by Pacesetter of all its physical assets, Pacesetter paid an owner distribution of $2.0 million, as discussed in *Note 9—Equity—Noncontrolling Interest* to our consolidated financial statements included elsewhere in this Annual Report.

Net cash provided by financing activities increased during the year ended December 31, 2016, primarily due to increased debt and equity related activity. During the year ended December 31, 2017, we received net proceeds from equity offerings of $2.1 billion and net proceeds from debt offerings of $1.1 billion, which was offset by payments on long-term debt of $74.8 million, excluding accrued and unpaid interest.

Capital Sources

Revolving Credit Agreement. See *Note 8—Debt* to our consolidated financial statements included elsewhere in this Annual Report for a description of the Revolving Credit Agreement.

6.250% Senior Unsecured Notes due 2024. See *Note 8—Debt* to our consolidated financial statements included elsewhere in this Annual Report for information regarding the 2024 Notes.

5.375% Senior Unsecured Notes due 2025. See *Note 8—Debt* to our consolidated financial statements included elsewhere in this Annual Report for information regarding the 2025 Notes.

5.250% Senior Unsecured Notes due 2025. See *Note 8—Debt* to our consolidated financial statements included elsewhere in this Annual Report for information regarding the New 2025 Notes.

5.625% Senior Unsecured Notes due 2027. See *Note 8—Debt* to our consolidated financial statements included elsewhere in this Annual Report for information regarding the 2027 Notes.

Derivative Activity. We plan to continue our practice of entering into hedging arrangements to (i) reduce the impact of commodity price volatility on our cash flow from operations and (ii) support our annual capital budgeting and expenditure plans. Under this strategy, we intend to continue our historical practice of entering into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering a portion of our projected oil production.

Working Capital. Our working capital totaled ($108.2) million, $307.4 million and $259.8 million at December 31, 2018, 2017 and 2016, respectively. Our collection of receivables has historically been timely and losses associated with uncollectible receivables have historically not been significant. Our cash and cash equivalents and short-term investments totaled $163.2 million, $703.5 million and $136.7 million at December 31, 2018, 2017 and 2016, respectively. The $540.3 million decrease in cash and cash equivalents and short-term investments is attributable to the development of our oil and natural gas properties as well as the $137.0 million in acquisitions described in *Note 6—Acquisition of Oil and Natural Gas Properties* to our consolidated financial statements included elsewhere in this Annual Report. Due to the amounts that we accrue related to our drilling program, we may incur working capital deficits in the future. We believe that our cash on hand, cash flow from operations, availability under our Revolving Credit Agreement. We expect that our pace of development, production volumes, commodity prices and differentials to NYMEX prices for our oil and natural gas production will be the largest variables affecting our working capital.

Contractual Obligations

Our contractual obligations include long-term debt, cash interest expense on debt, operating lease obligations, drilling commitments, derivative liabilities and other obligations. See "Item 1. Business—Transportation and Delivery Commitments" and *Note 13—Commitments and Contingencies* to our consolidated financial statements included elsewhere in this Annual Report for a description of certain of our firm transportation and crude oil sales agreements.

We had the following contractual obligations at December 31, 2018:

	Payments Due by Period For the Year Ended December 31,						
	2019	2020	2021	2022	2023	Thereafter	Total
Revolving Credit Agreement (1)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Notes (2)	—	—	—	—	—	2,200,000	2,200,000
Interest (3)	122,421	122,421	122,421	122,421	122,421	234,284	846,389
Capital lease obligations (4)	2,413	1,288	436	51	14	—	4,202
Operating lease obligations (5)	19,258	11,649	16,750	22,473	21,822	148,508	240,460
Drilling commitments (6)	52,740	27,754	9,908	—	—	—	90,402
Asset retirement obligations (7)	2,134	792	853	701	799	21,605	26,884
Firm transportation and crude oil sales agreements (8)	28,937	27,274	27,931	28,662	29,401	45,414	187,619
Derivative obligations (9)	51,099	3,285	—	—	—	—	54,384
Total (10)	$ 279,002	$ 194,463	$ 178,299	$ 174,308	$ 174,457	$2,649,811	$3,650,340

(1) Does not include future commitment fees, amortization of deferred financing costs, interest expense or other fees related to the Revolving Credit Agreement because obligations thereunder are floating rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments or future interest rates to be charged.

(2) Includes principal only.

(3) Includes fixed rate interest on the 2024 Notes, the 2025 Notes, the New 2025 Notes and the 2027 Notes.

(4) We periodically enter into capital lease agreements payable in connection with the lease of vehicles for operations and field personnel.

(5) We lease equipment and office facilities under non-cancellable operating leases.

(6) We periodically enter into contractual arrangements under which we are committed to expend funds to drill wells in the future, including agreements to secure drilling rig services, which require us to make future minimum payments to the rig operators. We record drilling commitments in the periods in which well capital is incurred or rig services are provided.

(7) Amounts represent estimates of future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment.

(8) Amounts equal the total deficiency fees payable if the Company is unable to meet all of its contractual delivery commitments under its long-term firm transportation and crude oil sales agreements. However, in the event the Company is unable to meet any portion of such contractual delivery commitments, the Company may purchase commodities in the market at then-current market prices to satisfy such commitments, in which case such deficiency fees would not be payable.

(9) We enter into derivative agreements to hedge future production. We have deferred payment of the premium for certain agreements until the period of settlement.

(10) These amounts do not include any contractual obligations incurred after December 31, 2018.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in the preparation of our consolidated financial statements. See below for an expanded discussion of our significant accounting policies and estimates made by management.

Successful Efforts Method of Accounting

Proved Oil and Natural Gas Properties

Oil and natural gas exploration, development and production activities are accounted for in accordance with the successful efforts method of accounting. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized.

As exploration and development work progresses and the reserves on these properties are proven, capitalized costs attributed to the properties and mineral interests are subject to DD&A. Depletion of capitalized costs is provided using the units-of-production method based on proved oil and gas reserves related to the associated reservoir.

Exploration and abandonment costs, other than exploration drilling costs, are charged to expense as incurred. These costs include seismic expenditures and other geological and geophysical costs, exploratory dry holes, impairment and amortization of unproved leasehold costs and lease rentals. The costs of exploratory wells and exploratory-type stratigraphic wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a 12-month period after drilling is complete.

On the sale of a complete or partial unit of a proved property or pipeline and related facilities, the cost and related accumulated DD&A are removed from the property accounts and any gain or loss is recognized.

For sales of our entire working interests in proved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of less than all of our working interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

Unproved Oil and Natural Gas Properties

Unproved properties consist of costs incurred to acquire unproved leases, or lease acquisition costs. Unproved lease acquisition costs are capitalized until reclassified from unproved properties to proved properties when proved reserves are discovered on or otherwise attributed to the property or are expensed as the leases expire or we specifically identify leases that are probable of reverting to the lessor. At December 31, 2018, we had $3.0 billion of undeveloped leasehold. Of the remaining undeveloped leasehold costs at December 31, 2018, $419.8 million is scheduled to expire in 2019. The leasehold expiring in 2019 relates to areas in which we are actively drilling. If our drilling is not successful, this leasehold could become partially or entirely impaired.

Impairment of Long-Lived Assets, Including Proved Oil and Natural Gas Properties

We review our long-lived assets to be held and used, including proved oil and natural gas properties by field. 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 related to proved properties in the applicable field is less than the carrying amount of the assets. In this circumstance, we recognize an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset. We review our oil and natural gas properties by amortization base or by individual well for those wells not constituting part of an amortization base. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value (discounted future cash flows) of the properties would be recognized at that time. Estimating future cash flows involves the use of judgments, including estimation of the proved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs. See *Note 14—Disclosures about Fair Value of Financial Instruments* to our consolidated financial statements included elsewhere in this Annual Report for additional information regarding our impairment of proved oil and natural gas properties.

Impairment of Unproved Oil and Natural Gas Properties

Unproved oil and natural gas properties are assessed periodically for impairment on a property by property basis by considering future drilling plans, the results of exploration activities, commodity price outlooks, planned future sales, remaining lease terms and the expiration of all or a portion of such projects. Our periodic assessment also considers our ability to enter into leasehold exchange transactions that allow for higher concentrations of ownership and development. We recognize impairment expense for unproved properties at the earlier of the time when the lease term has expired or management estimates the lease will expire before it is drilled, sold or traded. The impairment of unproved oil and natural gas properties is recorded in *Exploration and abandonment costs* in our consolidated statement of operations. Based on this assessment, we expensed $127.0 million of undeveloped leasehold in the fourth quarter of 2018 related to the expected future abandonment of expiring acreage.

We consider the following factors in our assessment of the impairment of unproved properties:

- the remaining length of unexpired term under our leases;
- our ability to actively manage and prioritize our capital expenditures to drill wells on undeveloped leases or make payments to extend leases that may be close to expiration;
- our ability to exchange leasehold positions with other companies that allow for higher concentrations of ownership and development potential; and
- our ability to convey partial mineral ownership to other companies in exchange for their drilling of leases.

Allocation of Purchase Price in Acquisitions

As part of our business strategy, we regularly pursue the acquisition of oil and natural gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and natural gas reserves and unproved properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

Oil and Natural Gas Reserves and Standardized Measure of Discounted Net Future Cash Flows

The estimates of proved oil and natural gas reserves utilized in the preparation of the consolidated financial statements are estimated in accordance with the rules established by the SEC and the FASB. These rules require that reserve estimates be prepared under existing economic and operating conditions using a trailing first day of the month 12-month average price, net of historical differentials, with no provision for price and cost escalations in future years except by contractual arrangements.

Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. Oil and gas properties are depleted by field using the units-of-production method. Capitalized drilling and development costs of producing oil and natural gas properties are depleted over proved developed reserves and leasehold costs are depleted over total proved reserves. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above, may be increased or decreased. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

This Annual Report presents estimates of our proved reserves as of December 31, 2018, which have been prepared and presented in accordance with SEC guidelines. The pricing that was used for estimates of our reserves as of December 31, 2018 was based on an unweighted first day of the month average 12-month WTI Phillips 66 posted price, net of differential, of $61.88 per Bbl for oil and $28.05 per Bbl for NGLs and a Waha spot natural gas price, net of differential, of $1.64 per MMBtu for natural gas.

Our internal reserve engineers and technical staff prepare the estimates of our oil and natural gas reserves and associated future net cash flows, which are then audited by NSAI, our independent third party petroleum consulting firm. Even though our internal reserve engineers, technical staff and independent reserve engineers are knowledgeable and follow authoritative guidelines for estimating and auditing reserves, they must make a number of subjective assumptions based on professional judgments in developing and auditing the reserve estimates. Reserve estimates are updated at least annually and consider recent production levels and other technical information about each field. Periodic revisions to the estimated reserves and future net cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly alter future depletion and result in impairment of long-lived assets that may be material.

It should not be assumed that the Standardized Measure included in this Annual Report as of December 31, 2018 is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based the 2018 Standardized Measure on a 12-month average of commodity prices on the first day of the month 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 1A. Risk Factors” and “Item 2. Properties” for additional information regarding estimates of proved reserves.

Our estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, the rate at which we record depletion expense will increase, reducing future earnings. Such a decline may result from lower commodity prices, which may make it uneconomical to drill and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of our assessment of our proved properties for impairment.

Income Taxes

We account for income taxes using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry forwards. Deferred tax assets and liabilities are calculated by applying existing tax laws and the rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. The tax returns and the amount of taxable income or loss are subject to examination by federal and state taxing authorities.

We periodically assess whether it is more likely than not that we will generate sufficient taxable income to realize our deferred income tax assets, including net operating losses. In making this determination, we consider all available positive and negative evidence and make certain assumptions. We consider, among other things, our deferred tax liabilities, the overall business environment, our historical earnings and losses, current industry trends and its outlook for future years.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2018, 2017 and 2016. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and natural gas prices increase drilling activity in our areas of operations.

Off-Balance Sheet Arrangements

As of December 31, 2018, we were party to certain transportation and sale agreements providing for the delivery of fixed and determinable quantities of oil and natural gas. If production volumes are not sufficient to meet these contracted delivery commitments, we may be subject to deficiency fees unless we purchase commodities in the market to satisfy such commitments. See *Note 13—Commitments and Contingencies* to our consolidated financial statements included elsewhere in this Annual Report.

We do not otherwise maintain off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities or others that are reasonably likely to have a material current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources which are not disclosed in the notes to our consolidated financial statements.

Recent Accounting Pronouncements

For information regarding recently issued accounting pronouncements that impact us, see *Note 2— Summary of Significant Accounting Policies* in our condensed consolidated financial statements, which is incorporated herein by reference.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in the prices of the commodities we sell. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil and natural gas production. Pricing for our production has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. The prices we receive for our production depend on many factors outside of our control, such as the strength of the global economy and global supply and demand for the commodities we produce.

We enter into multiple types of commodity derivative contracts to (i) reduce the effect of price volatility on our oil and natural gas revenues and (ii) support our annual capital budgeting and expenditure plans. We plan to continue our practice of entering into such transactions at times and on terms desired to maintain a portfolio of commodity derivative contracts covering a portion of our projected oil production. Future transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling price. These hedging activities are intended to support oil prices at targeted levels and to manage our exposure to oil price fluctuations. For a description of our open positions at December 31, 2018, see *Note 4—Derivative Financial Instruments* to our consolidated financial statements included elsewhere in this Annual Report.

We do not require collateral from our counterparties for entering into derivative instruments, so in order to mitigate the credit risk associated with such derivative instruments, we typically enter into an International Swap Dealers Association Master Agreement ("ISDA Agreement") with our counterparties. The ISDA Agreement is a standardized, bilateral contract between a given counterparty and us. Instead of treating each derivative transaction between the counterparty and us separately, the ISDA Agreement enables the counterparty and us to aggregate all trades under such agreement and treat them as a single agreement. This arrangement is intended to benefit us in two ways: (i) default by a counterparty under a single trade can trigger rights to terminate all trades with such counterparty that are subject to the ISDA Agreement; and (ii) netting of settlement amounts reduces our credit exposure to a given counterparty in the event of close-out.

As of December 31, 2018, the fair market value of our oil and natural gas derivative contracts was a net asset of $42.5 million, including deferred premium payables of $54.4 million. The deferred premium payable is a fixed amount and is not marked to fair market value. As of December 31, 2018, the fair market value of our oil derivative contracts was a net asset of $42.7 million. Based on our open oil derivative positions at December 31, 2018, a 10% increase in the NYMEX WTI price would decrease our net oil derivative asset by approximately $21.8 million, while a 10% decrease in the NYMEX WTI price would increase our net oil derivative asset by approximately $20.3 million. As of December 31, 2018, the fair market value of our natural gas derivative contracts was a net liability of $0.2 million. Based on our open natural gas derivative positions at December 31, 2018, a 10% increase in the NYMEX Henry Hub price would increase our net natural gas derivative liability by approximately $0.2 million, while a 10% decrease in the NYMEX Henry Hub price would decrease our natural gas derivative liability by approximately $0.1 million. Please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Overview—Realized Prices on the Sale of Oil, Natural Gas and NGLs."

Counterparty Risk

Our derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require our counterparties to our derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as we deem appropriate. This evaluation includes reviewing a counterparty's credit rating and latest financial information. We plan to continue to evaluate the credit standings of our counterparties in a similar manner. The majority of our derivative contracts currently in place are with lenders under our Revolving Credit Agreement, each of whom has an investment grade rating.

Interest Rate Risk

Our market risk exposure related to changes in interest rates relates primarily to debt obligations and the amount of interest we earn on our short-term investments. As of December 31, 2018, we had $2.2 billion (excluding capital lease obligations) of fixed-rate long-term debt outstanding with a weighted average interest rate of 5.6%. Although near term changes may impact the fair value of our fixed-rate debt, they do not expose us to interest rate risk or cash flow loss. We are exposed to interest rate risk as a result of our Revolving Credit Agreement, which requires us to pay higher interest rate margins as we utilize a larger percentage of our available commitments. As of December 31, 2018, however, we had no outstanding borrowings under our Revolving Credit Agreement and therefore an increase in interest rates will not result in increased interest expense until such time that we determine to make borrowings under our Revolving Credit Agreement. We are also exposed to interest rate risk related to our interest-bearing cash and cash equivalents and short-term investment balances. As of December 31, 2018, our cash and cash equivalents were $163.2 million. A change in the interest rate applicable to our Revolving Credit Agreement or short-term investments would have a de minimis impact.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

In accordance with Exchange Act Rules 13a-15 and 15d-15, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2018. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2018, at the reasonable assurance level.

Management's Annual Report on Internal Control over Financial Reporting and Attestation Report of the Registered Public Accounting Firm

Our management, including our principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our consolidated financial statements for external purposes in accordance with GAAP.

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.

Our management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2018, using the criteria in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation, our management believes that our internal control over financial reporting was effective as of December 31, 2018.

This Annual Report includes an attestation report of KPMG LLP, our independent registered public accounting firm, on our internal control over financial reporting as of December 31, 2018, which is included in this Annual Report on page F-3.

Changes in Internal Control over Financial Reporting

There were no changes in our system of internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) during the quarter ended December 31, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required in response to this item will be set forth in our definitive proxy statement for the 2019 annual meeting of stockholders and is incorporated herein by reference.

Section 16(a) Beneficial Ownership Reporting Compliance

The information required in response to this item will be set forth in our definitive proxy statement for the 2019 annual meeting of stockholders and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this item will be set forth in our definitive proxy statement for the 2019 annual meeting of stockholders and is incorporated herein by reference.

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

The information required in response to this item will be set forth in our definitive proxy statement for the 2019 annual meeting of stockholders 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 our definitive proxy statement for the 2019 annual meeting of stockholders and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required in response to this item will be set forth in our definitive proxy statement for the 2019 annual meeting of stockholders and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

1. The following documents are filed as part of this Annual Report or incorporated by reference:

    a. Financial Statements:

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

    b. Financial Statement Schedules:

    All financial statement schedules have been omitted because they are not applicable or the required information is presented in the consolidated financial statements and related notes.

2. Exhibits

    The exhibits required to be filed by this Item 15(b) are set forth in the Exhibit Index included below.

EXHIBIT INDEX

Exhibit No.	
2.1#	Purchase and Sale Agreement, dated August 15, 2016, by and between Parsley Energy, L.P. and BTA Oil Producers, LLC, et al. (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on October 5, 2016).
2.2#	First Amendment to Purchase and Sale Agreement, dated October 4, 2016, by and between Parsley Energy, L.P. and BTA Oil Producers, LLC, et al. (incorporated by reference to Exhibit 2.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on October 5, 2016).
2.3#	Contribution Agreement, dated as of February 7, 2017, by and between Parsley Energy, LLC, Parsley Energy, Inc., Double Eagle Energy Permian Operating LLC, Double Eagle Energy Permian LLC and Double Eagle Energy Permian Member LLC (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on February 7, 2017).
2.4#	First Amendment to Contribution Agreement, dated as of March 10, 2017, by and among Parsley Energy, LLC, Parsley Energy, Inc., Double Eagle Energy Permian Operating LLC, Double Eagle Energy Permian LLC and Double Eagle Energy Permian Member LLC (incorporated by reference to Exhibit 2.2 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on May 5, 2017).
2.5#	Second Amendment to Contribution Agreement, dated as of April 7, 2017, by and among Parsley Energy, LLC, Parsley Energy, Inc., Double Eagle Energy Permian Operating LLC, Double Eagle Energy Permian LLC and Double Eagle Energy Permian Member LLC (incorporated by reference to Exhibit 2.3 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on May 5, 2017).
2.6#	Third Amendment to Contribution Agreement, dated as of April 19, 2017, by and among Parsley Energy, LLC, Parsley Energy, Inc., Double Eagle Energy Permian Operating LLC, Double Eagle Energy Permian LLC and Double Eagle Energy Permian Member LLC (incorporated by reference to Exhibit 2.4 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on May 5, 2017).
2.7#	Fourth Amendment and Waiver to Contribution Agreement, dated as of March 19, 2018, by and among Double Eagle Energy Holdco, LLC, as agent and attorney-in-fact for each member of Double Eagle Energy Permian LLC and their successors and assigns, Parsley Energy, LLC and Parsley Energy, Inc. (incorporated by reference to Exhibit 2.1 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on May 4, 2018).
3.1	Amended and Restated Certificate of Incorporation of Parsley Energy, Inc. (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
3.2	Amended and Restated Bylaws of Parsley Energy, Inc., dated October 26, 2018 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on October 30, 2018).
4.1*	Specimen Class A Common Stock Certificate
4.2	Indenture, dated May 27, 2016, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 6.250% Senior Notes due 2024 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on May 27, 2016).
4.3	First Supplemental Indenture, dated August 18, 2016, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 6.250% Senior Notes due 2024 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on August 19, 2016).
4.4	Second Supplemental Indenture, dated October 27, 2016, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 6.250% Senior Notes due 2024 (incorporated by reference to Exhibit 4.5 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on November 4, 2016).
4.5	Third Supplemental Indenture, dated April 20, 2017, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 6.250% Senior Notes due 2024 (incorporated by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on April 20, 2017).

