QEP RESOURCES, INC.
Form 10-K
February 20, 2019

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ___________ to ___________

001-34778
(Commission File No.)

QEP RESOURCES, INC.
(Exact name of registrant as specified in its charter)

STATE OF DELAWARE	87-0287750
(State or other jurisdiction of incorporation)	(I.R.S. Employer Identification No.)

1050 17th Street, Suite 800, Denver, Colorado 80265
(Address of principal executive offices)
Registrant's telephone number, including area code: 303-672-6900
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
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 ý 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 ý

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 ý No ¨

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 229.405 if this chapter) 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. Yes ý No ¨

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

Large accelerated filer	ý	Accelerated filer	o
Non-accelerated filer	o	Smaller reporting company	o
		Emerging growth company	o

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. o

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter (June 30, 2018): $2,905,325,233.

At January 31, 2019, there were 236,366,458 shares of the registrant's $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Part III is incorporated by reference from the registrant's Definitive Proxy Statement for its 2019 Annual Meeting of Stockholders to be filed, pursuant to Regulation 14A, no later than 120 days after the close of the registrant's fiscal year.

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Where You Can Find More Information

QEP Resources, Inc. (QEP or the Company) files annual, quarterly, and current reports with the U.S. Securities and Exchange Commission (SEC). The SEC maintains an Internet site at www.sec.gov that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC, including QEP.

Investors can also access financial and other information via QEP's website at www.qepres.com. QEP makes available, free of charge through the website, copies of Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to such reports and all reports filed by executive officers and directors under Section 16 of the Securities Exchange Act of 1934 (the Exchange Act) reporting transactions in QEP securities. Access to these reports is provided as soon as reasonably practical after such reports are electronically filed with the SEC. Information contained on or connected to QEP's website which is not directly incorporated by reference into this Annual Report on Form 10-K should not be considered part of this report or any other filing made with the SEC.

QEP's website also can be used to access copies of charters for various board committees, including the Audit Committee, and governance documents, including QEP's Corporate Governance Guidelines and QEP's Code of Conduct. While the Company recommends that you view QEP's website, the information available on QEP's website is not part of this report and is not incorporated herein by reference.

You may request a copy of filings other than an exhibit to a filing unless that exhibit is specifically incorporated by reference into that filing, at no cost by writing or calling QEP, 1050 17th Street, Suite 800, Denver, CO 80265 (telephone number: 303-672-6900).

Cautionary Statement Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains or incorporates by reference information that includes or is based upon "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 Exchange Act. Forward-looking statements give expectations or forecasts of future events. You can identify these statements by the fact that they do not relate strictly to historical or current facts. We use words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," and other words and terms of similar meaning in connection with a discussion of future operating or financial performance. Forward-looking statements include statements relating to, among other things:

- focus on returns-focused growth and superior execution and strategies to achieve these objectives;
- our strategic objectives;
- plans to review strategic alternatives and having discussions with various parties regarding a potential transaction;
- plans to reduce general and administrative expenses significantly;
- timing of the implementation of organizational changes;
- evaluation of sale of Permian midstream assets and non-core assets;
- restructuring costs associated with contractual termination benefits;
- resolution of asserted title defects with respect to the Haynesville divestiture;
- the termination of the planned Williston Basin divestiture and not realizing the expected benefits, and the impact on our strategic initiatives;
- the effect of the strategic initiatives on employees and third parties;
- the impact of the various divestitures associated with the strategic initiatives, including production and profitability projections;
- plans to grow oil, condensate and gas production;

- drilling and completion plans and strategies;
- adding additional acreage in our operating areas;
- estimated reserves and development of such reserves;
- adequacy of procedures implemented to protect against credit-related losses;
- expectations and assumptions regarding oil, gas and NGL prices;
- development of proved undeveloped (PUD) reserves within five years;
- reclassification of PUD reserves;
- PUD conversion rates and factors impacting conversion of PUD reserves;
- future development costs and funding sources for same;
- factors affecting our decision to modify our development plans;
- our ability to meet delivery and sales commitments;
- the effect of lost customers on the financial position or results of operations;