Exhibit No.	
4.6	Indenture, dated December 13, 2016, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 5.375% Senior Notes due 2025 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on December 13, 2016).
4.7	First Supplemental Indenture, dated April 20, 2017, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 5.375% Senior Notes due 2025 (incorporated by reference to Exhibit 4.4 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on April 20, 2017).
4.8	Indenture, dated February 13, 2017, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 5.250% Senior Notes due 2025 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on February 13, 2017).
4.9	First Supplemental Indenture, dated April 20, 2017, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 5.250% Senior Notes due 2025 (incorporated by reference to Exhibit 4.5 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on April 20, 2017).
4.10	Indenture, dated October 11, 2017, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee, related to the 5.625% Senior Notes due 2027 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on October 11, 2017).
4.11	Registration Rights and Lock-Up Agreement, dated as of April 20, 2017, by and between Parsley Energy, Inc. and the Holders party thereto (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on April 20, 2017).
4.12	Second Amended and Restated Registration Rights Agreement, dated as of April 20, 2017, by and among Parsley Energy, LLC, Parsley Energy, Inc. and each of the parties listed as Owners on the signature pages thereto (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on April 20, 2017).
10.1	Credit Agreement, dated October 28, 2016, among Parsley Energy, LLC, as borrower, Parsley Energy, Inc., Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on November 2, 2016).
10.2	First Amendment to Credit Agreement, dated as of February 13, 2017, among Parsley Energy, LLC, as borrower, Parsley Energy, Inc., each of the guarantors party thereto, Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on May 1, 2017).
10.3	Second Amendment to Credit Agreement, dated as of April 11, 2017, among Parsley Energy, LLC, as borrower, Parsley Energy, Inc., each of the guarantors party thereto, Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on May 1, 2017).
10.4	Third Amendment to Credit Agreement, dated as of April 28, 2017, among Parsley Energy, LLC, as borrower, Parsley Energy, Inc., each of the guarantors party thereto, Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on May 1, 2017).
10.5	Fourth Amendment to Credit Agreement, dated as of May 22, 2017, among Parsley Energy, LLC, as borrower, Parsley Energy, Inc., each of the guarantors party thereto, Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on August 4, 2017).

Exhibit No.	
10.6	Fifth Amendment to Credit Agreement, dated as of October 11, 2017, among Parsley Energy, LLC, as borrower, Parsley Energy, Inc., each of the guarantors party thereto, Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on October 11, 2017).
10.7	Sixth Amendment to Credit Agreement, dated as of April 30, 2018, among Parsley Energy, LLC, as borrower, Parsley Energy, Inc., each of the guarantors party thereto, Wells Fargo Bank, National Association, as administrative agent, JPMorgan Chase Bank, N.A., as syndication agent, BMO Harris Bank, N.A., as documentation agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on May 3, 2018).
10.8	Purchase Agreement, dated May 24, 2016, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers named therein (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on May 27, 2016).
10.9	Purchase Agreement, dated August 16, 2016, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and J.P. Morgan Securities LLC, as representative of the several initial purchasers named therein (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on August 19, 2016).
10.10	Purchase Agreement, dated December 6, 2016, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers named therein (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on December 7, 2016).
10.11	Purchase Agreement, dated February 8, 2017, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers named therein (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on February 13, 2017).
10.12	Purchase Agreement, dated October 5, 2017, by and among Parsley Energy, LLC, Parsley Finance Corp., the subsidiary guarantors named therein and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers named therein (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on October 11, 2017).
10.13†	Employment Agreement, dated as of January 23, 2014, by and between Parsley Energy Operations, LLC and Bryan Sheffield (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on April 11, 2014).
10.14†	First Amendment to Employment, Confidentiality and Non-Competition Agreement, dated as of September 30, 2016, by and between Parsley Energy Operations, LLC and Bryan Sheffield (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on November 4, 2016).
10.15†	Letter Agreement, dated as of February 15, 2019, by and between Parsley Energy, Inc. and Bryan Sheffield (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on February 15, 2019).
10.16†	Amended and Restated Employment, Confidentiality and Non-Competition Agreement, dated December 28, 2018, by and between Parsley Energy Operations, LLC and Matt Gallagher (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on December 28, 2018).
10.17†	First Amendment to Amended and Restated Employment, Confidentiality and Non-Competition Agreement, dated as of February 15, 2019, by and between Parsley Energy Operations, LLC and Matt Gallagher (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on February 15, 2019).
10.18†	Amended and Restated Employment, Confidentiality and Non-Competition Agreement, dated December 28, 2018, by and between Parsley Energy Operations, LLC and Ryan Dalton (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on December 28, 2018).
10.19†	Employment, Confidentiality and Non-Competition Agreement, dated September 26, 2018, by and between Parsley Energy Operations, LLC and David Dell'Osso (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on September 26, 2018)

Exhibit No.	
10.20†	Second Amended and Restated Employment, Confidentiality and Non-Competition Agreement, dated December 28, 2018, by and between Parsley Energy Operations, LLC and Colin Roberts (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on December 28, 2018).
10.21†	Employment, Confidentiality and Non-Competition Agreement, dated as of February 26, 2014, by and between Parsley Energy Operations, LLC and Michael Hinson (incorporated by reference to Exhibit 10.20 to the Company's Annual Report on Form 10-K, File No. 001-36463, filed with the SEC on February 28, 2018).
10.22†	First Amendment to Employment, Confidentiality and Non-Competition Agreement, dated as of September 30, 2016, by and between Parsley Energy Operations, LLC and Michael Hinson (incorporated by reference to Exhibit 10.21 to the Company's Annual Report on Form 10-K, File No. 001-36463, filed with the SEC on February 28, 2018).
10.23	Third Amended and Restated Limited Liability Company Agreement of Parsley Energy, LLC, dated as of February 20, 2019 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on February 26, 2019).
10.24	Tax Receivable Agreement, dated as of May 29, 2014, by and among Parsley Energy, Inc., certain members of Parsley Energy, LLC and Bryan Sheffield (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.25†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Bryan Sheffield (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.26†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Ryan Dalton (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.27†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Michael Hinson (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.28†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Matt Gallagher (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.29†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and Colin Roberts (incorporated by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.30†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and David Smith (incorporated by reference to Exhibit 10.11 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.31†	Indemnification Agreement, dated as of May 14, 2014, by and between Parsley Energy, Inc. and A.R. Alameddine (incorporated by reference to Exhibit 10.12 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on June 4, 2014).
10.32†	Indemnification Agreement, dated as of July 23, 2014, by and between Parsley Energy, Inc. and Hemang Desai (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on July 24, 2014).
10.33†	Indemnification Agreement, dated as of August 19, 2014, by and between Parsley Energy, Inc. and William Browning (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on August 25, 2014).
10.34†	Indemnification Agreement, dated as of March 23, 2016, by and between Parsley Energy, Inc. and Ronald Brokmeyer (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on March 23, 2016).
10.35†	Indemnification Agreement, dated as of December 21, 2016, by and between Parsley Energy, Inc. and Jerry Windlinger (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on December 21, 2016).
10.36†	Indemnification Agreement, dated as of August 1, 2017, by and between Parsley Energy, Inc. and Karen Hughes (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on August 3, 2017).

Exhibit No.	
10.37†	Indemnification Agreement, dated September 26, 2018, by and between Parsley Energy, Inc. and David Dell'Osso (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on September 26, 2018).
10.38†	Form of Director Agreement (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on August 8, 2018).
10.39†	Amended and Restated Parsley Energy, Inc. 2014 Long Term Incentive Plan (incorporated by reference to Exhibit 10.30 to the Company's Annual Report on Form 10-K, File No. 001-36463, filed with the SEC on March 11, 2015).
10.40†	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.16 to Amendment No. 2 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on May 12, 2014).
10.41†	First Amendment to Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on November 4, 2016).
10.42†	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on November 4, 2016).
10.43†	Form of Notice of Grant of Restricted Stock (Time-Based) (incorporated by reference to Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q, File No. 001-36463, filed with the SEC on November 4, 2016).
10.44†	Form of Notice of Grant of Restricted Stock (Performance-Based) (incorporated by reference to Exhibit 10.18 to Amendment No. 2 to the Company's Registration Statement on Form S-1, File No. 333-195230, filed with the SEC on May 12, 2014).
10.45†	Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.34 to the Company's Annual Report on Form 10-K, File No. 001-36463, filed with the SEC on March 11, 2015).
10.46†	Form of Notice of Grant of Restricted Stock Units (Time-Based) (incorporated by reference to Exhibit 10.35 to the Company's Annual Report on Form 10-K, File No. 001-36463, filed with the SEC on March 11, 2015).
10.47†	Form of Notice of Grant of Restricted Stock Units (Performance-Based) (incorporated by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K, File No. 001-36463, filed with the SEC on March 11, 2015).
10.48†	Form of Notice of Grant of Restricted Stock (Performance-Based) (incorporated by reference to Exhibit 10.58 to the Company's Annual Report on Form 10-K, File No. 001-36463, filed with the SEC on February 28, 2018).
10.49†	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.59 to the Company's Annual Report on Form 10-K, File No. 001-36463, filed with the SEC on February 28, 2018).
10.50†	Parsley Energy, Inc. Nonqualified Deferred Compensation Plan, effective as of December 21, 2018 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-36463, filed with the SEC on December 28, 2018).
21.1*	List of Subsidiaries of Parsley Energy, Inc.
23.1*	Consent of KPMG LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Netherland, Sewell & Associates, Inc. Audit Letter.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.

Exhibit No.	
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Labels Linkbase Document.

† Management contract or compensatory plan or agreement

* Filed herewith.

** Furnished herewith. Pursuant to SEC Release No. 33-8212, this certification will be treated as "accompanying" this Annual Report on Form 10-K and not "filed" as part of such report for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of Section 18 of the Exchange Act and this certification will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, except to the extent that the registrant specifically incorporates it by reference.

Schedules and similar attachments have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The registrant will furnish a supplemental copy of any omitted schedule or similar attachment to the Commission upon request.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

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

February 27, 2019	By:	/s/ Matt Gallagher
		Matt Gallagher President and Chief Executive Officer

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

February 27, 2019	By:	/s/ Matt Gallagher
		Matt Gallagher President, Chief Executive Officer and Director (Principal Executive Officer)
February 27, 2019	By:	/s/ Ryan Dalton
		Ryan Dalton Executive Vice President—Chief Financial Officer (Principal Accounting and Financial Officer)
February 27, 2019	By:	/s/ A.R. Alameddine
		A.R. Alameddine Director
February 27, 2019	By:	/s/ Ronald Brokmeyer
		Ronald Brokmeyer Director
February 27, 2019	By:	/s/ William Browning
		William Browning Director
February 27, 2019	By:	/s/ Hemang Desai
		Hemang Desai Director
February 27, 2019	By:	/s/ Karen Hughes
		Karen Hughes Director
February 27, 2019	By:	/s/ Bryan Sheffield
		Bryan Sheffield Executive Chairman and Chairman of the Board
February 27, 2019	By:	/s/ David H. Smith
		David H. Smith Director
February 27, 2019	By:	/s/ Jerry Windlinger
		Jerry Windlinger Director

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Report of Independent Registered Public Accounting Firm

The stockholders and board of directors
Parsley Energy, Inc.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Parsley Energy, Inc. and subsidiaries (the Company) as of December 31, 2018 and 2017, the related consolidated statements of operations, changes in equity, and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2018, 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, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 27, 2019 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Change in Accounting Principle

As discussed in Note 2 to the consolidated financial statements, the Company has changed its method of accounting for revenue recognition in 2018 due to the adoption of Accounting Standards Codification Topic 606 *Revenue from Contracts with Customers.*

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated 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 consolidated 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 consolidated 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 consolidated 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 consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

(signed) KPMG LLP

We have served as the Company's auditor since 2013.

Dallas, Texas
February 27, 2019

Report of Independent Registered Public Accounting Firm

The stockholders and board of directors
Parsley Energy, Inc.:

Opinion on Internal Control Over Financial Reporting

We have audited Parsley Energy, Inc. *and* subsidiaries' (the Company) internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2018 and 2017, the related consolidated statements of operations, changes in equity, and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements), and our report dated February 27, 2019 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying consolidated financial statements. 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 of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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.

(signed) KPMG LLP

Dallas, Texas
February 27, 2019

PARSLEY ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2018	December 31, 2017
	(In thousands, except share data)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 163,216	$ 554,189
Short-term investments	—	149,283
Accounts receivable, net of allowance for doubtful accounts:		
Joint interest owners and other	36,062	42,174
Oil, natural gas and NGLs	138,987	123,147
Related parties	94	388
Short-term derivative instruments	191,297	41,957
Assets held for sale	—	1,790
Other current assets	11,056	6,558
Total current assets	540,712	919,486
PROPERTY, PLANT AND EQUIPMENT		
Oil and natural gas properties, successful efforts method	9,948,246	8,551,314
Accumulated depreciation, depletion, amortization and impairment	(1,295,098)	(822,459)
Total oil and natural gas properties, net	8,653,148	7,728,855
Other property, plant and equipment net	170,739	106,587
Total property, plant and equipment, net	8,823,887	7,835,442
NONCURRENT ASSETS		
Assets held for sale, net	—	14,985
Long-term derivative instruments	20,124	15,732
Other noncurrent assets	6,640	7,553
Total noncurrent assets	26,764	38,270
TOTAL ASSETS	$ 9,391,363	$ 8,793,198
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued expenses	$ 364,803	$ 407,698
Revenue and severance taxes payable	127,265	109,917
Current portion of long-term debt	2,413	2,352
Short-term derivative instruments	152,330	84,919
Current portion of asset retirement obligations	2,134	7,203
Total current liabilities	648,945	612,089
NONCURRENT LIABILITIES		
Liabilities related to assets held for sale	—	405
Long-term debt	2,181,667	2,179,525
Asset retirement obligations	24,750	19,967
Deferred tax liability, net	131,523	21,403
Payable pursuant to tax receivable agreement	68,110	58,479
Long-term derivative instruments	16,633	20,624
Total noncurrent liabilities	2,422,683	2,300,403
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY		
Preferred stock, $0.01 par value, 50,000,000 shares authorized, none issued and outstanding	—	—
Common stock		
Class A, $0.01 par value, 600,000,000 shares authorized, 280,827,038 shares issued and 280,205,293 shares outstanding at December 31, 2018 and 252,419,601 shares issued and 252,260,300 shares outstanding at December 31, 2017	2,808	2,524
Class B, $0.01 par value, 125,000,000 shares authorized, 36,547,731 and 62,128,257 issued and outstanding at December 31, 2018 and December 31, 2017	366	622
Additional paid in capital	5,163,987	4,666,365
Retained earnings	412,646	43,519
Treasury stock, at cost, 621,745 shares and 159,301 at December 31, 2018 and December 31, 2017	(11,749)	(735)
Total stockholders' equity	5,568,058	4,712,295
Noncontrolling interest	751,677	1,168,411
Total equity	6,319,735	5,880,706
TOTAL LIABILITIES AND EQUITY	$ 9,391,363	$ 8,793,198

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

PARSLEY ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year ended December 31,		
	2018	2017	2016
	(In thousands, except per share data)		
REVENUES			
Oil sales	$ 1,536,244	$ 802,230	$ 387,303
Natural gas sales	51,231	56,571	30,928
Natural gas liquids sales	227,272	103,193	38,273
Other	11,684	5,050	1,269
Total revenues	1,826,431	967,044	457,773
OPERATING EXPENSES			
Lease operating expenses	144,292	102,169	59,293
Transportation and processing costs	32,573	—	—
Production and ad valorem taxes	108,342	59,641	27,916
Depreciation, depletion and amortization	584,857	352,247	233,766
General and administrative expenses (including stock-based compensation of $19,877, $19,619 and $12,871 for the years ended December 31, 2018, 2017 and 2016)	150,955	124,255	84,591
Exploration and abandonment costs	162,539	39,345	9,627
Acquisition costs	167	10,977	1,081
Accretion of asset retirement obligations	1,422	971	732
(Gain) loss on sale of property	(6,454)	14,332	119
Other operating expenses	19,863	10,638	9,620
Total operating expenses	1,198,556	714,575	426,745
OPERATING INCOME (LOSS)	627,875	252,469	31,028
OTHER (EXPENSE) INCOME			
Interest expense, net	(131,460)	(97,381)	(56,225)
Loss on early extinguishment of debt	—	(3,891)	(36,335)
Gain (loss) on derivatives	50,342	(66,135)	(50,835)
Change in TRA liability	(437)	35,847	7,351
Interest income	5,464	7,936	992
Other income (expense)	(340)	783	(2,317)
Total other expense, net	(76,431)	(122,841)	(137,369)
INCOME (LOSS) BEFORE INCOME TAXES	551,444	129,628	(106,341)
INCOME TAX (EXPENSE) BENEFIT	(105,475)	(5,708)	17,424
NET INCOME (LOSS)	445,969	123,920	(88,917)
LESS: NET (INCOME) LOSS ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(76,842)	(17,146)	14,735
NET INCOME (LOSS) ATTRIBUTABLE TO PARSLEY ENERGY, INC. STOCKHOLDERS	$ 369,127	$ 106,774	$ (74,182)
Net income (loss) per common share:			
Basic	$ 1.36	$ 0.44	$ (0.46)
Diluted	$ 1.35	$ 0.42	$ (0.46)
Weighted average common shares outstanding:			
Basic	272,226	240,733	161,793
Diluted	272,884	296,512	161,793

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

PARSLEY ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(In thousands)

	Issued Shares						Shares				
	Class A common stock	Class B common stock	Class A common stock	Class B common stock	Additional paid in capital	(Accumulated deficit) retained earnings	Treasury stock	Treasury stock	Total stockholders' equity	Noncontrolling interest	Total equity
Balance at 12/31/2015	136,729	32,145	$ 1,360	$ 321	$ 1,252,020	$ 10,868	105	$ (77)	$ 1,264,492	$ 322,149	$ 1,586,641
Adoption of ASU 2016-09	—	—	—	—	—	59	—	—	59	—	59
Restated balance	136,729	32,145	1,360	321	1,252,020	10,927	105	(77)	1,264,551	322,149	1,586,700
Issuance proceeds, net of underwriters discount and expenses	38,812	—	388	—	929,927	—	—	—	930,315	—	930,315
Change in equity due to issuance of PE Units by Parsley LLC	—	—	—	—	(80,255)	—	—	—	(80,255)	80,255	—
Increase in net deferred tax liability due to issuance of PE Units by Parsley LLC	—	—	—	—	(13,215)	—	—	—	(13,215)	—	(13,215)
Exchange of PE Units and Class B common stock for Class A common stock	4,137	(4,137)	41	(41)	47,001	—	—	—	47,001	(47,001)	—
Change in net deferred tax liability due to exchange of PE Units and Class B common stock for Class A common stock	—	—	—	—	(5,999)	—	—	—	(5,999)	—	(5,999)
Tax benefit from tax receivable agreement	—	—	—	—	8,855	—	—	—	8,855	—	8,855
Issuance of restricted stock	37	—	—	—	—	—	—	—	—	—	—
Vesting of restricted stock units	15	—	8	—	(8)	—	—	(91)	(91)	—	(91)
Repurchase of common stock	—	—	—	—	—	—	12	(213)	(213)	—	(213)
Restricted stock forfeited	—	—	—	—	(105)	—	22	—	(105)	—	(105)
Stock-based compensation	—	—	—	—	12,976	—	—	—	12,976	—	12,976
Net loss	—	—	—	—	—	(74,182)	—	—	(74,182)	(14,735)	(88,917)
Balance at 12/31/2016	179,730	28,008	$ 1,797	$ 280	$ 2,151,197	$ (63,255)	139	$ (381)	$ 2,089,638	$ 340,668	$ 2,430,306
Issuance proceeds, net of underwriters discount and expenses	66,700	—	667		2,122,860	—	—	—	2,123,527	—	2,123,527
Shares of Class B common stock issued for acquisition	—	39,849	—	399	1,182,919	—	—	—	1,183,318	—	1,183,318
Change in equity due to issuance of PE Units by Parsley LLC	—	—	—	—	(915,749)	—	—	—	(915,749)	915,749	—
Exchange of PE Units and Class B common stock for Class A common stock	5,729	(5,729)	57	(57)	105,522	—	—	—	105,522	(105,522)	—
Issuance of restricted stock	228	—	3	—	(3)	—	—	—	—	370	370
Vesting of restricted stock units	33	—	—	—	—	—	—	—	—	—	—
Repurchase of common stock	—	—	—	—	—	—	12	(354)	(354)	—	(354)
Restricted stock forfeited	—	—	—	—	(14)	—	8	—	(14)	—	(14)
Stock-based compensation	—	—	—	—	19,633	—	—	—	19,633	—	19,633
Net income	—	—	—	—	—	106,774	—	—	106,774	17,146	123,920
Balance at 12/31/2017	252,420	62,128	$ 2,524	$ 622	$ 4,666,365	$ 43,519	159	$ (735)	$ 4,712,295	$ 1,168,411	$ 5,880,706
Exchange of PE Units and Class B common stock for Class A common stock	25,580	(25,580)	256	(256)	491,614	—	—	—	491,614	(491,614)	—
Change in net deferred tax liability due to exchange of PE Units	—	—	—	—	(13,841)	—	—	—	(13,841)	—	(13,841)
Distribution to owners from consolidated subsidiary	—	—	—	—	—	—	—	—	—	(1,962)	(1,962)
Issuance of restricted stock	803	—	8	—	(8)	—	—	—	—	—	—
Vesting of restricted stock units	926	—	9	—	(9)	—	—	—	—	—	—
Repurchase of common stock	—	—	—	—	—	—	435	(11,014)	(11,014)	—	(11,014)
Restricted stock forfeited	—	—	—	—	(967)	—	28	—	(967)	—	(967)
Conversion of restricted stock units to restricted stock awards	1,098	—	11	—	(11)	—	—	—	—	—	—
Stock-based compensation	—	—	—	—	20,844	—	—	—	20,844	—	20,844
Net income	—	—	—	—	—	369,127	—	—	369,127	76,842	445,969
Balance at 12/31/2018	280,827	36,548	$ 2,808	$ 366	$ 5,163,987	$ 412,646	622	$ (11,749)	$ 5,568,058	$ 751,677	$ 6,319,735

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

PARSLEY ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2018	2017	2016
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 445,969	$ 123,920	$ (88,917)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	584,857	352,247	233,766
Leasehold abandonments	160,834	32,872	6,063
Accretion of asset retirement obligations	1,422	971	732
(Gain) loss on sale of property	(6,454)	14,332	119
Loss on early extinguishment of debt	—	3,891	36,335
Amortization and write off of deferred loan origination costs	4,745	4,720	3,190
Amortization of bond premium	(516)	(516)	(874)
Deferred income tax expense (benefit)	105,475	5,752	(17,582)
Change in TRA liability	437	(35,847)	(7,351)
Stock-based compensation expense	19,877	19,619	12,871
(Gain) loss on derivatives	(50,342)	66,135	50,835
Net cash received for derivative settlements	6,279	16,172	32,364
Net cash (paid) received for option premiums	(47,644)	(28,426)	(10,334)
Other	3,533	1,907	106
Changes in operating assets and liabilities, net of acquisitions:			
Accounts receivable	(12,956)	(95,239)	(35,774)
Accounts receivable—related parties	294	(98)	100
Other current assets	(689)	45,417	(39,295)
Other noncurrent assets	(100)	(536)	748
Accounts payable and accrued expenses	(13,395)	122,992	20,897
Revenue and severance taxes payable	17,348	40,465	32,343
Net cash provided by operating activities	1,218,974	690,750	230,342
CASH FLOWS FROM INVESTING ACTIVITIES:			
Development of oil and natural gas properties	(1,787,673)	(1,089,256)	(505,802)
Acquisitions of oil and natural gas properties	(136,972)	(2,192,093)	(1,346,190)
Additions to other property and equipment	(93,457)	(54,896)	(33,374)
Proceeds from sale of property	233,647	30,537	—
Maturity of short-term investments	149,331	—	—
Purchases of short-term investments	—	(149,283)	—
Other	41,088	(1,869)	—
Net cash used in investing activities	(1,594,036)	(3,456,860)	(1,885,366)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under long-term debt	—	1,152,780	1,057,500
Payments on long-term debt	(2,888)	(74,769)	(521,944)
Debt issue costs	(47)	(17,371)	(18,097)
Proceeds from issuance of common stock, net	—	2,123,344	930,315
Purchases of common stock	(11,014)	(354)	(213)
Distribution to owner of consolidated subsidiary	(1,962)	—	—
Vesting of restricted stock units	—	—	(91)
Net cash (used in) provided by financing activities	(15,911)	3,183,630	1,447,470
Net (decrease) increase in cash and cash equivalents	(390,973)	417,520	(207,554)
Cash, cash equivalents, and restricted cash at beginning of year	554,189	136,669	344,223
Cash, cash equivalents, and restricted cash at end of year	$ 163,216	$ 554,189	$ 136,669
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid for interest	$ 127,668	$ 63,170	$ 65,513
Cash paid for income taxes	$ —	$ 350	$ 315
SUPPLEMENTAL DISCLOSURE OF NON-CASH ACTIVITIES:			
Asset retirement obligations incurred, including changes in estimate	$ 2,111	$ 15,428	$ (6,646)
(Reductions) additions to oil and natural gas properties - change in capital accruals	$ (25,455)	$ 118,145	$ (9,831)
Additions to other property and equipment funded by capital lease borrowings	$ 2,180	$ 3,904	$ 2,758
Net premiums (paid) received on options that settled during the period	$ (71,566)	$ (37,103)	$ 31,757
Common stock issued for oil and natural gas properties	$ —	$ 1,183,501	$ —

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

NOTE 1. ORGANIZATION AND NATURE OF OPERATIONS

Parsley Energy, Inc. (either individually or together with its subsidiaries, as the context requires, the "Company") is an independent oil and natural gas company focused on the acquisition, development, exploration and production of unconventional oil and natural gas properties in the Permian Basin. The Permian Basin is located in west Texas and southeastern New Mexico and is characterized by high oil and liquids-rich natural gas content, multiple vertical and horizontal target horizons, extensive production histories, long-lived reserves and historically high drilling success rates. The Company's properties are located in two sub areas of the Permian Basin, the Midland Basin and the Delaware Basins, where, given the associated returns, it focuses predominantly on horizontal development drilling.

Double Eagle Acquisition

On April 20, 2017, the Company, and its subsidiary, Parsley Energy LLC ("Parsley LLC"), completed the acquisition (the "Double Eagle Acquisition") of all of the interests in Double Eagle Lone Star LLC, DE Operating LLC, and Veritas Energy Partners, LLC (which were subsequently renamed Parsley DE Lone Star LLC, Parsley DE Operating LLC, and Parsley Veritas Energy Partners, LLC, respectively) from Double Eagle Energy Permian Operating LLC ("DE Operating"), Double Eagle Energy Permian LLC ("DE Permian"), and Double Eagle Energy Permian Member LLC (together with DE Operating and DE Permian, "Double Eagle"), as well as certain related transactions with an affiliate of Double Eagle. The aggregate purchase price for the Double Eagle Acquisition consisted of approximately (i) $1,395.6 million in cash and (ii) 39,848,518 units of Parsley LLC ("PE Units") and a corresponding 39,848,518 shares of the Company's Class B common stock, par value $0.01 per share ("Class B common stock"). The Double Eagle Acquisition is discussed in further detail in *Note 6—Acquisitions of Oil and Natural Gas Properties.*

Public Offerings of Class A Common Stock

During 2016, the Company entered into multiple underwriting agreements to sell a total of 38,812,500 shares of Class A common stock (including 5,062,500 shares issued pursuant to the underwriters' option to purchase additional shares) in multiple underwritten public offerings (the "2016 Equity Offerings"). The 2016 Equity Offerings resulted in gross proceeds to the Company of approximately $962.2 million and net proceeds to the Company, after deducting underwriting discounts and commissions and offering expenses, of approximately $930.3 million. The Company used a portion of the net proceeds to fund certain acquisitions of oil and natural gas interests and the remaining net proceeds to fund a portion of its capital program and for general corporate purposes, including acquisitions.

During 2017, the Company entered into multiple underwriting agreements to sell a total of 66,700,000 shares of Class A common stock (including 8,700,000 shares issued pursuant to the underwriters' option to purchase additional shares) in multiple underwritten public offerings (the "2017 Equity Offerings"). The 2017 Equity Offerings resulted in gross proceeds to the Company of approximately $2,168.9 million and net proceeds to the Company, after deducting underwriting discounts and commissions and offering expenses, of approximately $2,123.5 million. As discussed in *Note 6—Acquisitions of Oil and Natural Gas Properties*, a portion of the net proceeds was used to fund the cash portion of the purchase price for the Double Eagle Acquisition, a portion of the net proceeds was used to fund certain other acquisitions of oil and natural gas interests, and the remaining net proceeds were used to fund a portion of its capital program and for general corporate purposes.

NOTE 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

These consolidated financial statements include the accounts of (i) the Company, (ii) Parsley LLC, (iii) the direct and indirect wholly owned subsidiaries of Parsley LLC, and (iv) Pacesetter Drilling, LLC ("Pacesetter"), an indirect, majority owned subsidiary of Parsley LLC, of which Parsley LLC owns, indirectly, a 63.0% interest. Parsley LLC also owns, indirectly, a 42.5% noncontrolling interest in Spraberry Production Services, LLC ("SPS"). The Company accounts for its investment in SPS using the equity method of accounting. All significant intercompany and intra-company balances and transactions have been eliminated.

Use of Estimates

These consolidated financial statements and related notes are presented in accordance with GAAP. Preparation in accordance with GAAP requires the Company to (i) adopt accounting policies within accounting rules set by the Financial Accounting Standards Board ("FASB") and by the SEC and (ii) 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. The Company's management believes the major estimates and assumptions impacting the Company's consolidated financial statements are the following:

- estimates of proved reserves of oil and natural gas, which affect the calculations of depletion, depreciation and amortization ("DD&A") and impairment of capitalized costs of oil and natural gas properties;
- estimates of the fair value of oil and natural gas properties the Company owns, particularly properties that the Company has not yet explored, or fully explored, by drilling and completing wells;
- impairment of developed and undeveloped properties and other assets;
- depreciation of property and equipment;
- valuation of commodity derivative instruments.

Although management believes these estimates are reasonable, actual results may differ from estimates and assumptions of future events and these revisions could be material. Future production may vary materially from estimated oil and natural gas proved reserves. Actual future prices may vary significantly from price assumptions used for determining proved reserves and for financial reporting.

Cash and Cash Equivalents

The Company considers all cash on hand, depository accounts held by banks, money market accounts and investments with an original maturity of three months or less to be cash equivalents. The Company's cash and cash equivalents are held in financial institutions in amounts that exceed the insurance limits of the Federal Deposit Insurance Corporation. However, management believes that the Company's counterparty risks are minimal based on the reputation and history of the institutions selected.

Short-term Investments

Periodically, the Company invests in commercial paper 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 three months at the date of purchase; otherwise, investments are reflected as short-term investments in the accompanying consolidated balance sheets based on their maturity dates. As of December 31, 2018, the Company had no short-term investments.

Accounts Receivable

Accounts receivable consist of receivables from joint interest owners on properties the Company operates and crude oil, natural gas and NGLs production delivered to purchasers. The purchasers remit payment for production directly to the Company. Most payments are received within three months after the production date. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Accounts receivable outstanding longer than the contractual payment terms are considered past due.

The Company recognizes an allowance for doubtful accounts in an amount equal to anticipated future uncollectible receivables. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the debtor's current ability to pay its obligation to the Company, the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. The Company had an allowance for doubtful accounts of $2.8 million at December 31, 2018. No allowance was deemed necessary at December 31, 2017.

Significant Customers

For the years ended December 31, 2018, 2017 and 2016, the following customers accounted for more than 10% of the Company's revenue:

	Year Ended December 31,		
	2018	2017	2016
Shell Trading (US) Company	53%	62%	44%
Lion Oil, Inc.	22%	3%	—%
Targa Pipeline Mid-Continent, LLC	11%	13%	13%
BML, Inc.	1%	2%	13%

The Company does not require customers to post collateral and does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Successful Efforts Method of Accounting

Proved Oil and Natural Gas Properties

Oil and natural gas exploration, development and production activities are accounted for in accordance with the successful efforts method of accounting. Under this method, costs of acquiring properties, costs of drilling successful exploration wells and development costs are capitalized.

As exploration and development work progresses and the reserves on these properties are proven, capitalized costs attributed to the properties and mineral interests are subject to DD&A. Depletion of capitalized costs is provided using the units-of-production method based on proved oil and gas reserves related to the associated reservoir.

Exploration and abandonment costs, other than exploration drilling costs, are charged to expense as incurred. These costs include seismic expenditures and other geological and geophysical costs, exploratory dry holes, impairment and amortization of unproved leasehold costs and lease rentals. The costs of exploratory wells and exploratory-type stratigraphic wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a 12-month period after drilling is complete.

The following table summarizes exploration and abandonment costs incurred by the Company for the periods indicated (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Leasehold abandonments and impairments	$ 160,834	$ 32,872	$ 6,063
Geological and geophysical costs	1,479	5,429	3,015
Unproved leasehold amortization	226	1,044	549
Total exploration and abandonment costs	$ 162,539	$ 39,345	$ 9,627

On the sale of a complete or partial unit of a proved property or pipeline and related facilities, the company determines the impact to the unit-of-production amortization rate. If the impact to the unit-of-production amortization rate is considered significant, the cost and related accumulated DD&A are removed from the property accounts and any gain or loss is recognized. If the impact to the unit-of-production amortization rate is not significant, the sale is accounted for as a normal retirement with no gain or loss recognized.

For sales of all of the Company's working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of less than all of the

Company's working interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

Unproved Oil and Natural Gas Properties

Unproved properties consist of costs incurred to acquire unproved leases, or lease acquisition costs. Unproved lease acquisition costs are capitalized until reclassified from unproved properties to proved properties when proved reserves are discovered on or otherwise attributed to the property or are expensed as the leases expire or the Company specifically identifies leases that are probable of reverting to the lessor. At December 31, 2018, the Company had $3.0 billion of undeveloped leasehold. Of the remaining undeveloped leasehold costs at December 31, 2018, $419.8 million is scheduled to expire in 2019. The leasehold expiring in 2019 relates to areas in which the Company is actively drilling. If the Company's drilling is not successful, this leasehold could become partially or entirely impaired.

Oil and Natural Gas Reserves

The estimates of proved oil and natural gas reserves utilized in the preparation of the consolidated financial statements are estimated in accordance with the rules established by the SEC and the FASB. These rules require that reserve estimates be prepared under existing economic and operating conditions using a trailing first day of the month 12-month average price, net of historical differentials, with no provision for price and cost escalations in future years except by contractual arrangements.

Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. Oil and gas properties are depleted by field using the units-of-production method. Capitalized drilling and development costs of producing oil and natural gas properties are depleted over proved developed reserves and leasehold costs are depleted over total proved reserves. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above, may be increased or decreased. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

Impairment of Long-Lived Assets, Including Proved Oil and Natural Gas Properties

The Company reviews its long-lived assets to be held and used, including proved oil and natural gas properties by field. 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 related to proved properties in the applicable field is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset. The Company reviews its oil and natural gas properties by amortization base or by individual well for those wells not constituting part of an amortization base. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value (discounted future cash flows) of the properties would be recognized at that time. Estimating future cash flows involves the use of judgments, including estimation of the proved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs. See *Note 14—Disclosures about Fair Value of Financial Instruments* for additional information regarding the Company's impairment of proved oil and natural gas properties.

Impairment of Unproved Oil and Natural Gas Properties

Unproved oil and natural gas properties are assessed periodically for impairment on a property by property basis by considering future drilling plans, the results of exploration activities, commodity price outlooks, planned future sales, remaining lease terms and the expiration of all or a portion of such projects. The Company's periodic assessment also considers its ability to enter into leasehold exchange transactions that allow for higher concentrations of ownership and development. The Company recognizes impairment expense for unproved properties at the earlier of the time when the lease term has expired or management estimates the lease will expire before it is drilled, sold or traded. The impairment of unproved oil and natural gas properties is recorded in *Exploration and abandonment costs* in the Company's consolidated statement of operations. Based on this assessment, the Company expensed $127.0 million of undeveloped leasehold in the fourth quarter of 2018 related to the expected future abandonment of expiring acreage.

The Company considers the following factors in its assessment of the impairment of unproved properties:

- the remaining length of unexpired term under its leases;
- its ability to actively manage and prioritize its capital expenditures to drill wells on undeveloped leases or make payments to extend leases that may be close to expiration;
- its ability to exchange leasehold positions with other companies that allow for higher concentrations of ownership and development potential; and
- its ability to convey partial mineral ownership to other companies in exchange for their drilling of leases.

Allocation of Purchase Price in Acquisitions

As part of its business strategy, the Company regularly pursues the acquisition of oil and natural gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. The Company's most significant estimates in its allocation typically relate to the value assigned to future recoverable oil and natural gas reserves and unproved properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

Asset Retirement Obligations

For the Company, asset retirement obligations represent the future abandonment costs of tangible assets, namely the plugging and abandonment of wells and land remediation. The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred if a reasonable estimate of fair value can be made and the corresponding cost is capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period. If the liability is settled for an amount other than the recorded amount, the difference is recorded in *Other income (expense)* in the consolidated statements of operations.

Inherent to the present value calculation are numerous estimates, assumptions and judgments, including, but not limited to: the ultimate settlement amounts, inflation factors, credit-adjusted risk-free rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions affect the present value of the abandonment liability, the Company makes corresponding adjustments to both the asset retirement obligations and the related oil and natural gas property asset balance. These revisions result in prospective changes to DD&A expense and accretion of the discounted abandonment liability.

The following table summarizes the changes in the Company's asset retirement obligations for the periods indicated (in thousands):

	Year ended December 31,	
	2018	2017
Asset retirement obligations, beginning of year	$ 27,170	$ 11,392
Additional liabilities incurred	2,111	9,081
Dispositions of wells	(3,557)	(432)
Accretion expense	1,422	971
Liabilities settled upon plugging and abandoning wells	(262)	(189)
Revision of estimates	—	6,752
Liabilities related to assets held for sale	—	(405)
Asset retirement obligations, end of year	$ 26,884	$ 27,170

Other Property and Equipment, net

Other property and equipment is recorded at cost. The Company expenses maintenance and repairs in the period incurred. Upon retirements or dispositions of assets, the cost and related accumulated depreciation are removed from the consolidated balance sheet with the resulting gains or losses, if any, reflected in operations. Depreciation of other property and equipment is computed using the straight line method over their estimated useful lives, which range from three years to 30 years. Depreciation expense on other property and equipment was $15.5 million, $11.5 million and $6.6 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Materials and supplies are stated at the lower of cost or market and consist of oil and gas drilling or repair items such a tubing, casing and pumping units. These items are primarily acquired for use in future drilling or repair operations and are carried at lower of cost or market. “Market,” in the context of valuation, represents net realizable value, which is the amount that the Company is allowed to bill to the joint account under joint operating agreements to which the Company is a party. The Company evaluated materials and supplies based on current operations and determined that these materials and supplies would not be utilized in the current year and included them in noncurrent assets as non-depreciable other property, plant and equipment. See *Note 14—Disclosures about Fair Value of Financial Instruments* for additional information regarding the Company’s impairment of materials and supplies.

Capitalized Interest

The Company capitalizes interest on expenditures made in connection with long-term projects that are not subject to current depletion. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use and only to the extent the company has incurred interest expense.

Equity Investments

Equity investments in which the Company exercises significant influence but does not control are accounted for using the equity method. Under the equity method, the Company’s share of investees’ earnings or loss, after elimination of intra-company profit or loss, is generally recognized in the consolidated statement of operations. The Company reviews its investments to determine if a non-temporary loss in value has occurred. If such loss has occurred, the Company would recognize an impairment provision. The Company did not recognize impairment for its equity investments during the years ended December 31, 2018, 2017 and 2016.

Derivative Instruments

The Company utilizes derivative financial instruments, including put spread options, three-way collars, commodity swap contracts and basis swap contracts, to (i) reduce the effect of price volatility on the Company’s oil and natural gas revenues and (ii) support our annual capital budgeting and expenditure plans.

The Company reports the fair value of derivatives on the consolidated balance sheets in derivative instrument assets and derivative instrument liabilities as either current or noncurrent. The Company determines the current and noncurrent classification based on the timing of expected future cash flows of individual transactions. The Company reports these on a gross basis by contract.

The Company’s derivative instruments were not designated as hedges for accounting purposes for any of the periods presented. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses resulting from the changes in fair value of derivatives are included in cash flows from operating activities.

Fair Value of Financial Instruments

Fair value represents the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the reporting date. The Company’s assets and liabilities that are measured at fair value at each reporting date are classified according to a hierarchy that prioritizes inputs and assumptions underlying the valuation techniques. This fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs and consists of three broad levels:

Level 1: Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.

Level 2: Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1 that are either directly or indirectly observable as of the reporting date.

Level 3: Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

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

Deferred Loan Costs

Deferred loan costs are stated at cost, net of amortization, and are amortized to interest expense using the effective interest method over the life of the loan.

Revenue Recognition

Substantially all of the Company’s revenue is from the sale of crude oil, natural gas and NGLs. See *Note 3—Revenue from Contracts with Customers* for additional information regarding the Company’s revenue recognition.

Defined Contribution Plan

The Company sponsors a 401(k) defined contribution plan for the benefit of all employees beginning on their date of hire. The plan allows eligible employees to contribute a portion of their annual compensation, not to exceed annual limits established by the federal government. The Company makes matching contributions of up to a certain percentage of an employee’s contributions. For the years ended December 31, 2018, 2017 and 2016, the Company made contributions to the plan of $3.8 million, $2.8 million and $1.9 million, respectively.

Income Taxes

The Company accounts for income taxes using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are calculated by applying existing tax laws and the rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. The tax returns and the amount of taxable income or loss are subject to examination by federal and state taxing authorities.

The Company periodically assesses whether it is more likely than not that it will generate sufficient taxable income to realize its deferred income tax assets, including net operating losses. In making this determination, the Company considers all available positive and negative evidence and makes certain assumptions. The Company considers, among other things, its deferred tax liabilities, the overall business environment, its historical earnings and losses, current industry trends and its outlook for future years.