- FERC regulation of oil and gas pipelines;
- impact of tax legislation on our tax position and after-tax earnings or financial statements;
- adequacy of insurance;
- volatility of oil, gas and NGL prices and factors impacting such prices;
- the effects of oil, gas and NGL prices on our business, including the execution of our strategic initiatives;
- impact of shutting in wells;
- factors impacting our ability to transport oil and condensate and gas;
- credit agreement limitations that could prevent QEP from incurring certain indebtedness, which could limit QEP's ability to engage in acquisitions;
- credit agreement limitations on divestitures;
- impact of potential activist shareholders to our operations, personnel retention, strategies and costs;
- the conditions impacting the timing and amount of share repurchases under our share repurchase program;
- incurring penalties related to air emission noncompliance and capital expenditures to maintain or obtain operating permits and approvals;
- the underfunded status of our pension plan;
- the adjustments made to GAAP Measures to arrive at non-GAAP measures and the usefulness of non-GAAP financial measures;
- our inventory of drilling locations and the ability of that inventory to provide a solid base for growth in production and reserves;
- evaluation of potential acquisitions, divestitures and joint venture opportunities;
- our balance sheet and sufficient liquidity providing for the ability to grow oil and condensate production;
- adjustments to our capital investment program based on a variety of factors, including an evaluation of drilling and completion activities and drilling results;
- focus on operating costs and per well drilling costs;
- amount and allocation of forecasted capital expenditures (excluding property acquisitions) and, plans and sources for funding operations and capital investments;
- impact of lower or higher commodity prices and interest rates;
- focus on a sufficient liquidity position to ensure financial flexibility;
- potential for asset impairments and factors impacting impairment amounts;
- fair value estimates and related assumptions and assessment of the sensitivity of changes in assumptions, and critical accounting estimates, including estimated asset retirement obligations;
- impact of global geopolitical and macroeconomic events and the monitoring of such events;
- plans regarding derivative contracts, including the volumes utilized, and the anticipated benefits derived there from;
- outcome and impact of various claims;
- expected cost savings and other efficiencies from multi-well pad drilling, including "tank-style" development;
- delays in completion of wells, well shut-ins and volatility to operating results caused by multi-well pad drilling;
- predictability and success of our drilling operations;
- plans and ability to pursue acquisition opportunities;
- value of pension plan assets and our plans regarding additional contributions to our pension plan;
- our plans regarding contributions to the nonqualified retirement plan (SERP), medical plan and 401(k) plan;
- the estimated actuarial loss and services cost and discount rate assumptions related to our pension plan, the SERP and medical plan, as applicable;
- sufficiency of our liquidity position to ensure financial flexibility and fund our operations and capital expenditures and to achieve our strategic initiatives;
- estimates of the amount of additional indebtedness we may incur under our revolving credit facility;
- off-balance sheet arrangements;
- impact of inflation and price changes on our ability to raise capital, borrow money and retain personnel;
- leasehold development and financial capability to continue planned development;

- estimates of environmental remediation costs and factors impacting such estimates;
- changes in recorded goodwill and bargain purchase gains;
- adequacy of tax accruals and potential changes to such accruals;
- redemption of senior notes
- factors impacting our ability to borrow and the interest rates offered;
- factors impacting bad debt expense;
- unrecognized tax benefits and the realization of those benefits;
- pro forma results for acquired properties;
- estimates of future liability for deficiency charges in connection with the divestiture of our assets in Pinedale (Pinedale Divestiture);
- assumptions regarding share-based compensation;

- settlement of performance share units and restricted share units in cash;
- use of net operating losses;
- alternative minimum tax credits amount and timing; and
- expected costs associated with contractual termination benefits, including severance and accelerated vesting of share-based compensation, as part of the strategic initiatives and associated divestitures.

Any or all forward-looking statements may turn out to be incorrect. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Many such factors will be important in determining actual future results. These statements are based on current expectations and the current economic environment. They involve a number of risks and uncertainties that are difficult to predict. These statements are not guarantees of future performance. Actual results could differ materially from those expressed or implied in the forward-looking statements. Factors that could cause actual results to differ materially include, but are not limited to the following:

- the risk factors in Part I, Item 1A of this Annual Report on Form 10-K;
- any potential impact from the announcement that the Board of Directors of the Company is conducting a review of strategic alternatives;
- changes in oil, gas and NGL prices;
- global geopolitical and macroeconomic factors;
- general economic conditions, including the performance of financial markets and interest rates;
- the risks and liabilities associated with acquired assets;
- asset impairments;
- liquidity constraints, including those resulting from the cost and availability of debt and equity financing;
- drilling and completion strategies, methods and results;
- assumptions around well density/spacing and recoverable reserves per well prove to be inaccurate;
- changes in estimated reserve quantities;
- changes in management's assessments as to where QEP's capital can be most profitably deployed;
- shortages and costs of oilfield equipment, services and personnel;
- changes in development plans;
- lack of available pipeline, processing and refining capacity;
- processing volumes and pipeline throughput;
- risks associated with hydraulic fracturing;
- the outcome of contingencies such as legal proceedings;
- delays in obtaining permits and governmental approvals;
- operating risks such as unexpected drilling conditions and risks inherent in the production of oil and gas;
- weather conditions;
- changes in, adoption of and compliance with laws and regulations, including decisions and policies concerning: the environment, climate change, greenhouse gas or other emissions, renewable energy mandates, natural resources, fish and wildlife, hydraulic fracturing, water use and drilling and completion techniques, as well as the risk of legal proceedings arising from such matters, whether involving public or private claimants or regulatory investigative or enforcement measures;
- derivative activities;
- potential losses or earnings reductions from our commodity price risk management programs;
- volatility in the commodity-futures market;
- failure of internal controls and procedures;
- failure of our information technology infrastructure or applications to prevent a cyberattack;
- elimination of federal income tax deductions for oil and gas exploration and development costs;
- production, severance and property taxation rates;