Earnings per Share

The Company uses the "if-converted" method to determine the potential dilutive effect of its Class B common stock and the treasury stock method to determine the potential dilutive effect of outstanding restricted stock and restricted stock units.

Comprehensive Income

The Company has no elements of comprehensive income other than net income.

Segment Reporting

Operating segments are defined as components of an enterprise (i) that engage in activities from which it may earn revenues and incur expenses and (ii) for which separate operational financial information is available and is regularly evaluated by the chief operating decision maker for the purpose of allocating resources and assessing performance.

Based on the organization and management of the Company, the Company has only one reportable operating segment, which is oil and natural gas exploration and production. The Company considers drilling rig services ancillary to its oil and gas exploration and production activities and manages these services to support such activities.

Reclassifications

Certain reclassifications have been made to prior period amounts to conform to the current presentation.

Recent Accounting Pronouncements

Recently Adopted Accounting Pronouncements

In May 2014, the FASB issued Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers, which supersedes the revenue recognition requirements in Accounting Standards Codification ("ASC") Topic 605, Revenue Recognition ("ASC 605"), and most industry-specific guidance. The Company adopted this standard effective January 1, 2018 using the modified retrospective approach. As a result, the Company changed its accounting policy for revenue recognition, as discussed in *Note 3—Revenue from Contracts with Customers*. The Company also implemented processes and controls to ensure new contracts are reviewed for the appropriate accounting treatment and to generate the required disclosures under the standards.

In January 2016, the FASB issued no. ASU 2016-01, *Financial Instruments-Overall*, as an amendment to ASC Subtopic 825-10. The amendments in this update address certain aspects of recognition, measurement, presentation and disclosure of financial instruments. Among other items, this update will simplify the impairment assessment of equity investments without readily determinable fair values by requiring a qualitative assessment to identify impairment. When a qualitative assessment indicates that impairment exists, an entity is required to measure the investment at fair value. This impairment assessment reduces the complexity of the other-than-temporary impairment guidance that certain entities follow. The Company adopted ASU 2016-01 as of January 1, 2018. The adoption of this guidance did not have a material effect on the Company's financial position, results of operation or cash flows.

In November 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows (Topic 230)*, which requires that a statement of cash flows explain the total change during the period in cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. The amounts generally described as restricted cash or restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statements of cash flows. The amended guidance will be effective for the Company for annual periods beginning after December 15, 2017. The amendments should be applied using a retrospective transition method to each period presented. Early adoption is permitted for any entity in any interim or annual period. The Company implemented the new guidance on January 1, 2018 and disclosure revisions have been made for the periods presented on the consolidated statements of cash flows. The Company's consolidated statements of cash flows for the years ended December 31, 2017 and 2016 were adjusted to conform to this guidance, which resulted in a decrease in cash flows from operating activities of $3.3 million and an increase in cash flows from operating activities of $2.1 million, respectively.

In March 2018, the FASB issued ASU 2018-05, *Income Taxes (Topic 740)*, which amends certain guidance in ASC 740, Income Taxes, to reflect Staff Accounting Bulletin No. 118, which provides guidance for companies that are not able to complete their accounting for the income tax effects of the Tax Act during the period of enactment. This guidance also includes amendments to the XBRL Taxonomy. For public business entities, the amendments in ASU 2018-05 are effective for fiscal years ending after December 15, 2020. Early adoption is permitted. The Company has prepared its consolidated financial statements for the years ended December 31, 2018 and 2017 in accordance with ASU 2018-05. To account for the effects of the Tax Act, during the year ended December 31, 2017, the Company remeasured its deferred tax assets and liabilities based on the federal income and state income tax rates at which they are now expected to reverse, and they now generally reflect a federal income tax rate of 21%. The enacted rate change resulted in a noncash increase of approximately $23.9 million to the Company's income tax provision, a corresponding reduction of $23.9 million to the Company's net noncurrent deferred tax asset balance and a reduction in valuation allowance of $24.3 million. There were no adjustments recorded to these estimates during the year ended December 31, 2018.

Recently Issued but Not Yet Adopted Accounting Pronouncements

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)*, which requires lessees to recognize leases on-balance sheet and disclose key information about leasing arrangements. Topic 842 was subsequently amended by ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842*; ASU No. 2018-10, *Codification Improvements to Topic 842*, *Leases*; ASU No. 2018-11, *Targeted Improvements*; and ASU No. 2018-20 *Leases (Topic 842)*. The new standard establishes a right-of-use model (ROU) that requires a lessee to recognize a ROU asset and lease liability on the balance sheet for all leases with a term longer than 12 months. Leases will be classified as finance or operating, with classification affecting the pattern and classification of expense recognition in the income statement.

The new standard was effective for the Company on January 1, 2019, with early adoption permitted. A modified retrospective transition approach is required, applying the new standard to all leases existing at the date of initial application. An entity may choose to use either (1) its effective date or (2) the beginning of the earliest comparative period presented in the financial statements as its date of initial application. If an entity chooses the second option, the transition requirements for existing leases also apply to leases entered into between the date of initial application and the effective date. The entity must also recast its comparative period financial statements and provide the disclosures required by the new standard for the comparative periods. The Company adopted the new standard on January 1, 2019 and used the effective date as the Company's date of initial application. As a result, financial information will not be updated and the disclosures required under the new standard will not be provided for dates and periods before January 1, 2019.

The new standard provides a number of optional practical expedients in transition. The Company has elected to apply the practical expedient to use hindsight with respect to determining lease term and in assessing any impairment of right-of-use assets for existing leases. The Company did not elect to apply the "package practical expedients."

The Company has determined that this standard will have a material effect on the Company's financial statements. While the Company continues to assess all of the effects of adoption, the Company believes the most significant effects relate to (1) the recognition of new ROU assets and lease liabilities on its balance sheet for its non-cancelable lease contracts, including drilling rigs, real estate, field and office equipment operating leases; and (2) providing significant new disclosures about its leasing activities. The Company did not expect a significant change in its leasing activities between now and adoption.

On adoption, the Company expects to recognize additional operating liabilities ranging from $145.0 million to $155.0 million, with corresponding ROU assets based on the present value of the remaining minimum rental payments under current leasing standards for existing operating leases.

The new standard also provides practical expedients for an entity's ongoing accounting. The Company elected the short-term lease recognition exemption for all leases that qualify. This means, for those leases that qualify, the Company did not recognize ROU assets or lease liabilities, and this includes not recognizing ROU assets or lease liabilities for existing short-term leases of those assets in transition. The Company will elect the practical expedient to not separate lease and non-lease components for all of its leases other than leases of vehicles.

NOTE 3. REVENUE FROM CONTRACTS WITH CUSTOMERS

Impact of ASC Topic 606 Adoption

The Company's adoption of ASC Topic 606, *Revenue from Contracts with Customers* ("ASC 606"), resulted in the following adjustments for the year ended December 31, 2018 (in thousands):

	Year Ended December 31, 2018		
	ASC 605	Adjustment	ASC 606
Revenues			
Oil sales	$ 1,536,244	$ —	$ 1,536,244
Natural gas sales [(1)]	45,032	6,199	51,231
Natural gas liquids sales [(1)]	200,898	26,374	227,272
Total production revenues	1,782,174	32,573	1,814,747
Operating expenses			
Transportation and processing costs	—	32,573	32,573
Production revenues less transportation and processing costs	$ 1,782,174	$ —	$ 1,782,174
Net income attributable to Parsley Energy, Inc. stockholders	$ 369,127	$ —	$ 369,127

(1) Revenues associated with natural gas and NGLs sales at the plant inlet are considered a single combined performance obligation. The applicable line items include $13.6 million and $59.5 million of natural gas and NGLs sales, respectively, completed at the plant inlet.

Changes to natural gas and NGLs sales were made in accordance with the new control model defined in ASC 606. Under the new control model, the Company was required to identify and separately analyze each contract associated with revenues to determine the appropriate accounting application. The Company considered various indicators for contracts and the weighting of their relevance to determine when control transferred to the customer (such as whether raw gas is sold at the receipt point or residue gas and NGLs are sold at the tailgate of the gas processing plants). Based on this analysis, the Company concluded that the presence of product redelivery and take-in-kind rights, if substantive, are determinative indicators of control transferring at the tailgate if there is intent at contract inception. Additionally, the Company considers risk of loss an important indicator of when control transfers, which is comprised of risks associated with loss of product, exposure to product mix and recoveries, and exposure to index prices versus actual prices. The Company concluded that title, custody, and acceptance are not determinative indicators of control, as such factors may be present in the case of a sale or the performance of a service.

As a result of this analysis, the Company modified its accounting and presentation of natural gas and NGLs sales, and transportation and processing costs under certain marketing agreements. This is due to the conclusion that the Company represents the principal and the ultimate third party is its customer, which implies that the Company maintains control of the product through the tailgate of gas processing plants in certain natural gas processing and marketing agreements with certain midstream entities in accordance with the control model in ASC 606. This is a change from previous conclusions reached by the Company for these agreements, when utilizing the principal versus agent indicators under ASC 605, where the Company acted as the agent and the midstream processing company acted as its customer. As a result, the Company modified its presentation of revenues and expenses for these agreements. Revenues related to these agreements are now presented on a gross basis for amounts expected to be received from third-party customers through the marketing process. Transportation and processing costs related to these agreements, incurred prior to the transfer of control to the customer at the tailgate of the natural gas processing facilities, are now presented as *Transportation and processing costs* on the Company's consolidated statements of operations.

Certain of the Company's contracts for the sale of commodities contain embedded derivatives. The Company has elected to utilize the normal purchases and normal sales scope exception as provided by ASC Topic 815, *Derivatives and Hedging*.

Revenue from Contracts with Customers

Revenue is measured based on considerations specified in contracts with customers, excluding any sales incentives or amounts collected on behalf of third parties. The Company recognizes revenue when a performance obligation is satisfied by the transfer of control over a product to the ultimate customer. Sales of oil, natural gas and NGLs are recognized at the time that control of the product is transferred to the customer and collectability is reasonably assured. Generally, the pricing provisions in the Company's contracts are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, the quality of the oil or natural gas, and prevailing supply and demand conditions. As a result, the prices of the Company's oil, natural gas and NGLs fluctuate to remain competitive with other available oil, natural gas and NGLs supplies. The Company reports revenues disaggregated by product on its consolidated statements of operations.

Oil Sales

Oil production is sold at the wellhead and the Company collects an agreed-upon index price, net of pricing differentials. In this scenario, revenue is recognized when control transfers to the purchaser at the wellhead at the net price received by the Company.

Natural Gas and NGLs Sales

Under the Company's natural gas processing contracts, it delivers natural gas to a midstream processing company at the wellhead or the inlet of the midstream processing company's system. The midstream processing company gathers and processes the natural gas and remits proceeds to the Company for the resulting natural gas and NGLs sales. In these scenarios, the Company evaluates whether it is the principal or the agent in the transaction, which includes considerations of product redelivery, take-in-kind rights and risk of loss. For those contracts where the Company has concluded that control of the product transfers at the tailgate of the plant, meaning that the Company is the principal and the ultimate third party is its customer, the Company recognizes revenue on a gross basis, with transportation and processing fees presented as *Transportation and processing costs* on the Company's consolidated statements of operations. Alternatively, for those contracts where the Company has concluded control of the product transfers at the inlet of the plant, meaning that the Company is the agent and the midstream processing company is the Company's customer, the Company recognizes natural gas and NGLs sales based on the net amount of proceeds received from the midstream processing company. The Company also determined that losses associated with shrinkage and line loss ("FL&U") occur prior to the change in control. As a result, natural gas and NGLs sales are presented net of FL&U costs.

Production Imbalances

Previously, the Company elected to utilize the entitlements method, which is no longer applicable, to account for natural gas production imbalances. The Company now utilizes the sales method to account for natural gas production imbalances; if the Company sells natural gas to a customer in excess of its entitled share of production, the Company is required to perform a principal versus agent analysis to determine whether it should record the gross amount of revenue and transportation and processing costs equal to the other owners' interests or recognize the net amount of revenue. In conjunction with the adoption of ASC 606, for the year ended December 31, 2018, there was no material impact to the financial statements due to this change in accounting for production imbalances.

Transaction Price Allocated to Remaining Performance Obligations

A significant number of the Company's product sales are short-term in nature, with a contract term of one year or less. For these contracts, the Company has utilized the practical expedient in ASC 606-10-50-14, which exempts the Company from the requirements to disclose the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient in ASC 606-10-50-14(a), which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Contract Balances

Under the Company's product sales contracts, the Company invoices customers once performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's product sales contracts do not give rise to contract assets or liabilities under ASC 606.

Prior-Period Performance Obligations

The Company records revenue in the month production is delivered to the purchaser. Settlement statements for certain natural gas and NGLs sales, however, may not be received for 30 to 90 days after the date production is delivered, and as a result the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. In these situations, the Company records the differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. The Company has existing internal controls for its revenue estimation process and related accruals, and any identified differences between the Company's revenue estimates and actual revenue received have historically been insignificant. For the years ended December 31, 2018, 2017 and 2016, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

NOTE 4. DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Derivative Instruments and Concentration of Risk

Objective and Strategy

The Company utilizes derivative financial instruments, including put spread options, three-way collars, commodity swap contracts and basis swap contracts, to (i) reduce the effect of price volatility on the Company's oil and natural gas revenues and (ii) support the Company's annual capital budgeting and expenditure plans.

The Company uses put spread options and collars to manage commodity price risk for NYMEX WTI. A put spread option is a combination of two options: a purchased put and a sold put. The purchased put establishes the minimum price that the Company will receive for the contracted volumes unless the market price for the commodity falls below the sold put strike price, at which point the minimum price equals the reference price plus the excess of the purchased put strike price over the sold put strike price. A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be the NYMEX index price plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (ceiling) the Company will receive for the volumes under contract.

Additionally, the Company uses basis swap contracts to mitigate basis risk caused by the volatility of the Company's basis differentials. The oil basis swap contracts establish the differential between Cushing WTI prices and the relevant price index at which oil production is sold. Natural gas basis swaps establish the differential Henry Hub prices and the relevant price index at which oil production is sold.

Oil Production Derivative Activities

The Company's material physical sales contracts governing its oil production are typically correlated with NYMEX WTI, including Cushing ("WTI Cushing"), Midland ("WTI Midland") and Magellan East Houston ("WTI MEH") oil prices. The Company uses put spread options and three-way collars to manage oil price volatility. The Company uses basis swap contracts to reduce basis risk between NYMEX WTI prices and the actual index prices at which the oil is sold.

As of December 31, 2018, the Company had the following outstanding oil derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

Put spreads (1)	Year Ending December 31, 2019			Year Ending December 31, 2020
	WTI Cushing	WTI Midland	WTI MEH	WTI MEH
Volume (MBbls)	6,300	3,300	2,100	900
Long put price (per Bbl)	$ 57.02	$ 53.18	$ 65.71	$ 70.00
Short put price (per Bbl)	$ 47.98	$ 43.18	$ 55.71	$ 60.00

Three-way collars	Year Ending December 31, 2019
	WTI Cushing
Volume (MBbls)	5,400
Short call price (per Bbl)	$ 75.52
Long put price (per Bbl)	$ 50.00
Short put price (per Bbl)	$ 41.11

	Year Ending December 31, 2019	
	Volume (MBbls)	Fixed Price Swap (per Bbl)
Basis swap - Midland-Cushing index (2)	3,960	$ 8.07
Basis swap - Houston-Cushing index (2)	780	$ 5.10

(1) Excludes 6,000 notional MBbls with a fair value of $25.0 million related to amounts recognized under master netting agreements with derivative counterparties.

(2) Represents swaps that fix the basis differentials between the index prices at which the Company sells its oil and the Cushing WTI price.

Natural Gas Production Derivative Activities

All material physical sales contracts governing the Company’s natural gas production are tied directly or indirectly to NYMEX Henry Hub natural gas prices or regional index prices where the natural gas is sold. The Company uses three-way collars and commodity swap contracts to manage natural gas price volatility.

The following table sets forth the volumes associated with the Company's outstanding natural gas derivative contracts expiring during the periods indicated and the weighted average natural gas prices for those contracts:

	Year Ending December 31, 2019
Three-Way Collars	**NYMEX Henry Hub**
Volume (MMbtu)	12,000,000
Short put price (per MMbtu)	$ 3.00
Long put price (per MMbtu)	$ 2.50
Short call price (per MMbtu)	$ 3.93

	Year Ending December 31, 2019	
	Volume (MMbtu)	Fixed Price Swap (per MMbtu)
Basis swap - Waha [1]	7,200,000	$ 2.00

(1) Represents swaps that fix the basis differentials between the index prices at which the Company sells its natural gas produced in the Permian Basin and NYMEX Henry Hub price.

Effect of Derivative Instruments on the Consolidated Financial Statements

All of the Company's derivatives are accounted for as non-hedge derivatives and therefore all changes in the fair values of its derivative contracts are recognized as gains or losses in the earnings of the periods in which they occur. The table below summarizes the Company's gains (losses) on derivative instruments for the years ended December 31 2018, 2017 and 2016 (in thousands):

	Year Ending December 31,		
	2018	2017	2016
Changes in fair value of derivative instruments	$ 42,258	$ (81,805)	(77,276)
Net derivative settlements	8,084	15,670	26,441
Gain (loss) on derivatives	$ 50,342	$ (66,135)	$ (50,835)
Net premiums on options that settled during the period [1]	$ 71,566	$ 37,103	$ 31,757

(1) The net premiums on options that settled during the period represents the cumulative cost of premiums paid and received on positions purchased and sold, which expired during the current period. These amounts are included in *Gain (loss) on derivatives* on the Company's consolidated statement of operations.

The Company classifies the fair value amounts of derivative assets and liabilities as gross current or noncurrent derivative assets or gross current or noncurrent derivative liabilities, whichever the case may be, excluding those amounts netted under master netting agreements. The fair value of the derivative instruments is discussed in *Note 14—Disclosures about Fair Value of Financial Instruments.* The Company has agreements in place with all of its counterparties that allow for the financial right of offset for derivative assets and liabilities at settlement or in the event of default under the agreements. Additionally, the Company maintains accounts with its brokers to facilitate financial derivative transactions in support of its risk management activities. Based on the value of the Company's positions in these accounts and the associated margin requirements, the Company may be required to deposit cash into these broker accounts. During the years ended December 31, 2018, 2017 and 2016, the Company did not receive or post any material margins in connection with collateralizing its derivative positions.

The following table presents the Company's net exposure from its offsetting derivative asset and liability positions, as well as option premiums payable and receivable as of the reporting dates indicated (in thousands):

	Gross Amount	Netting Adjustments	Net Exposure
December 31, 2018			
Derivative assets with right of offset or master netting agreements	$ 236,431	$ (25,010)	$ 211,421
Derivative liabilities with right of offset or master netting agreements	(193,973)	25,010	(168,963)
December 31, 2017			
Derivative assets with right of offset or master netting agreements	$ 59,132	$ (1,443)	$ 57,689
Derivative liabilities with right of offset or master netting agreements	(106,986)	1,443	(105,543)

Concentration of Credit Risk

The Company believes that it has limited credit risk with respect to its exchange-traded contracts, as such contracts are subject to financial safeguards and transaction guarantees through NYMEX. Over-the-counter traded options expose the Company to counterparty credit risk. These over-the-counter options are entered into with large multinational financial institutions with investment grade credit ratings or through brokers that require all the transaction parties to collateralize their open option positions. The gross and net credit exposure from the Company's commodity derivative contracts as of December 31, 2018 and 2017 is summarized in the preceding table.

The Company monitors the creditworthiness of its counterparties, establishes credit limits according to the Company's credit policies and guidelines and assesses the impact on fair values of its counterparties' creditworthiness. The Company typically enters into International Swap Dealers Association Master Agreements ("ISDA Agreements") with its derivative counterparties. The terms of the ISDA Agreements provide the Company and its counterparties and brokers with rights of net settlement of gross commodity derivative assets against gross commodity derivative liabilities. The Company routinely exercises its contractual right to offset realized gains against realized losses when settling with derivative counterparties. If the Company believes a counterparty's creditworthiness has declined or is suspect, it may seek to novate the applicable ISDA Agreement to another financial institution that has an ISDA Agreement in place with the Company. The Company did not incur any losses due to counterparty nonperformance during any of the years ended December 31, 2018, 2017 or 2016.

Credit Risk Related Contingent Features in Derivatives

Certain commodity derivative instruments contain provisions that require the Company to either post additional collateral or collateral support (including letters of credit, security interests in an asset, or a performance bond or guarantee), or immediately settle any outstanding liability balances, upon the occurrence of a specified credit risk related event. These events, which are set forth in the Company's existing commodity derivative contracts, include, among others, downgrades in the credit ratings of the Company and its affiliates, events of default under the Company's Revolving Credit Agreement (as defined in *Note 8—Debt*), and the release of collateral (other than as provided under the terms of the Revolving Credit Agreement). Although the Company could be required to post additional collateral or collateral support, or immediately settle any outstanding liability balances, under such conditions, the Company seeks to reduce its potential risk by entering into commodity derivative contracts with several different counterparties. None of the Company's commodity derivative instruments, excluding net premiums payable, were in a net liability position with respect to any individual counterparty at December 31, 2018 or 2017.

NOTE 5. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment includes the following (in thousands):

	December 31, 2018	December 31, 2017
Oil and natural gas properties:		
Subject to depletion	$ 6,659,444	$ 4,492,802
Not subject to depletion		
Incurred in 2018	677,920	—
Incurred in 2017	1,726,591	2,837,766
Incurred in 2016 and prior	884,291	1,220,746
Total not subject to depletion	3,288,802	4,058,512
Oil and natural gas properties, successful efforts method	9,948,246	8,551,314
Less accumulated depreciation, depletion and impairment	(1,295,098)	(822,459)
Total oil and natural gas properties, net	8,653,148	7,728,855
Other property, plant and equipment	206,662	131,115
Less accumulated depreciation	(35,923)	(24,528)
Other property, plant and equipment, net	170,739	106,587
Total property, plant and equipment, net	$ 8,823,887	$ 7,835,442

Costs subject to depletion are proved costs and costs not subject to depletion are unproved costs and current drilling projects. At December 31, 2018 and 2017, the Company had excluded $3,288.8 million and $4,058.5 million of capitalized costs from depletion.

As the Company's exploration and development work progresses and the reserves on the Company's properties are proven, capitalized costs attributed to the properties and mineral interests are subject to DD&A. Depletion of capitalized costs is provided using the units-of-production method based on proved oil and natural gas reserves related to the associated reservoir. Depletion expense on capitalized oil and natural gas properties was $569.7 million, $340.8 million and $227.2 million for the years ended December 31, 2018, 2017 and 2016, respectively. The Company had no exploratory wells in progress at December 31, 2018, 2017 or 2016.

Costs not subject to depletion primarily include leasehold costs, broker and legal expenses and capitalized internal costs associated with developing oil and natural gas prospects on these properties. Leasehold costs are transferred into costs subject to depletion on an ongoing basis as these properties are evaluated and proved reserves are established.

Costs not subject to depletion also include costs associated with development wells in progress or awaiting completion at year-end. These costs are transferred into costs subject to depletion on an ongoing basis as these wells are completed and proved reserves are established or confirmed. These costs totaled $275.3 million and $94.4 million at December 31, 2018 and 2017, respectively. The Company anticipates that the $275.3 million associated with the wells in progress at December 31, 2018 will be transferred to costs subject to depletion during 2019. The $94.4 million associated with the wells in progress at December 31, 2017 was transferred to costs subject to depletion during 2018.

The Company capitalizes interest on expenditures made in connection with long-term projects that are not subject to current depletion. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use and only to the extent the company has incurred interest expense. There was no capitalized interest recorded during the years ended December 31, 2018, 2017 or 2016.

NOTE 6. ACQUISITIONS OF OIL AND NATURAL GAS PROPERTIES

The Company incurred costs of $137.0 million, $194.5 million and $79.1 million related to the purchase of leasehold acreage during the years ended December 31, 2018, 2017 and 2016, respectively. During the years ended December 31, 2018, 2017 and 2016, the Company reflected $119.7 million, $176.5 million and $79.1 million as part of costs not subject to depletion, respectively. During the years ended December 31, 2018 and 2017, the Company reflected $17.3 million and $18.0

million as part of costs subject to depletion within its oil and natural gas properties, respectively. There were no such costs incurred during the year ended December 31, 2016.

In addition to the above described acquisition of leasehold acreage, during 2017, the Company acquired, from unaffiliated individuals and entities, interests in certain oil and natural gas properties through a number of separate, individually negotiated transactions, including the Double Eagle Acquisition (as defined in *Note 1—Organization and Nature of Operations*), for total consideration of $3,181.1 million. These acquisitions were accounted for using the acquisition method under ASC Topic 805, "Business Combinations," which requires the acquired assets and liabilities to be recorded at fair values as of the respective acquisition dates. The Company reflected $464.2 million of the total consideration paid as part of its costs subject to depletion within its oil and natural gas properties and $2,716.9 million, as unproved leasehold costs within its oil and natural gas properties for year ended December 31, 2017. Excluding the Double Eagle Acquisition, the revenues and operating expenses attributable to these acquisitions during the year ended December 31, 2017 were not material.

As described in *Note 1—Organization and Nature of Operations,* on April 20, 2017, the Company and Parsley LLC completed the Double Eagle Acquisition, as well as certain related transactions with an affiliate of Double Eagle. The aggregate consideration for the Double Eagle Acquisition, following post-closing adjustments, was $2,579.1 million, which consisted of (i) approximately $1,395.6 million in cash and (ii) 39,848,518 PE Units and a corresponding 39,848,518 shares of Class B common stock. Of the aggregate consideration transferred, approximately $172.3 million in cash and approximately 4,921,557 PE Units (and a corresponding approximately 4,921,557 shares of Class B common stock) were deposited in an indemnity holdback escrow account.

The following table summarizes the estimated fair value of the assets acquired and liabilities assumed as a result of the Double Eagle Acquisition (in thousands):

Cash	$	2,469
Receivables		20,756
Derivatives		3,970
Proved oil and natural gas properties		353,000
Unproved oil and natural gas properties		2,257,266
Total assets acquired		2,637,461
Accounts payable		(48,179)
Deferred tax liability		(10,167)
Total liabilities assumed		(58,346)
Estimated fair value of net assets acquired	$	2,579,115

During 2016, the Company acquired from unaffiliated individuals and entities, interests in certain oil and natural gas properties through a number of separate, individually negotiated transactions for total cash consideration of $1,267.1 million. The Company reflected $261.4 million of the total consideration paid as part of its costs subject to depletion and $1,005.7 million as unproved leasehold costs within its oil and natural gas properties. The revenues and operating expenses attributable to the working interest acquisitions during the years ended December 31, 2018, 2017 and 2016 were not material.

During 2018, 2017 and 2016, the Company exchanged certain unproved acreage and oil and natural gas properties with a third party, with no gain or loss recognized.

NOTE 7. SALES OF OIL AND NATURAL GAS PROPERTIES

In 2018, the Company closed the sale of certain leasehold, surface and mineral acreage for proceeds of $34.4 million, subject to customary purchase price adjustments. The Company recognized a $5.2 million gain on the sale.

In 2018, the Company also closed sales of certain leasehold acreage for proceeds of $188.2 million, including customary purchase price adjustments. As of December 31, 2017, the Company classified certain of these assets as held for sale. Upon closing these sales, the Company recognized no gain or loss in accordance with the guidance for partial sales of oil and natural gas properties under ASC Topic 932, Extractive Activities—Oil and Gas.

In 2018, Pacesetter closed the sale of all of its physical assets for consideration equivalent to $13.1 million, consisting of $11.0 million in cash and a $2.1 million term loan that was repaid in the first quarter of 2019. Following the liquidation of Pacesetter, which is expected to take place in 2019, its remaining assets will be distributed to its members, including Parsley Energy Operations, LLC ("Parsley Energy Operations"), a wholly owned subsidiary of Parsley LLC. The Company recognized a $1.2 million gain on the sale.

In 2017, the Company sold 21,939 gross (7,476 net) acres for total proceeds of $30.5 million and recognized a $14.3 million loss on the divestitures.

In 2016, there was no such divestiture activity.

NOTE 8. DEBT

The Company's debt consists of the following (in thousands):

	December 31, 2018	December 31, 2017
Revolving Credit Agreement	$ —	$ —
6.250% senior unsecured notes due 2024	400,000	400,000
5.375% senior unsecured notes due 2025	650,000	650,000
5.250% senior unsecured notes due 2025	450,000	450,000
5.625% senior unsecured notes due 2027	700,000	700,000
Capital leases	4,202	4,906
Total debt	2,204,202	2,204,906
Debt issuance costs on senior unsecured notes	(22,918)	(26,341)
Premium on senior unsecured notes	2,796	3,312
Less: current portion	(2,413)	(2,352)
Total long-term debt	$ 2,181,667	$ 2,179,525

Revolving Credit Agreement

On October 28, 2016, the Company and its subsidiary Parsley LLC entered into a revolving credit agreement with, among others, Wells Fargo Bank, National Association, as administrative agent (the "New Revolving Credit Agreement"), providing for an initial borrowing base of $900.0 million and an initial commitment level of $600.0 million. The New Revolving Credit Agreement replaced the Company's previously existing revolving credit agreement, which was terminated concurrently with entry into the New Revolving Credit Agreement. As used in these consolidated financial statements, the term "Revolving Credit Agreement" refers, prior to October 28, 2016, to the previously existing credit agreement and, subsequent to October 28, 2016, to the New Revolving Credit Agreement.

The Revolving Credit Agreement provides for a five-year senior secured revolving credit facility, maturing on October 28, 2021, with a borrowing capacity equal to the lesser of (i) the borrowing base, (which currently stands at $2.3 billion), (ii) aggregate elected borrowing base commitments (which currently stands at $1.0 billion) and (iii) $2.5 billion. The Revolving Credit Agreement is secured by substantially all of Parsley LLC's and its restricted subsidiaries' assets.

As of December 31, 2018, the Revolving Credit Agreement, as amended to date, provides for a borrowing base of $2.3 billion, which is subject to scheduled annual and other elective redeterminations, with a commitment level of $1.0 billion. There were no borrowings outstanding and $8.7 million in letters of credit outstanding under the Revolving Credit Agreement as of December 31, 2018, resulting in availability of approximately $991.3 million. The amount Parsley LLC is able to borrow under the Revolving Credit Agreement is subject to compliance with the financial covenants, satisfaction of various conditions precedent to borrowing and other provisions of the Revolving Credit Agreement.

Borrowings under the Revolving Credit Agreement can be made in Eurodollars or at the alternate base rate. Eurodollar loans bear interest at a rate per annum equal to an adjusted LIBO rate plus an applicable margin ranging from 1.25% to 2.25%, depending on the percentage of the borrowing base utilized. Alternate base rate loans bear interest at a rate per annum equal to the greater of (i) the prime rate of Wells Fargo, (ii) the federal funds effective rate plus 0.5% and (iii) the adjusted LIBO rate plus 1.0%, plus an applicable margin ranging from 0.25% to 1.25%, depending on the percentage of the borrowing base utilized. The Revolving Credit Agreement also provides for a commitment fee ranging from 0.375% to 0.500%, depending on the percentage of the borrowing base utilized. As of December 31, 2018, letters of credit outstanding under the Revolving Credit Agreement had a weighted average interest rate of 1.50%. The Company may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

The Revolving Credit Agreement is subject to various financial covenants, which include, for example, the maintenance of the following financial ratios:

- a minimum current ratio (based on the ratio of consolidated current assets to consolidated current liabilities) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter; and
- a maximum consolidated leverage ratio of not more than 4.0 to 1.0 as of the last day of any fiscal quarter for the four fiscal quarters ending on such date.

The Revolving Credit Agreement places restrictions on Parsley LLC and certain of its subsidiaries with respect to, for example, additional indebtedness, liens, dividends and other payments, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters. The Revolving Credit Agreement also places customary "holding company" restrictions on the activities of the Company. In addition, the Revolving Credit Agreement is subject to customary events of default, including a change in control. If an event of default occurs and is continuing, the administrative agent or the Majority Lenders (as defined in the Revolving Credit Agreement) may accelerate any amounts outstanding and terminate lender commitments.

6.250% Senior Unsecured Notes due 2024

On May 27, 2016, Parsley LLC and Parsley Finance Corp. (the "Issuers") issued $200.0 million aggregate principal amount of 6.250% senior unsecured notes due 2024 (the "Initial 2024 Notes") in an offering that was exempt from registration under the Securities Act (the "Initial 2024 Notes Offering"). The Initial 2024 Notes Offering resulted in net proceeds to the Company, after deducting initial purchaser discounts and commissions and offering expenses, of approximately $195.4 million.

On August 19, 2016, the Issuers issued an additional $200.0 million aggregate principal amount of 6.250% senior notes due 2024 (the "New 2024 Notes" and together with the Initial 2024 Notes, the "2024 Notes") at 102.000% of par, plus accrued and unpaid interest from May 27, 2016, in an offering that was exempt from registration under the Securities Act (the "New 2024 Notes Offering"). The New 2024 Notes Offering resulted in gross proceeds to the Company of $206.8 million, including a $4.0 million premium and $2.8 million of accrued and unpaid interest and net proceeds to the Company, after deducting accrued and unpaid interest, initial purchaser discounts and commissions and offering expenses, of approximately $199.6 million. The interest received is included in *Accounts payable and accrued expenses* on the Company's consolidated balance sheets and as an operating activity on the consolidated statements of cash flows.

The New 2024 Notes were issued as additional notes under the indenture governing the Initial 2024 Notes. The New 2024 Notes have identical terms, other than the issue date, as the Initial 2024 Notes and the New 2024 Notes and the Initial 2024 Notes are treated as a single class of securities under the indenture governing the 2024 Notes. Interest is payable on the 2024 Notes semi-annually in arrears on each June 1 and December 1. The 2024 Notes are fully and unconditionally guaranteed on a senior unsecured basis by all of the subsidiaries of Parsley LLC that guarantee the indebtedness under the Revolving Credit Agreement, other than Parsley Finance Corp. (the "Guarantor Subsidiaries"). The 2024 Notes are not guaranteed by the Company and the Company is not subject to the terms of the indenture governing the 2024 Notes.

At any time prior to June 1, 2019, the Issuers may, from time to time, redeem up to 35% of the aggregate principal amount of the 2024 Notes with an amount of cash not greater than the net cash proceeds of certain equity offerings at a redemption price equal to 106.250% of the principal amount of the 2024 Notes redeemed, plus accrued and unpaid interest, if any, to the date of redemption, provided that at least 65% of the aggregate principal amount issued under the indenture governing the 2024 Notes remains outstanding immediately after such redemption and the redemption occurs within 120 days of the closing date of such equity offering. Prior to June 1, 2019, the Issuers may, on any one or more occasions, redeem all or a part of the 2024 Notes for cash at a redemption price equal to 100% of the principal amount of the 2024 Notes redeemed, plus a "make-whole" premium as of and accrued and unpaid interest, if any, to the date of redemption. On and after June 1, 2019, the Issuers may redeem the 2024 Notes, in whole or in part, at redemption prices (expressed as percentages of principal amount) equal to 104.688% for the 12-month period beginning on June 1, 2019, 103.125% for the 12-month period beginning June 1, 2020, 101.563% for the 12-month period beginning on June 1, 2021, and 100% beginning on June 1, 2022, plus accrued and unpaid interest to the redemption date.

The indenture governing the 2024 Notes contains covenants that, among other things and subject to certain exceptions and qualifications, limit the Issuers' ability and the ability of their restricted subsidiaries to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make certain investments; (v) create certain liens; (vi) enter into agreements that restrict dividends or other payments from their subsidiaries to them; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) engage in transactions with affiliates; and (ix) form unrestricted subsidiaries.

5.375% Senior Unsecured Notes due 2025

On December 13, 2016, the Issuers issued $650.0 million aggregate principal amount of 5.375% senior unsecured notes due 2025 (the "2025 Notes") in an offering that was exempt from registration under the Securities Act (the "2025 Notes Offering"). The 2025 Notes Offering resulted in net proceeds to the Company, after deducting initial purchaser discounts and commissions and offering expenses, of approximately $644.1 million.

Interest is payable on the 2025 Notes semi-annually in arrears on each January 15 and July 15. The 2025 Notes are fully and unconditionally guaranteed on a senior unsecured basis by the Guarantor Subsidiaries. The 2025 Notes are not guaranteed by the Company and the Company is not subject to the terms of the indenture governing the 2025 Notes.

At any time prior to January 15, 2020, the Issuers may, from time to time, redeem up to 35% of the aggregate principal amount of the 2025 Notes with an amount of cash not greater than the net cash proceeds of certain equity offerings at a redemption price equal to 105.375% of the principal amount of the 2025 Notes redeemed, plus accrued and unpaid interest, if any, to the date of redemption, provided that at least 65% of the aggregate principal amount issued under the indenture governing the 2025 Notes remains outstanding immediately after such redemption and the redemption occurs within 120 days of the closing date of such equity offering. Prior to January 15, 2020, the Issuers may, on any one or more occasions, redeem all or a part of the 2025 Notes for cash at a redemption price equal to 100% of the principal amount of the 2025 Notes redeemed, plus a "make-whole" premium as of and accrued and unpaid interest, if any, to, the date of redemption. On and after January 15, 2020, the Issuers may redeem the 2025 Notes, in whole or in part, at redemption prices (expressed as percentages of principal amount) equal to 104.031% for the 12-month period beginning on January 15, 2020, 103.750% for the 12-month period beginning January 15, 2021, 101.344% for the 12-month period beginning on January 15, 2022, and 100% beginning on January 15, 2023, plus accrued and unpaid interest to the redemption date.

The indenture governing the 2025 Notes contains covenants that, among other things and subject to certain exceptions and qualifications, limit the Issuers' ability and the ability of their restricted subsidiaries to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make certain investments; (v) create certain liens; (vi) enter into agreements that restrict dividends or other payments from their subsidiaries to them; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) engage in transactions with affiliates; and (ix) form unrestricted subsidiaries.

5.250% Senior Unsecured Notes due 2025

On February 13, 2017, the Issuers issued $450.0 million aggregate principal amount of 5.250% senior unsecured notes due 2025 (the "New 2025 Notes") in an offering that was exempt from registration under the Securities Act (the "New 2025 Notes Offering"). The New 2025 Notes Offering resulted in net proceeds to the Company, after deducting initial purchaser discounts and commissions and offering expenses, of approximately $444.1 million.

Interest is payable on the New 2025 Notes semi-annually in arrears on each February 15 and August 15. The New 2025 Notes are fully and unconditionally guaranteed on a senior unsecured basis by the Guarantor Subsidiaries. The New 2025 Notes are not guaranteed by the Company and the Company is not subject to the terms of the indenture governing the New 2025 Notes.

At any time prior to August 15, 2020, the Issuers may, from time to time, redeem up to 35% of the aggregate principal amount of the New 2025 Notes with an amount of cash not greater than the net cash proceeds of certain equity offerings at a redemption price equal to 105.250% of the principal amount of the New 2025 Notes redeemed, plus accrued and unpaid interest, if any, to the date of redemption, provided that at least 65% of the aggregate principal amount issued under the indenture governing the New 2025 Notes remains outstanding immediately after such redemption and the redemption occurs within 120 days of the closing date of such equity offering. Prior to August 15, 2020, the Issuers may, on any one or more occasions, redeem all or a part of the New 2025 Notes for cash at a redemption price equal to 100% of the principal amount of the New 2025 Notes redeemed, plus a "make-whole" premium as of and accrued and unpaid interest, if any, to, the date of redemption. On and after January 15, 2020, the Issuers may redeem the New 2025 Notes, in whole or in part, at redemption prices (expressed as percentages of principal amount) equal to 103.938% for the 12-month period beginning on August 15, 2020, 102.625% for the 12-month period beginning August 15, 2021, 101.313% for the 12-month period beginning on August 15, 2022, and 100% beginning on August 15, 2023, plus accrued and unpaid interest to the redemption date.

The indenture governing the New 2025 Notes contains covenants that, among other things and subject to certain exceptions and qualifications, limit the Issuers' ability and the ability of their restricted subsidiaries to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make certain investments; (v) create certain liens; (vi) enter into agreements that restrict dividends or other payments from their subsidiaries to them; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) engage in transactions with affiliates; and (ix) form unrestricted subsidiaries.

5.625% Senior Unsecured Notes due 2027

On October 11, 2017, the Issuers issued $700.0 million aggregate principal amount of 5.625% senior unsecured notes due 2027 (the "2027 Notes" and together with the 2024 Notes, the 2025 Notes and the New 2025 Notes, the "Notes") in an offering that was exempt from registration under the Securities Act (the "2027 Notes Offering"). The 2027 Notes Offering resulted in net proceeds to the Company, after deducting initial purchaser discounts and commissions and offering expenses, of approximately $692.1 million.

Interest is payable on the 2027 Notes semi-annually in arrears on each April 15 and October 15. The 2027 Notes are fully and unconditionally guaranteed on a senior unsecured basis by the Guarantor Subsidiaries. The 2027 Notes are not guaranteed by the Company and the Company is not subject to the terms of the indenture governing the 2027 Notes.

At any time prior to October 15, 2020, the Issuers may, from time to time, redeem up to 35% of the aggregate principal amount of the 2027 Notes with an amount of cash not greater than the net cash proceeds of certain equity offerings at a redemption price equal to 105.625% of the principal amount of the 2027 Notes redeemed, plus accrued and unpaid interest, if any, to the date of redemption, provided that at least 65% of the aggregate principal amount issued under the indenture governing the 2027 Notes remains outstanding immediately after such redemption and the redemption occurs within 120 days of the closing date of such equity offering. Prior to October 15, 2020, the Issuers may, on any one or more occasions, redeem all or a part of the 2027 Notes for cash at a redemption price equal to 100% of the principal amount of the 2027 Notes redeemed, plus a "make-whole" premium as of and accrued and unpaid interest, if any, to, the date of redemption. On and after October 15, 2022, the Issuers may redeem the 2027 Notes, in whole or in part, at redemption prices (expressed as percentages of principal amount) equal to 102.813% for the 12-month period beginning on October 15, 2022, 101.875% for the 12-month period beginning October 15, 2023, 100.938% for the 12-month period beginning on October 15, 2024, and 100% beginning on October 15, 2025, plus accrued and unpaid interest to the redemption date.

The indenture governing the 2027 Notes contains covenants that, among other things and subject to certain exceptions and qualifications, limit the Issuers' ability and the ability of their restricted subsidiaries to: (i) incur or guarantee additional indebtedness or issue certain types of preferred stock; (ii) pay dividends on capital stock or redeem, repurchase or retire capital stock or subordinated indebtedness; (iii) transfer or sell assets; (iv) make certain investments; (v) create certain liens; (vi) enter into agreements that restrict dividends or other payments from their subsidiaries to them; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) engage in transactions with affiliates; and (ix) form unrestricted subsidiaries.

If at any time when the Notes are rated investment grade by either Moody's Investors Service, Inc. or Standard & Poor's Ratings Services and no default or event of default has occurred and is continuing, many of the foregoing covenants will be suspended. If the ratings on the Notes were to subsequently decline to below investment grade, the suspended covenants would be reinstated.

At December 31, 2018, the Company was in compliance with all required covenants under the Revolving Credit Agreement and each of the indentures governing the Notes.

Principal Maturities of Debt

Principal maturities of debt outstanding at December 31, 2018 are as follows (in thousands):

2019	$	2,413
2020		1,288
2021		436
2022		51
2023		14
Thereafter		2,200,000
Total	$	2,204,202

Interest Expense

The following amounts have been incurred and charged to interest expense for the years ended December 31, 2018, 2017 and 2016 (in thousands):

	Year ended December 31,		
	2018	2017	2016
Cash payments for interest	$ 127,668	$ 63,170	$ 65,513
Change in interest accrual	(437)	30,007	(11,604)
Amortization of deferred loan origination costs	4,745	3,985	2,739
Write-off of deferred loan origination costs	—	735	451
Amortization of bond premium	(516)	(516)	(874)
Total interest expense, net	$ 131,460	$ 97,381	$ 56,225

NOTE 9. EQUITY

Preferred Stock

Pursuant to the Company's bylaws, the Company's board of directors, subject to any limitations prescribed by law, may, without further stockholder approval, establish and issue from time to time one or more classes or series of preferred stock, par value $0.01 per share, up to an aggregate of 50.0 million shares of preferred stock. The Company had no shares of preferred stock outstanding at December 31, 2018 and 2017.

Class A Common Stock

The Company has 280.2 million shares of its Class A common stock outstanding as of December 31, 2018, which includes 0.7 million shares of time-based restricted stock awards ("RSAs") and 1.3 million shares of performance-based restricted stock awards ("PSAs"). Holders of Class A common stock are entitled to one vote per share on all matters to be voted upon by the stockholders and are entitled to ratably receive dividends when and if declared by the Company's board of directors. Upon liquidation, dissolution, distribution of assets or other winding up, the holders of Class A common stock are entitled to receive ratably the assets available for distribution to the stockholders after payment of liabilities and the liquidation preference of any of the Company's outstanding shares of preferred stock.

Class B Common Stock

The Company has 36.5 million shares of its Class B common stock outstanding as of December 31, 2018. Holders of the Class B common stock are entitled to one vote per share on all matters to be voted upon by the stockholders. Holders of Class A common stock and Class B common stock vote together as a single class on all matters presented to the Company's stockholders for their vote or approval, except with respect to the amendment of certain provisions of the Company's certificate of incorporation that would alter or change the powers, preferences or special rights of the Class B common stock so as to affect them adversely, which amendments must be by a majority of the votes entitled to be cast by the holders of the shares affected by the amendment, voting as a separate class, or as otherwise required by applicable law.

Holders of Class B common stock do not have any right to receive dividends, unless the dividend consists of shares of Class B common stock or of rights, options, warrants or other securities convertible or exercisable into or exchangeable for shares of Class B common stock paid proportionally with respect to each outstanding share of Class B common stock and a dividend consisting of shares of Class A common stock or of rights, options, warrants or other securities convertible or exercisable into or exchangeable for shares of Class A common stock on the same terms is simultaneously paid to the holders of Class A common stock. Holders of Class B common stock do not have any right to receive a distribution upon a liquidation or winding up of the Company.

Earnings per Share

Basic earnings per share ("EPS") measures the performance of an entity over the reporting period. Diluted earnings per share measures the performance of an entity over the reporting period while giving effect to all potentially dilutive common shares that were outstanding during the period. The Company uses the "if-converted" method to determine the potential dilutive effect of exchanges of outstanding PE Units (and corresponding shares of Class B common stock), and the treasury stock method to determine the potential dilutive effect of vesting of its outstanding restricted stock and restricted stock units. For the year ended December 31, 2018, Class B common stock was not recognized in dilutive EPS calculations as the effect would have been antidilutive. For the year ended December 31, 2016, Class B common stock and RSAs were not recognized in dilutive EPS calculations as the effect would have been antidilutive.

The following table reflects the allocation of net income (loss) to common stockholders and EPS computations for the periods indicated based on a weighted average number of common stock outstanding for the period:

	Year ended December 31,		
	2018	2017	2016
Basic EPS (in thousands, except per share data)			
Numerator:			
Basic net income (loss) attributable to Parsley Energy, Inc. Stockholders	$ 369,127	$ 106,774	$ (74,182)
Denominator:			
Basic weighted average shares outstanding	272,226	240,733	161,793
Basic EPS attributable to Parsley Energy, Inc. Stockholders	$ 1.36	$ 0.44	$ (0.46)
Diluted EPS			
Numerator:			
Net income (loss) attributable to Parsley Energy, Inc. Stockholders	369,127	106,774	(74,182)
Effect of conversion of the shares of Company's Class B common stock to shares of the Company's Class A common stock	—	17,646	—
Diluted net income (loss) attributable to Parsley Energy, Inc. Stockholders	$ 369,127	$ 124,420	$ (74,182)
Denominator:			
Basic weighted average shares outstanding	272,226	240,733	161,793
Effect of dilutive securities:			
Class B common stock	—	54,665	—
Time-Based Restricted Stock and Time-Based Restricted Stock Units	658	1,114	—
Diluted weighted average shares outstanding (1)	272,884	296,512	161,793
Diluted EPS attributable to Parsley Energy, Inc. Stockholders	$ 1.35	$ 0.42	$ (0.46)

(1) As of December 31, 2018, 2017 and 2016, there were 1,338,439 shares of PSAs and 640,062 and 453,863, shares related to performance-based restricted stock units ("PSUs"), respectively, that could vest in the future based on predetermined

performance and market goals. These units were not included in the computation of EPS for the years ended December 31, 2018, 2017 and 2016, respectively because the performance and market conditions had not been met, assuming the end of the reporting period was the end of the contingency period.

Noncontrolling Interest

During the year ended December 31, 2016, certain PE Unit Holders exercised their Exchange Right (as defined in *Note 12—Related Party Transactions*) under the limited liability company agreement of Parsley LLC (the "Parsley LLC Agreement"), collectively electing to exchange an aggregate of 4.1 million PE Units (and a corresponding number of shares of Class B common stock) for an aggregate of 4.1 million shares of Class A common stock (collectively, the "2016 Exchanges"). In turn, the Company exercised its call right under the Parsley LLC Agreement, electing to issue Class A common stock directly to each of the exchanging PE Unit Holders in satisfaction of their election notices. As a result of the 2016 Equity Offerings and the 2016 Exchanges, the Company's ownership of Parsley LLC increased from 81.0% to 86.5% and the PE Unit Holders' ownership of Parsley LLC decreased from 19.0% to 13.5%.

As a result of the 2017 Equity Offerings, the Company's ownership of Parsley LLC increased from 86.5% to 89.8% and the PE Unit Holders' ownership of Parsley LLC decreased from 13.5% to 10.2%. Subsequently, as a result of the consummation of the Double Eagle Acquisition, the Company's ownership of Parsley LLC decreased from 89.8% to 78.4% and the PE Unit Holders' ownership of Parsley LLC increased from 10.2% to 21.6%. Any impact to additional paid in capital as a result of the 2017 Equity Offerings was completely offset by a valuation allowance.

During the year ended December 31, 2017, certain PE Unit Holders exercised their Exchange Right under the Parsley LLC Agreement, collectively electing to exchange an aggregate of 5.7 million PE Units (and a corresponding number of shares of Class B common stock) for an aggregate of 5.7 million shares of Class A common stock (collectively, the "2017 Exchanges"). In turn, the Company exercised its call right under the Parsley LLC Agreement, electing to issue Class A common stock directly to each of the exchanging PE Unit Holders in satisfaction of their election notices. As a result of the 2017 Exchanges, the Company's ownership of Parsley LLC increased from 78.4% to 80.2% and the PE Unit Holders' ownership of Parsley LLC decreased from 21.6% to 19.8%.

During the year ended December 31, 2018, certain PE Unit Holders exercised their exchange right under the Parsley LLC Agreement, collectively electing to exchange an aggregate of 25.6 million PE Units (and a corresponding number of shares of Class B common stock) for an aggregate of 25.6 million shares of Class A common stock (collectively, the "2018 Exchanges"). In turn, the Company exercised its call right under the Parsley LLC Agreement, electing to issue Class A common stock directly to each of the exchanging PE Unit Holders in satisfaction of their election notices. As a result of the 2018 Exchanges, the Company's ownership in Parsley LLC increased from 80.2% to 88.5% and the ownership of the PE Unit Holders in Parsley LLC decreased from 19.8% to 11.5%.

Because these changes in the Company's ownership interest in Parsley LLC did not result in a change of control, the transactions were accounted for as equity transactions under ASC Topic 810, *Consolidation*, which requires that any differences between the carrying value of the Company's basis in Parsley LLC and the fair value of the consideration received are recognized directly in equity and attributed to the controlling interest.

The Company has consolidated the financial position and results of operations of Parsley LLC and reflected that portion retained by the PE Unit Holders as a noncontrolling interest.

The following table summarizes the net income (loss) attributable to noncontrolling interests:

	Year ended December 31,		
	2018	2017	2016
		(in thousands)	
Net income (loss) attributable to the noncontrolling interests of:			
Parsley LLC	$ 76,079	$ 17,645	$ (14,953)
Pacesetter Drilling, LLC	763	(499)	218
Total net income (loss) attributable to noncontrolling interests	$ 76,842	$ 17,146	$ (14,735)

On April 21, 2015, Parsley Energy Operations established Pacesetter as a wholly owned subsidiary and, on June 2015, (i) Pacesetter acquired certain oilfield drilling assets and (ii) Pacesetter's former president acquired a 37.0% interest in Pacesetter (with Parsley Energy Operations retaining a 63.0% interest in Pacesetter). As a result of these transactions, the Company has consolidated the financial position and results of operations of Pacesetter. The 37.0% interest retained by Pacesetter's former president is reflected as a noncontrolling interest. As discussed in *Note 7—Sales of Oil and Natural Gas Properties*, during the year ended December 31, 2018, Pacesetter completed the sale of all of its physical assets. Following the sale, Pacesetter made an owner distribution of $2.0 million. Following the liquidation of Pacesetter, which is expected to take place in 2019, its remaining assets will be distributed to its members, including Parsley Energy Operations.

NOTE 10. STOCK-BASED COMPENSATION

In connection with the Company's initial public offering (the "IPO"), the Company adopted the Parsley Energy, Inc. 2014 long-term Incentive Plan ("LTIP") for employees, consultants and directors of the Company who perform services for the Company. The shares to be delivered under the LTIP shall be made available from (i) authorized but unissued shares, (ii) shares held as treasury stock or (iii) previously issued shares reacquired by the Company including shares purchased on the open market. A total of 12.7 million shares of Class A common stock have been authorized for issuance under the LTIP. At December 31, 2018, the Company had 8.7 million shares of Class A common stock available for future grant.

On February 12, 2018, the PSUs granted in 2016 and 2017 were converted into PSAs at 200% of the target payout for such awards. Similarly, certain of the time-based restricted stock units ("RSUs") granted in 2016 were also converted to RSAs on February 12, 2018. As converted, the PSAs and RSAs are intended to be economically identical to the pre-conversion awards with the same material terms and conditions, including vesting schedules and performance criteria.

Stock-based compensation expense recorded for each type of stock-based compensation award for the years ended December 31, 2018, 2017 and 2016 is as follows (in thousands):

	Year ended December 31,		
	2018	2017	2016
Time-based restricted stock	$ 7,200	$ 5,492	$ 3,523
Time-based restricted stock units (1)	5,690	7,778	5,677
Performance-based restricted stock awards (2)	6,987	6,349	3,671
Total stock-based compensation expense	$ 19,877	$ 19,619	$ 12,871

(1) Stock-based compensation expense relating to time-based restricted stock units with ratable vesting is recognized on a straight-line basis over the requisite service period for each separately vesting portion of the award as if the award was, in-substance, multiple awards.

(2) Includes stock-based compensation expense related to historical PSUs prior to the conversion of such awards to PSAs.

Stock-based compensation is included in *General and administrative expenses* on the Company's consolidated statement of operations.

Time-Based Restricted Stock

RSAs are awards of Class A common stock that are legally issued and outstanding. RSAs are subject to restrictions on transfer and are generally subject to a risk of forfeiture if the award recipient ceases providing services to the Company prior to the lapse of the restrictions. The stock-based compensation expense for these awards was determined using the closing price on the date of grant applied to the total number of shares that were anticipated to fully vest. The following table summarizes the

RSA activity for the year ended December 31, 2018:

	Time-Based Restricted Stock	Grant Date Fair Value
Outstanding at January 1, 2018	779,346	$ 22.30
Awards granted	302,221	$ 23.81
Forfeited	(9,620)	$ 25.62
Converted from PSUs	241,928	$ 16.70
Vested	(598,023)	$ 19.37
Outstanding at December 31, 2018	715,852	$ 23.44

Time-Based Restricted Stock Units

RSUs represent the right to receive shares of Class A common stock at the end of the vesting period in an amount equal to the number of RSUs that vest. RSUs are subject to restrictions on transfer and are generally subject to a risk of forfeiture if the award recipient ceases providing services to the Company prior to the lapse of the restriction. The stock-based compensation expense of such RSUs was determined using the closing price on the date of grant applied to the total number of shares that were anticipated to fully vest. The following table summarizes the RSU activity for the year ended December 31, 2018:

	Time-Based Restricted Stock Units	Grant Date Fair Value
Outstanding at January 1, 2018	1,199,719	$ 19.36
Awards granted	359,767	$ 24.47
Forfeited	(91,834)	$ 23.23
Converted	(241,928)	$ 16.70
Vested	(502,370)	$ 17.25
Outstanding at December 31, 2018	723,354	$ 23.78

Performance-Based Restricted Stock Units and Performance-Based Restricted Stock Awards

During 2018, 2017 and 2016, PSUs and PSAs were granted with a three year performance period. The terms and conditions of the PSAs and PSUs allow for vesting of the awards ranging between forfeiture and 200% of target. The vesting level is calculated based on the actual total stockholder return achieved during the performance period compared to the total stockholder return of a predetermined peer group. The fair value of such PSUs or PSAs was determined using a Monte Carlo simulation and will be recognized over the applicable three year performance period. The Monte Carlo simulation model utilizes multiple input variables that determine the probability of satisfying the market condition stipulated in the award to calculate the fair value of the award. Expected volatilities 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. The Company used the following assumptions to estimate the fair value of PSUs and PSAs granted during the periods indicated:

	Year Ended December 31,		
	2018	2017	2016
Risk-free interest rate	2.25%	1.45%	0.88%
Range of volatilities	34.4% - 82.2%	37.7% - 79.5%	35.0% - 65.1%

During 2018, outstanding PSUs were converted into PSAs with the same terms and conditions, including vesting provisions, as the historical PSUs. As converted, the PSAs are intended to be economically identical to the pre-conversion PSUs originally granted. Due to the nature of restricted stock awards, the number of as-converted PSAs is equal to the maximum number of PSAs (i.e., 200% of the target number of PSUs) that may vest. However, the PSAs will only vest based on actual performance achievement during the applicable performance period to the same extent as the pre-conversion PSUs would have vested, and any such PSAs that do not vested will be forfeited. No accounting charge was taken in connection with this conversion.

The following table summarizes the PSU activity for the year ended December 31, 2018:

	Performance-Based Restricted Units	Grant Date Fair Value
Outstanding at January 1, 2018	640,062	$ 30.11
Converted to PSAs	(428,127)	$ 30.11
Vested	(211,935)	$ 30.11
Outstanding at December 31, 2018	—	$ —

The following table summarizes the PSA activity for the year ended December 31, 2018:

	Performance-Based Restricted Units	Grant Date Fair Value
Outstanding at January 1, 2018	—	$ —
Awards granted	500,268	$ 13.72
Converted from PSUs	856,254	$ 16.52
Forfeited	(18,083)	$ 22.38
Outstanding at December 31, 2018	1,338,439	$ 15.07

The following table reflects the future stock-based compensation expense to be recorded for the stock-based compensation awards that were outstanding at December 31, 2018 (in thousands):

	Time-Based Restricted Stock	Time-Based Restricted Stock Units	Performance-Based Restricted Stock Awards	Total
2019	$ 4,554	$ 4,993	$ 4,959	$ 14,506
2020	2,122	2,342	2,313	6,777
2021	211	240	—	451
Total	$ 6,887	$ 7,575	$ 7,272	$ 21,734

NOTE 11. INCOME TAXES

The Company is a corporation and is subject to U.S. federal income tax and the Texas Margins Tax. On December 22, 2017, the Tax Act was enacted by the U.S. government. The Tax Act made broad and complex changes to the U.S. corporate income tax code. Among other changes, the Tax Act: (i) reduced the U.S. federal corporate income tax rate from 35% to 21%; (ii) repealed the corporate alternative minimum tax and provides for a refund of previously accrued alternative minimum tax credits; (iii) modified the provisions relating to the limitations on deductions for executive compensation of publicly traded corporations; (iv) enacted new limitations regarding the deductibility of interest expense and (v) imposed new limitations on the utilization of net operating losses arising in taxable years beginning after December 31, 2017.

GAAP requires that the impact of tax legislation be recognized in the period in which the law was enacted. As a result of the Tax Act, the Company remeasured its deferred tax assets and liabilities based on the federal income and state income tax rates at which they are now expected to reverse, and they now generally reflect a federal income tax rate of 21%. The enacted rate change resulted in a noncash increase of approximately $23.9 million to the Company’s income tax provision, a corresponding reduction of $23.9 million to the Company’s net noncurrent deferred tax asset balance and a reduction in valuation allowance of $24.3 million at December 31, 2017. There were no adjustments recorded to these estimates during the year ended December 31, 2018.

The Company's effective combined U.S. federal and state income tax rate as of December 31, 2018, 2017 and 2016 was 19.1%, 4.4% and 16.4% respectively.

During the years ended December 31, 2018, 2017 and 2016, the Company recognized income tax expenses of $105.5 million and $5.7 million and an income tax benefit of $23.8 million, respectively. Total income tax differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due primarily to the change in the valuation allowance, the change in the TRA liability, state taxes and the impact of income (loss) attributable to noncontrolling ownership interests.

At December 31, 2018, the Company did not have any accrued liability for uncertain tax positions and does not anticipate recognition of any significant liabilities for uncertain tax positions during the next 12 months. The Company's policy is to record interest and penalties relating to uncertain tax positions in income tax expense.

The components of the income tax expense (benefit) were as follows for the periods indicated (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Federal:			
Current	$ —	$ (44)	$ 158
Deferred	101,023	(423)	(18,461)
Total federal	101,023	(467)	(18,303)
State, net of federal benefit:			
Deferred	4,452	6,175	879
Total state	4,452	6,175	879
Income tax expense (benefit)	$ 105,475	$ 5,708	$ (17,424)

The following table reconciles the income tax expense (benefit) with income tax expense at the federal statutory rate for the periods indicated (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Income (loss) before income taxes	$ 551,444	$ 129,628	$ (106,341)
Less: net (income) loss before income taxes attributable to noncontrolling interest	(77,446)	(18,725)	14,579
Income (loss) attributable to Parsley Energy, Inc. Stockholders before income taxes	473,998	110,903	(91,762)
Income taxes at the federal statutory rate	99,539	38,816	(32,120)
State income taxes, net of federal benefit	4,452	6,175	879
Provision to return adjustment	(1,018)	178	(237)
Permanent and other	(2,285)	166	(61)
TRA liability change	92	(12,547)	(2,573)
Valuation allowance	4,695	(26,657)	32,215
Valuation allowance charged to equity	—	—	(15,527)
Valuation allowance due to the reduction in federal statutory rate	—	(24,356)	—
Income tax provision due to change in federal statutory rate	—	23,933	—
Income tax expense (benefit)	$ 105,475	$ 5,708	$ (17,424)
Net income (loss) attributable to Parsley Energy, Inc. Stockholders	$ 369,127	$ 106,774	$ (74,182)
Net income (loss) attributable to noncontrolling interest	$ 76,842	$ 17,146	$ (14,735)

As of December 31, 2018, the Company had approximately $0.4 million of alternative minimum tax credits available that are expected to be refunded between 2019 and 2021. In addition, the Company had approximately $1,419.1 million of federal net operating loss carryovers that expire during the years 2034 through 2037. The tax benefits of carryforwards are recorded as an asset to the extent that management assesses the utilization of such carryforwards to be more likely than not. When the future utilization of some portion of the carryforwards is determined to not be more likely than not, a valuation allowance is provided to reduce the recorded tax benefits from such assets. As of December 31, 2018, the Company had a valuation allowance of $13.9 million as a result of management's assessment of the realizability of deferred tax assets.

Internal Revenue Code ("IRC") Section 382 addresses company ownership changes and specifically limits the utilization of certain deductions and other tax attributes on an annual basis following an ownership change. The Company does not believe it experienced an ownership change within the meaning of IRC Section 382 during 2018. Even if the Company did experience an ownership change in 2018, any resulting limitation on the use of the Company's net operating loss carryforwards under IRC Section 382 would not result in a current federal tax liability at December 31, 2018, and the Company does not believe that the resulting Section 382 annual limitation would prevent its utilization of NOLs prior to their expiration.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities were as follows (in thousands):

	December 31,	
	2018	2017
Assets:		
Asset retirement obligations	$ 4,723	$ 4,854
Deferred stock-based compensation	6,718	7,874
Derivative fair value loss	—	12,493
Accrued compensation	4,650	4,241
Net operating loss carryforward	299,250	48,666
Other	—	78
Total deferred tax assets	315,341	78,206
Less: Valuation allowance	(13,862)	(9,264)
Net deferred tax assets	301,479	68,942
Liabilities:		
Book basis of oil and natural gas properties in excess of tax basis	(423,102)	(89,299)
Derivative fair value gain	(9,450)	—
Earnings in investment in subsidiary	(156)	(828)
Other	(294)	(218)
Total deferred tax liabilities	(433,002)	(90,345)
Net deferred tax liability	$ (131,523)	$ (21,403)

With respect to income taxes, the Company's policy is to account for interest charges as *Interest expense, net* and any penalties as *Other income (expense)* in the Company's consolidated statements of operations. The Company files income tax returns at the federal level and at the state level (Texas), and a number of such returns remain open for examination. The Company's earliest open years in its key jurisdictions are as follows:

U.S. federal	2015
State of Texas	2014

The Company has evaluated all tax positions for which the statute of limitations remains open and believes that the material positions taken would more likely than not be sustained by examination. Therefore, at December 31, 2018, the Company had not established any reserves for, nor recorded any unrecognized benefits related to, uncertain tax positions.

Tax Receivable Agreement

In connection with the IPO, on May 29, 2014, the Company entered into a Tax Receivable Agreement (the "TRA") with Parsley LLC and certain PE Unit Holders prior to the IPO (each such person a "TRA Holder"), including certain executive officers. The TRA generally provides for the payment by the Company of 85% of the net cash savings, if any, in U.S. federal, state, and local income tax or franchise tax that the Company actually realizes (or is deemed to realize in certain circumstances) in periods after the IPO as a result of (i) any tax basis increases resulting from the contribution in connection with the IPO by such TRA Holder of all or a portion of its PE Units to the Company in exchange for shares of Class A common stock, (ii) the tax basis increases resulting from the exchange by such TRA Holder of PE Units for shares of Class A common stock or, if either the Company or Parsley LLC so elects, cash, and (iii) imputed interest deemed to be paid by the Company as a result of, and additional tax basis arising from, any payments the Company makes under the TRA. The term of the TRA commenced on May 29, 2014, and continues until all such tax benefits have been utilized or expired, unless the Company exercises its right to terminate the TRA. If the Company elects to terminate the TRA early, it would be required to make an immediate payment equal to the present value of the hypothetical future tax benefits that could be paid under the TRA (based upon certain assumptions and deemed events set forth in the TRA). In addition, payments due under the TRA will be similarly accelerated following certain mergers or other changes of control.

The actual amount and timing of payments to be made under the TRA will depend on a number of factors, including the amount and timing of taxable income generated in the future, changes in future tax rates, the use of loss carryovers and the portion of the Company's payments under the TRA constituting imputed interest. As of December 31, 2018, there have been no payments associated with the TRA.

As a result of the Tax Act's reduction in the corporate tax rate from 35% to 21% and the reduction in the valuation allowance the Company recorded in 2016, during the year ended December 31, 2017, the Company recorded a net decrease to the TRA liability of $35.8 million, which is comprised of a decrease of $55.9 million associated with the corporate rate reduction and an increase of $20.1 million related to the change in valuation allowance.

As of December 31, 2018 and December 31, 2017, the Company had recorded a TRA liability of $68.1 million and $58.5 million, respectively, for the estimated payments that will be made to the PE Unit Holders who have exchanged shares, along with corresponding deferred tax assets, of $80.1 million and $68.8 million, respectively, as a result of the increase in tax basis arising from such exchanges and the decrease in tax basis as a result of the decrease in the future statutory tax rate.

NOTE 12. RELATED PARTY TRANSACTIONS

Well Operations

During the years ended December 31, 2018, 2017 and 2016, several of the Company's directors, officers, their immediate family and entities affiliated or controlled by such parties ("Related Party Working Interest Owners") owned non-operated working interests in certain of the oil and natural gas properties that the Company operates. The revenues disbursed to such Related Party Working Interest Owners for the years ended December 31, 2018, 2017 and 2016 totaled $1.7 million, $1.5 million and $2.5 million, respectively.

As a result of this ownership, from time to time, the Company will be in a net receivable or net payable position with these individuals and entities. The Company does not consider any net receivables from these parties to be uncollectible.

Spraberry Production Services, LLC

At December 31, 2018, the Company owned a 42.5% interest in SPS and accounts for this investment using the equity method. Using the equity method of accounting results in transactions between the Company and SPS and its subsidiaries being accounted for as related party transactions. During the years ended December 31, 2018, 2017 and 2016, the Company incurred charges totaling $9.8 million, $10.2 million and $4.4 million, respectively, for services performed by SPS for the Company's well operations and drilling activities.

Lone Star Well Service, LLC

The Company makes purchases of equipment used in its drilling operations from Lone Star Well Service, LLC ("Lone Star"). Lone Star is controlled by SPS. During the years ended December 31, 2018, 2017 and 2016, the Company incurred charges totaling $3.8 million, $6.5 million and $6.3 million, respectively, for services performed by Lone Star for the Company's well operations and drilling activities.

Riverbend Acquisition

During the year ended December 31, 2016, the Company acquired 8,800 gross (6,269 net) acres located in Glasscock, Midland and Reagan Counties, Texas, along with net production of approximately 900 Boe/d from existing wells, from Riverbend Permian L.L.C. ("Riverbend"), for total consideration of $177.1 million, after customary purchase price adjustments (the "Riverbend Acquisition"). Randolph J. Newcomer, Jr., a former member of the Company's board of directors, is the President and Chief Executive Officer of Riverbend. As the transaction involved a related party at the time it was entered into, the Riverbend Acquisition was approved by the disinterested members of the Company's board of directors. The Company reflected $37.9 million of the total consideration paid as part of its cost subject to depletion within its oil and natural gas properties and $139.2 million as unproved leasehold costs within its oil and natural gas properties for the year ended December 31, 2016.

Exchange Right

In accordance with the terms of the Parsley LLC Agreement, the PE Unit Holders generally have the right to exchange (the "Exchange Right") their PE Units (and a corresponding number of shares of the Class B common stock) for shares of Class A common stock at an exchange ratio of one share of Class A common stock for each PE Unit (and a corresponding share of Class B common stock) exchanged (subject to conversion rate adjustments for stock splits, stock dividends and reclassifications) or, if the Company or Parsley LLC so elects, cash. As a PE Unit Holder exchanges its PE Units, the Company's interest in Parsley LLC will be correspondingly increased. Refer to *Note 9—Equity—Noncontrolling Interest*.

During the year ended December 31, 2018, an officer of the Company elected to exchange 250,000 PE Units (and a corresponding number of shares of Class B common stock) for 250,000 shares of Class A common stock. The Company exercised its call right under the Parsley LLC Agreement and elected to issue Class A common stock to the exchanging PE Unit Holder in satisfaction of such individual's election notice.

NOTE 13. COMMITMENTS AND CONTINGENCIES

Legal Matters

The Company is party to 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 any such proceedings or claims will not have a material adverse effect, individually or in the aggregate, on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future results of operations. The Company will continue to evaluate proceedings and claims involving the Company on a regular basis and will establish and adjust any reserves as appropriate to reflect its assessment of the then-current status of the matters.

Environmental Obligations

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed as incurred. The Company has established procedures for the ongoing evaluation of its operations, to identify potential environmental exposures and to comply with regulatory policies and procedures.

The Company accounts for environmental contingencies in accordance with the accounting guidance related to accounting for contingencies. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. At December 31, 2018 and 2017, the Company had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Drilling Commitments

The Company periodically enters into contractual arrangements under which the Company is committed to expend funds to drill wells in the future, including agreements to secure drilling rig services, which require the Company to make future minimum payments to the rig operators. The Company records drilling commitments in the periods in which well capital is incurred or rig services are provided. The following table summarizes the Company's drilling commitments as of December 31, 2018 (in thousands):

	Payments Due by Period						
	2019	2020	2021	2022	2023	Thereafter	Total
Drilling commitments	$ 52,740	$ 27,754	$ 9,908	$ —	$ —	$ —	$ 90,402

Derivative Obligations

The Company's future deferred premium payments related to derivative agreements as of December 31, 2018 was as follows (in thousands):

	Payments Due by Period						
	2019	2020	2021	2022	2023	Thereafter	Total
Derivative obligations	$ 51,099	$ 3,285	$ —	$ —	$ —	$ —	$ 54,384

Operating Leases

The Company's estimated future minimum lease payments under long-term operating lease agreements as of December 31, 2018 was as follows (in thousands):

	Payments Due by Period						
	2019	2020	2021	2022	2023	Thereafter	Total
Office Leases	$ 9,816	$ 9,699	$ 16,639	$ 22,473	$ 21,822	$ 148,508	$ 228,957
Field Equipment	9,182	1,690	18	—	—	—	10,890
Office Equipment	260	260	93	—	—	—	613
Total	$ 19,258	$ 11,649	$ 16,750	$ 22,473	$ 21,822	$ 148,508	$ 240,460

Rent expense for the years ended December 31, 2018, 2017 and 2016 was $13.1 million, $9.5 million and $7.1 million, respectively.

Firm Transportation and Crude Oil Sales Agreements

The Company sells oil and natural gas under a variety of contractual agreements, some of which specify the delivery of fixed and determinable quantities.

The following table presents gross volume information related to certain of the Company's long-term firm transportation and crude oil sales agreements as of December 31, 2018:

	For the years ended December 31,						
	2019	2020	2021	2022	2023	Thereafter	Total
Oil (MMBbl)(1)	18.5	16.4	16.4	16.4	16.4	24.7	108.8
Dollar commitment(2) (in thousands)	$ 28,937	$ 27,274	$ 27,931	$ 28,662	$ 29,401	$ 45,414	$ 187,619

(1) This table is based on third-party pipeline operations that have commenced as of December 31, 2018. See "Item 1. Business—Transportation and Delivery Commitments" for additional information.

(2) These amounts equal the total deficiency fees payable if the Company is unable to meet all of its contractual delivery commitments under its long-term firm transportation and crude oil sales agreements.

The Company expects to fulfill these delivery commitments with production from its existing proved developed and proved undeveloped reserves, which the Company regularly monitors to ensure sufficient availability. In addition, the Company monitors its current production, its anticipated future production and its future development plans, in each case factoring in production attributable to third-party working, royalty and overriding royalty interest owners, in order to meet its delivery commitments. If production volumes are not sufficient to meet these contractual delivery commitments, the Company may be subject to deficiency fees unless it purchases commodities in the market to satisfy such commitments.

NOTE 14. DISCLOSURES ABOUT FAIR VALUE OF FINANCIAL INSTRUMENTS

The Company uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. 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. These two types of inputs are further prioritized into the following fair value input hierarchy:

Level 1: Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.

Level 2: Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1 that are either directly or indirectly observable as of the reporting date.

Level 3: Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

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, but are subject to fair value adjustments whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. These assets and liabilities can include inventory, assets and liabilities acquired in a business combination or exchanged in non-monetary transactions, proved and unproved oil and natural gas properties, asset retirement obligations and other long-lived assets that are written down to fair value when they are impaired.

The Company periodically reviews its long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable (*e.g.*, if there was a sustained decline in commodity prices or the productivity of the Company's wells). The Company reviews its oil and natural gas properties by field. An impairment loss is recognized if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of a particular asset, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of such asset.

Unproved oil and natural gas properties are assessed quarterly for impairment by considering future drilling plans, the results of exploration activities, commodity price outlooks, planned future sales remaining lease terms and the expiration of all or a portion of such projects. The Company's periodic assessment also considers its ability to prioritize expenditures to drill leases and to make payments to extend the lease term as well as its ability to enter into exchange transactions that allow for higher concentrations of ownership and development. The Company recognizes leasehold abandonment expense for unproved properties at the time when the lease term has expired or sooner based on management's periodic assessments. During the years ended December 31, 2018 and 2017, the Company recognized leasehold abandonment and impairment expense of $160.8 million, $32.9 million, and $6.1 million.

Materials and Supplies. During the years ended December 31, 2018 and 2017, the Company recognized impairments of $0.5 million and $1.1 million, respectively, primarily to reduce the carrying value of oil and gas drilling and repair items. There were no such costs recorded during 2016. The Company estimates fair value of the inventory using significant Level 2 assumptions based on third-party price quotes for the asset in an active market. The impairment charges are included in *Other income (expense)* in the Company's consolidated statements of operations.

Proved Oil and Natural Gas Properties. During the years ended December 31, 2018 and 2017, the Company did not recognize impairment charges, as the carrying amount of the assets exceeds the undiscounted future cash flows of the assets.

The Company calculates the estimated fair values using a discounted future cash flow model. Management's assumptions associated with the calculation of discounted future cash flows include commodity prices based on NYMEX futures price strips (Level 1), as well as Level 3 assumptions including (i) pricing adjustments for differentials, (ii) production costs, (iii) capital expenditures, (iv) production volumes and (v) estimated reserves.

It is reasonably possible that the estimate of undiscounted future net cash flows may change in the future resulting in the need to impair carrying values. The primary factors that may affect estimates of future cash flows are (i) commodity futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve adjustments, both positive and negative, to proved reserves, and (iv) results of future drilling activities.

Financial Assets and Liabilities Measured at Fair Value

Commodity derivative contracts are marked-to-market each quarter and are thus stated at fair value in the Company's consolidated balance sheets and in *Note 4—Derivative Financial Instruments*. The company adjusts the valuations from the valuation model for nonperformance risk and for counterparty risk. The fair values of the Company's commodity derivative instruments are classified as Level 2 measurements as they are calculated using industry standard models that utilize assumptions and inputs which are substantially observable in active markets throughout the full term of the instruments. These include market price curves, contract terms and prices, credit risk adjustments, implied market volatility and discount factors. The following summarizes the fair value of the Company's derivative assets and liabilities according to their fair value hierarchy as of the reporting dates indicated (in thousands):

	December 31, 2018			
	Level 1	Level 2	Level 3	Total
Assets:				
Commodity derivative instruments[1]	$ —	$ 211,421	$ —	$ 211,421
Total assets	$ —	$ 211,421	$ —	$ 211,421
Liabilities:				
Commodity derivative instruments[1]	$ —	$ (168,963)	$ —	$ (168,963)
Total liabilities	$ —	$ (168,963)	$ —	$ (168,963)
Net asset	$ —	$ 42,458	$ —	$ 42,458

	December 31, 2017			
	Level 1	Level 2	Level 3	Total
Assets:				
Money market funds	$ 476,619	$ —	$ —	$ 476,619
Commodity derivative instruments(1)	—	57,689	—	57,689
Total assets	476,619	57,689	—	534,308
Liabilities:				
Commodity derivative instruments(1)	—	(105,543)	—	(105,543)
Total liabilities	—	(105,543)	—	(105,543)
Net asset (liability)	$ 476,619	$ (47,854)	$ —	$ 428,765

(1) Includes deferred premiums to be settled upon expiration of the contract.

Money market funds in the preceding table consist of money market funds included in cash and cash equivalents on the Company's consolidated balance sheets at December 31, 2017. There was no such balance as of December 31, 2018. The Company's money market funds represent cash equivalents backed by the assets of high-quality major banks and financial institutions. The Company identifies the money market funds as Level 1 instruments because the money market funds have daily liquidity, quoted prices for the underlying investments can be obtained and there are active markets for the underlying investments. During the years ended December 31, 2018 and 2017, income related to these investments was $4.1 million and $7.6 million, respectively, and is recorded on the Company's consolidated statements of operations as *Interest income*.

There were no transfers into or out of Level 2 during the years ended December 31, 2018 or 2017.

Financial Instruments Not Carried at Fair Value

The following table provides the fair value of financial instruments that are not recorded at fair value in the consolidated balance sheets (in thousands):

	December 31, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents:				
Commercial paper	$ —	$ —	$ 24,939	$ 24,918
Short-term investments:				
Commercial paper	—	—	149,283	149,151
Long-term debt:				
6.250% senior unsecured notes due 2024	400,000	394,144	400,000	423,824
5.375% senior unsecured notes due 2025	650,000	605,885	650,000	658,483
5.250% senior unsecured notes due 2025	450,000	424,980	450,000	454,010
5.625% senior unsecured notes due 2027	700,000	636,041	700,000	715,169
Revolving Credit Agreement	—	—	—	—

The fair values of the Notes were determined using the December 31, 2018 quoted market price, a Level 1 classification in the fair value hierarchy. The book value of the Revolving Credit Agreement approximates its fair value as the interest rate is variable. As of December 31, 2018, there were no indicators for change in the Company's market spread.

Periodically, the Company invests in commercial paper with investment grade rated entities. The investments are carried at amortized cost and classified as held-to-maturity because the Company has the intent and ability to hold them until they mature. The net carrying value of held-to-maturity investments is adjusted for amortization of premiums and accretion of discounts to maturity over the life of the investments. Income related to these investments is recorded on the Company's consolidated statements of operations as *Interest income*.

Effect of Financial Instruments on the Consolidated Financial Statements

The following tables provide the components of the Company's cash and cash equivalents and short-term investments as of the dates indicated (in thousands):

	December 31, 2018			
Consolidated Balance Sheet Location	Cash	Commercial Paper	Money Market Funds	Total
Cash and cash equivalents	$ 163,216	$ —	$ —	$ 163,216

	December 31, 2017			
Consolidated Balance Sheet Location	Cash	Commercial Paper	Money Market Funds	Total
Cash and cash equivalents	$ 52,631	$ 24,939	$ 476,619	$ 554,189
Short-term investments	—	149,283	—	149,283

The Company has other financial instruments consisting primarily of accounts receivable, prepaid expenses, other current assets, accounts payable, accrued liabilities and capital leases that approximate their fair value due to the short-term nature of these instruments.

NOTE 15. SUBSEQUENT EVENTS

The Company has evaluated subsequent events through the date these financial statements were issued. The Company determined there were no events that required disclosure or recognition in these financial statements.

NOTE 16. SUPPLEMENTAL DISCLOSURE OF OIL AND NATURAL GAS OPERATIONS (Unaudited)

The Company has only one reportable operating segment, which is oil and natural gas development, exploration and production in the United States.

Capitalized Costs

	December 31,	
	2018	2017
	(in thousands)	
Oil and natural gas properties:		
Proved properties	$ 6,659,444	$ 4,492,802
Unproved properties	3,288,802	4,058,512
Total oil and natural gas properties	9,948,246	8,551,314
Less accumulated depreciation, depletion and amortization	(1,295,098)	(822,459)
Net oil and natural gas properties capitalized	$ 8,653,148	$ 7,728,855

Costs Incurred for Oil and Natural Gas Producing Activities

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Acquisition costs:			
Proved properties	$ 17,310	$ 482,160	$ 273,940
Unproved properties	119,662	2,893,434	1,072,250
Development costs	1,762,218	1,207,401	495,971
Total	$ 1,899,190	$ 4,582,995	$ 1,842,161

Results of Operations from Oil and Natural Gas Producing Activities

The following schedule sets forth the revenues and expenses related to the production and sale of oil, natural gas and NGLs. It does not include any interest costs or general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of the Company's oil, natural gas and NGLs operations.

	Year Ended December 31,		
	2018	2017	2016
		(in thousands)	
Oil, natural gas and natural gas liquid sales [(1)]	$ 1,814,747	$ 961,994	$ 456,504
Lease operating expenses	(144,292)	(102,169)	(59,293)
Transportation and processing costs [(1)]	(32,573)	—	—
Production and ad valorem taxes	(108,342)	(59,641)	(27,916)
Depreciation, depletion and amortization	(569,691)	(340,778)	(227,174)
Accretion of asset retirement obligations	(1,422)	(971)	(732)
Total	$ 958,427	$ 458,435	$ 141,389

(1) Natural gas and NGLs sales and transportation and processing costs for the year ended December 31, 2018 reflect adjustments associated with Parsley's adoption of ASC 606, effective January 1, 2018.

Reserve Quantity Information

The following information represents estimates of the Company's proved reserves as of December 31, 2018, which have been prepared and presented under SEC rules. These rules require SEC reporting companies to prepare their reserve estimates using specified reserve definitions and pricing based on a 12-month unweighted average of the first-day-of-the-month pricing. The pricing that was used for estimates of the Company's reserves as of December 31, 2018 was based on an unweighted average 12-month average WTI posted price per Bbl for oil and NGLs and a Waha spot natural gas price per Mcf for natural gas, adjusted for transportation, quality and basis differentials, as set forth in the following table:

	Year Ended December 31,		
	2018	2017	2016
Oil (per Bbl)	$ 61.88	$ 49.17	$ 39.36
Natural gas (per Mcf)	$ 1.64	$ 2.53	$ 2.23
Natural gas liquids (per Bbl)	$ 28.05	$ 22.20	$ 15.04

Subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This requirement has limited and may continue to limit, the Company's potential to record additional proved undeveloped reserves as it pursues its drilling program. Moreover, the Company may be required to write down its proved undeveloped reserves if it does not drill on those reserves within the required five-year timeframe. The Company does not have any proved undeveloped reserves which have remained undeveloped for five years or more.

The Company's proved oil and natural gas reserves are located in the United States in the Permian Basin of west Texas. Proved reserves were estimated in accordance with the guidelines established by the SEC and the FASB.

Oil and natural gas 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 prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The following table and subsequent narrative disclosure provides a roll forward of the total proved reserves for the years ended December 31, 2018, 2017 and 2016, as well as proved developed and proved undeveloped reserves at the beginning and end of each respective year:

	Year Ended December 31, 2018			
	Crude Oil (MBbls)	Natural Gas (MMcf)	Liquids (MBbls)	MBoe
Proved Developed and Undeveloped Reserves:				
Beginning of the year	248,531	451,703	92,632	416,447
Extensions and discoveries	102,274	130,692	35,722	159,778
Revisions of previous estimates	(22,047)	48,992	16,164	2,283
Purchases of reserves in place	3,379	5,963	1,240	5,613
Divestures of reserves in place	(12,335)	(27,947)	(5,472)	(22,465)
Production	(25,356)	(37,365)	(8,353)	(39,937)
End of the year	294,446	572,038	131,933	521,719
Proved Developed Reserves:				
Beginning of the year	119,591	240,337	49,751	209,399
End of the year	170,526	358,733	81,000	311,315
Proved Undeveloped Reserves:				
Beginning of the year	128,940	211,366	42,881	207,048
End of the year	123,920	213,305	50,933	210,404

	Year Ended December 31, 2017			
	Crude Oil (MBbls)	Natural Gas (MMcf)	Liquids (MBbls)	MBoe
Proved Developed and Undeveloped Reserves:				
Beginning of the year	136,536	223,605	48,543	222,347
Extensions and discoveries	99,916	161,989	33,426	160,340
Revisions of previous estimates	(709)	32,342	4,522	9,205
Purchases of reserves in place	33,017	64,055	12,121	55,814
Divestures of reserves in place	(3,839)	(6,962)	(1,468)	(6,467)
Production	(16,390)	(23,326)	(4,512)	(24,792)
End of the year	248,531	451,703	92,632	416,447
Proved Developed Reserves:				
Beginning of the year	61,133	123,946	24,306	106,097
End of the year	119,591	240,337	49,751	209,399
Proved Undeveloped Reserves:				
Beginning of the year	75,403	99,659	24,237	116,250
End of the year	128,940	211,366	42,881	207,048

	Year Ended December 31, 2016			
	Crude Oil (MBbls)	Natural Gas (MMcf)	Liquids (MBbls)	MBoe
Proved Developed and Undeveloped Reserves:				
Beginning of the year	73,877	157,175	23,738	123,811
Extensions and discoveries	64,005	83,815	20,698	98,672
Revisions of previous estimates	(4,476)	(19,032)	3,898	(3,750)
Purchases of reserves in place	16,041	25,024	4,023	24,235
Divestures of reserves in place	(3,543)	(9,914)	(1,424)	(6,619)
Production	(9,368)	(13,463)	(2,390)	(14,002)
End of the year	136,536	223,605	48,543	222,347
Proved Developed Reserves:				
Beginning of the year	27,628	77,612	10,890	51,453
End of the year	61,133	123,946	24,306	106,097
Proved Undeveloped Reserves:				
Beginning of the year	46,249	79,563	12,848	72,358
End of the year	75,403	99,659	24,237	116,250

Extensions and Discoveries. For the years ended December 31, 2018, 2017 and 2016, extensions and discoveries contributed to the increase of 159,778 MBoe, 160,340 MBoe and 98,672 MBoe in the Company's proved reserves, respectively, and for each such year the increase is attributable to the Company's horizontal drilling program in the Midland Basin and the Delaware Basin.

Revisions of Previous Estimates. The Company made total positive revisions in proved reserves of 2,283 MBoe and 9,205 MBoe and negative revision in proved reserves of 3,750 MBoe for the years ended December 31, 2018, 2017 and 2016, respectively.

Positive revisions of previous estimates for 2018 were 2,283 MBoe. The main driver of these positive revisions was due to the adoption of ASC 606, which resulted in a positive revision of 11,434 MBoe. Other drivers included changes in well performance, working interest, operating expenses and pricing, which together resulted in a positive revision of 3,063 MBoe. The main driver of these downward revisions was the reclassification of certain PUD reserves to unproved reserves, which accounted for a 12,214 MBoe downward revision to previous estimates related to the removal of reserves for locations determined to be outside of the Company's five-year capital expenditure plan.

Positive revisions of previous estimates for 2017 were 9,205 MBoe. The main driver of these adjustments was better than expected performance for a total of 8,134 MBoe. Additionally, positive revisions of 2,752 MBoe and 3,044 MBoe were recorded due to the increase in oil prices and production, respectively, as compared to the year ended December 31, 2016. These were offset by negative revisions of 4,725 MBoe associated with the reclassification of PUD reserves to unproved reserves.

Negative revisions of previous estimates for 2016 were 3,750 MBoe. These revisions include the reclassification of proved undeveloped reserves to unproved reserves, which accounted for a 26,597 MBoe downward revision to previous estimates (of which 18,532 MBoe related to the removal of reserves for all of the Company's vertical proved undeveloped reserve locations). Additionally, downward revisions of 2,873 MBoe were recorded due to the decline of oil prices as compared to the year ended December 31, 2015. These negative revisions were offset by positive revisions due to better than expected performance and cost reduction initiatives for a total of 25,720 MBoe.

Purchases of Reserves in Place. For the years ended December 31, 2018, 2017 and 2016, the Company added 5,613 MBoe, 55,814 MBoe and 24,235 MBoe of reserves, respectively, primarily as a result of the acquisition of developed and undeveloped acreage in the Midland and Delaware Basins. For the year ended December 31, 2018, the Company acquired 5,550 MBoe of proved reserves in the Midland Basin and 63 MBoe of proved reserves in the Delaware Basin. For the year ended December 31, 2017, the Company acquired 53,105 MBoe of proved reserves in the Midland Basin and 2,709 MBoe of proved reserves in the Delaware Basin. For the year ended December 31, 2016, the Company acquired 19,184 MBoe of proved reserves in the Midland Basin and 5,051 MBoe of proved reserves in the Delaware Basin.

Divestitures of Reserves in Place. As a result of divestitures of developed and undeveloped acreage in the Midland and Delaware Basins, the Company's reserves decreased by 22,465 MBoe, 6,467 MBoe and 6,619 MBoe during the years ended December 31, 2018, 2017 and 2016, respectively. For the year ended December 31, 2018, the Company divested 22,372 MBoe of proved reserves in the Midland Basin and 93 MBoe of proved reserves in the Delaware Basin. For the year ended December 31, 2017, the Company divested 5,936 MBoe of proved reserves in the Midland Basin and 531 MBoe of proved reserves in the Delaware Basin. For the year ended December 31, 2016, the Company divested 6,588 MBoe of proved reserves in the Midland Basin and 31 MBoe of proved reserves in the Delaware Basin.

Revision of 2016 and 2017 Standardized Measure of Discounted Future Net Cash Flows

The Company has corrected errors in the unaudited standardized measure of discounted future net cash flows calculation previously reported in the notes to the Company's financial statements for the years ended December 31, 2017 and 2016. The Company has revised the line items entitled 10% discount to reflect timing of cash flows and net changes in income taxes as a result of the revision to the timing of discounted future net cash flows for each respective period. The tables below set forth the effect of these errors in the standardized measure of discounted future net cash flows in the notes to the Company's financial statements for the years ended December 31, 2017 and 2016.

	December 31, 2017			December 31, 2016		
	As Reported	Change	As Revised	As Reported	Change	As Revised
	(in thousands)					
Future cash inflows	$ 15,421,590	$ —	$ 15,421,590	$ 6,603,206	$ —	$ 6,603,206
Future development costs	(2,181,447)	—	(2,181,447)	(1,019,823)	—	(1,019,823)
Future production costs	(4,536,530)	—	(4,536,530)	(2,176,081)	—	(2,176,081)
Future income tax expenses	(1,102,385)	—	(1,102,385)	(370,337)	—	(370,337)
Future net cash flows	7,601,228	—	7,601,228	3,036,965	—	3,036,965
10% discount to reflect timing of cash flows	(4,585,723)	370,402	(4,215,321)	(1,852,653)	119,779	(1,732,874)
Standardized measure of discounted future net cash flows	$ 3,015,505	$ 370,402	$ 3,385,907	$ 1,184,312	$ 119,779	$ 1,304,091

	Year Ended December 31,					
	2017			2016		
	As Reported	Change	As Revised	As Reported	Change	As Revised
	(in thousands)					
Standardized measure of discounted future net cash flows at the beginning of the year	$ 1,184,312	$ 119,779	$ 1,304,091	$ 597,848	$ —	$ 597,848
Sales of oil and natural gas, net of production costs	(800,553)	—	(800,553)	(369,295)	—	(369,295)
Purchase of minerals in place	489,910	—	489,910	118,795	—	118,795
Divestiture of minerals in place	(50,257)	—	(50,257)	(14,591)	—	(14,591)
Extensions and discoveries, net of future development costs	1,864,041	—	1,864,041	770,947	—	770,947
Previously estimated development costs incurred during the period	58,377	—	58,377	61,756	—	61,756
Net changes in prices and production costs	525,693	—	525,693	(80,492)	—	(80,492)
Changes in estimated future development costs	(150,028)	—	(150,028)	118,930	—	118,930
Revisions of previous quantity estimates	142,510	—	142,510	84,309	—	84,309
Accretion of discount	148,314	—	148,314	69,731	—	69,731
Net change in income taxes	(603,696)	250,623	(353,073)	(199,368)	119,779	(79,589)
Net changes in timing of production and other	206,882	—	206,882	25,742	—	25,742
Standardized measure of discounted future net cash flows at the end of the year	$ 3,015,505	$ 370,402	$ 3,385,907	$ 1,184,312	$ 119,779	$ 1,304,091

The Company has assessed the materiality of these errors in accordance with SEC guidance, considering the effects of misstatements based on an analysis of quantitative and qualitative factors. Based on this analysis, the Company determined that these errors were immaterial to each of the years ended December 31, 2017 and 2016. The Company has reflected the correction of these errors in the period in which they originated and has revised the unaudited standardized measure of discounted future net cash flows disclosure in the notes to the financial statements for the years ended December 31, 2017 and 2016.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows does not purport to be, nor should it be interpreted to present, the fair value of the oil and natural gas reserves of a property. An estimate of fair value would take into account, among other things, the recovery of reserves not presently classified as proved, the value of unproved properties and consideration of expected future economic and operating conditions.

The estimates of future cash flows and future production and development costs as of December 31, 2018, 2017 and 2016 are based on the unweighted arithmetic average first-day-of-the-month price for the preceding 12-month period. Estimated future production of proved reserves and estimated future production and development costs of proved reserves are based on current costs and economic conditions. All wellhead prices are held flat over the forecast period for all reserve categories. The estimated future net cash flows are then discounted at a rate of 10%.

The standardized measure of discounted future net cash flows relating to proved oil, natural gas and NGLs reserves is as follows:

	December 31,		
	2018	2017, as revised(1)	2016, as revised(1)
		(in thousands)	
Future cash inflows	$ 22,861,246	$ 15,421,590	$ 6,603,206
Future development costs	(2,459,587)	(2,181,447)	(1,019,823)
Future production costs	(5,944,022)	(4,536,530)	(2,176,081)
Future income tax expenses	(2,061,409)	(1,102,385)	(370,337)
Future net cash flows	12,396,228	7,601,228	3,036,965
10% discount to reflect timing of cash flows(1)	(6,502,326)	(4,215,321)	(1,732,874)
Standardized measure of discounted future net cash flows	$ 5,893,902	$ 3,385,907	$ 1,304,091

(1) *See —Revision of 2016 and 2017 Standardized Measure of Discounted Future Net Cash Flows above.*

In the foregoing determination of future cash inflows, sales prices used for oil, natural gas and NGLs for December 31, 2018, 2017 and 2016 were estimated using the average price during the 12-month period, determined as the unweighted arithmetic average of the first-day-of-the-month price for each month. Prices were adjusted by lease for quality, transportation fees and regional price differentials. Future costs of developing and producing the proved gas and oil reserves reported at the end of each year shown were based on costs determined at each such year-end, assuming the continuation of existing economic conditions.

It is not intended that the FASB's standardized measure of discounted future net cash flows represent the fair market value of the Company's proved reserves. The Company cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision and the 10% discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations and no value may be assigned to probable or possible reserves.

Changes in the standardized measure of discounted future net cash flows relating to proved oil, natural gas and NGLs reserves are as follows:

	Year Ended December 31,		
	2018	2017, as revised(1)	2016, as revised(1)
		(in thousands)	
Standardized measure of discounted future net cash flows at the beginning of the year	$ 3,385,907	$ 1,304,091	$ 597,848
Sales of oil and natural gas, net of production costs	(1,561,190)	(800,553)	(369,295)
Purchase of minerals in place	76,478	489,910	118,795
Divestiture of minerals in place	(167,412)	(50,257)	(14,591)
Extensions and discoveries, net of future development costs	3,016,035	1,864,041	770,947
Previously estimated development costs incurred during the period	290,108	58,377	61,756
Net changes in prices and production costs	1,065,693	525,693	(80,492)
Changes in estimated future development costs	(177,118)	(150,028)	118,930
Revisions of previous quantity estimates	161,860	142,510	84,309
Accretion of discount	391,803	148,314	69,731
Net change in income taxes(1)	(348,834)	(353,073)	(79,589)
Net changes in timing of production and other	(239,428)	206,882	25,742
Standardized measure of discounted future net cash flows at the end of the year	$ 5,893,902	$ 3,385,907	$ 1,304,091

(1) *See —Revision of 2016 and 2017 Standardized Measure of Discounted Future Net Cash Flows above.*

NOTE 17. SUMMARY OF QUARTERLY RESULTS OF OPERATIONS (Unaudited)

The Company's unaudited quarterly financial data for the years ended December 31, 2018 and 2017 is summarized as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands, except per share amounts)			
2018				
Revenues	$ 392,741	$ 467,788	$ 511,022	$ 454,880
Operating income	$ 169,207	$ 215,505	$ 220,992	$ 22,171
Income tax expense	$ (23,325)	$ (33,243)	$ (32,454)	$ (16,453)
Net income	$ 105,463	$ 140,958	$ 134,149	$ 65,399
Net income attributable to noncontrolling interests	$ 22,573	$ 21,803	$ 20,840	$ 11,626
Net income attributable to Parsley Energy, Inc. stockholders	$ 82,890	$ 119,155	$ 113,309	$ 53,773
Net income per common share:				
Basic	$ 0.32	$ 0.44	$ 0.41	$ 0.19
Diluted	$ 0.32	$ 0.44	$ 0.41	$ 0.19
2017				
Revenues	$ 200,858	$ 213,677	$ 241,021	$ 311,488
Operating income	$ 72,531	$ 45,259	$ 63,072	$ 71,607
Income tax (expense) benefit	$ (18,402)	$ (12,216)	$ 5,080	$ 19,830
Net income (loss)	$ 38,290	$ 55,794	$ (15,161)	$ 44,997
Net income (loss) attributable to noncontrolling interests	$ 8,848	$ 15,048	$ (1,828)	$ (4,922)
Net income (loss) attributable to Parsley Energy, Inc. stockholders	$ 29,442	$ 40,746	$ (13,333)	$ 49,919
Net income (loss) per common share:				
Basic	$ 0.13	$ 0.17	$ (0.05)	$ 0.20
Diluted	$ 0.13	$ 0.17	$ (0.05)	$ 0.16

OPERATING CASH MARGIN RECONCILIATION

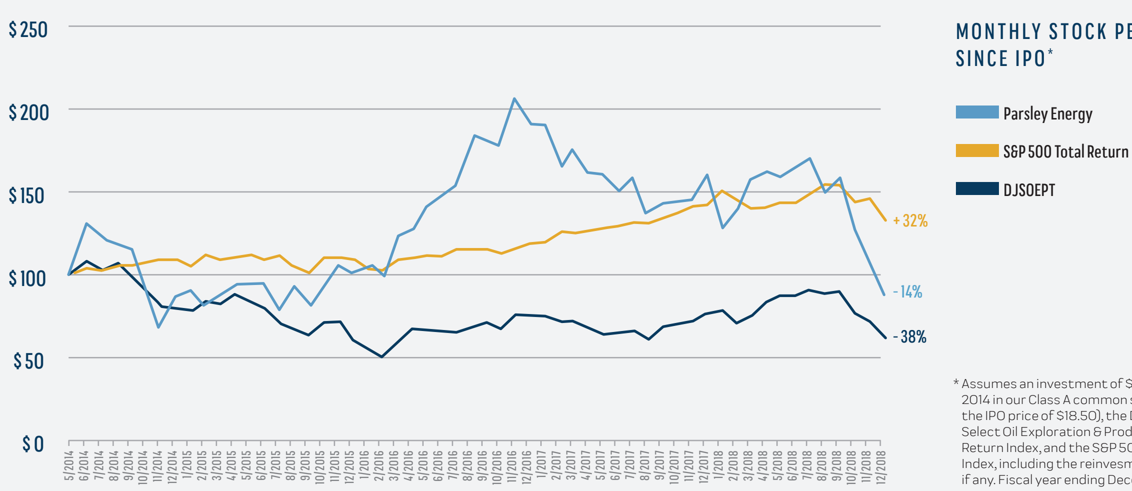
Operating cash margin is not a measure of operating income as determined by generally accepted accounting principles in the United States ("GAAP"). The amounts included in the calculations of operating cash margin were computed in accordance with GAAP. Operating cash margin is presented herein and reconciled to the GAAP measure of net income attributable to Parsley Energy, Inc. (the "Company") stockholders. The Company defines operating cash margin as net income (loss) before income tax expense (benefit), other revenues, depreciation, depletion and amortization, exploration and abandonment costs, stock-based compensation, acquisition costs, asset retirement obligation accretion expense, other operating expenses, net interest expense, (gain) loss on sale of property, prepayment premium on extinguished debt, derivative (gain) loss, change in Tax Receivable Agreement liability, interest income, and other (income) expense. The Company uses operating cash margin as an indicator of the Company's profitability and ability to manage its operating income. This measure is provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in the Company's condensed consolidated financial statements prepared in accordance with GAAP (including the notes), included in its U.S. Securities and Exchange Commission filings and posted on its website. The following table provides a reconciliation of operating cash margin to net income attributable to Parsley Energy, Inc. stockholders.

PARSLEY ENERGY, INC. AND SUBSIDIARIES OPERATING CASH MARGIN

(UNAUDITED, IN THOUSANDS, EXCEPT FOR PER UNIT DATA)[1]

	Year Ended December 31,	
	2018	2017
Net income attributable to Parsley Energy, Inc. stockholders	$ 369,127	$ 106,774
Net income (loss) attributable to noncontrolling interests	76,842	17,146
Income tax expense (benefit)	105,475	5,708
Other revenues	(11,684)	(5,050)
Depreciation, depletion and amortization	584,857	352,247
Exploration and abandonment costs	162,539	39,345
Stock-based compensation	19,877	19,619
Acquisition costs	167	10,977
Accretion of asset retirement obligations	1,422	971
Other operating expenses	19,863	10,638
Interest expense, net	131,460	97,381
(Gain) loss on sale of property	(6,454)	14,332
Prepayment premium on extinguishment of debt	–	3,891
Derivative (gain) loss	(50,342)	66,135
Change in TRA liability	437	(35,847)
Interest income	(5,464)	(7,936)
Other expense (income)	340	(783)
Operating cash margin	$ 1,398,462	$ 695,548
Operating cash margin per Boe	$ 35.02	$ 28.06
Average price per Boe, without realized derivatives	$ 45.44	$ 38.80
Operating cash margin percentage	77%	72%

[1] Certain reclassifications to prior period amounts have been made to conform with current presentation.



MONTHLY STOCK PERFORMANCE SINCE IPO*

* Assumes an investment of $100 on May 22, 2014 in our Class A common stock (using the IPO price of $18.50), the Dow Jones U.S. Select Oil Exploration & Production Total Return Index, and the S&P 500 Total Return Index, including the reinvesmtn of dividends, if any. Fiscal year ending December 31.

PARSLEY ENERGY

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