- discount rates;
- regulatory approvals and compliance with contractual obligations;
- actions of, or inaction by federal, state, local or tribal governments, foreign countries and the Organization of Petroleum Exporting Countries;
- lack of, or disruptions in, adequate and reliable transportation for our production;
- competitive conditions;
- production and sales volumes;
- actions of operators on properties in which we own an interest but do not operate;
- estimates of oil and gas reserve quantities;
- reservoir performance;
- operating costs;
- inflation;

- capital costs;
- creditworthiness and performance of the Company's counterparties, including financial institutions, operating partners and other parties;
- volatility in the securities, capital and credit markets;
- actions by credit rating agencies and their impact on the Company;
- changes in guidance issued related to tax reform legislation;
- actions of activist shareholders; and
- other factors, most of which are beyond the Company's control.

QEP undertakes no obligation to publicly correct or update the forward-looking statements in this Annual Report on Form
10-K, in other documents, or on the Company's website to reflect future events or circumstances. All such statements are expressly qualified by this cautionary statement.

Glossary of Terms

Adjusted EBITDA A non-GAAP financial measure which management defines as earnings before interest, income taxes, depreciation, depletion and amortization (EBITDA), adjusted to exclude changes in fair value of derivative contracts, exploration expenses, gains and losses from asset sales, impairment, loss from early extinguishment of debt and certain other items.

Argus WTI Houston An index price reflecting the weighted average price of WTI at Magellan's East Houston crude oil terminal.

Argus WTI Midland An index price reflecting the weighted average price of WTI at the pipeline and storage hub at Midland, Texas.

B Billion.

bbl Barrel, which is equal to 42 U.S. gallons liquid volume and is a common measure of volume of crude oil and other liquid hydrocarbons.

basis The difference between a reference or benchmark commodity price and the corresponding sales price at various regional sales points.

basis swap A financial derivative that fixes the price difference between two sales points for a specified commodity volume over a specified time period.

Boe Barrels of oil equivalent.

Btu One British thermal unit – a measure of the amount of energy required to raise the temperature of a one-pound mass of water one degree Fahrenheit at sea level.

cf Cubic foot or feet is a common unit of gas measurement. One standard cubic foot equals the volume of gas in one cubic foot measured at standard conditions – a temperature of 60 degrees Fahrenheit and a pressure of 30 inches of mercury (approximately 14.7 pounds per square inch).

cfe Cubic foot or feet of natural gas equivalents.

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

dry hole An exploratory, development or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

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 gas in another reservoir.

FERC The Federal Energy Regulatory Commission.

GAAP Accounting principles generally accepted in the United States of America.

gas All references to "gas" in this report refer to natural gas.

gross "Gross" oil and gas wells or "gross" acres are the total number of wells or acres in which the Company has an ownership interest.

ICE Brent Brent crude oil traded on the Intercontinental Exchange, Inc. (ICE).

IFNPCR Inside FERC's Gas Market Report monthly settlement index for the Northwest Pipeline Corporation Rocky Mountains.

M Thousand.

MM Million.

mineral interest The economic interest or ownership of minerals, giving the owner the right to a share of the minerals produced or proceeds from the sale of the minerals.

midstream Gas gathering, compression, treating, processing, and transmission assets and activities that are non-jurisdictional. Also includes certain crude oil and produced water gathering systems and related commercial activities.

natural gas equivalents Oil and condensate and NGL volumes are converted to natural gas equivalents using the ratio of one barrel of crude oil and condensate or NGL to six Mcf of natural gas.

natural gas liquids (NGL) Liquid hydrocarbons that are extracted from the natural gas stream. NGL products include ethane, propane, butane, natural gasoline and heavier hydrocarbons.

net "Net" oil and gas wells or "net" acres are the sum of the fractional working interest the Company owns in the gross wells or acres. "Net" revenues are QEP's share of revenues from wells after deductions of royalties, overrides, net profits and other lease burdens.

NYMEX The New York Mercantile Exchange.

NYMEX HH The New York Mercantile Exchange price of natural gas at the Henry Hub.

NYMEX WTI The New York Mercantile Exchange price of West Texas Intermediate crude oil.

oil All references to "oil" in this report refer to crude oil and condensate.

oil equivalent Natural gas is converted to a crude oil equivalent at the ratio of six Mcf of natural gas to one barrel of crude oil equivalent.

possible reserves Those additional reserves that are less certain to be recovered than probable reserves.

probable reserves Those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

proved developed reserves Reserves that are expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

proved properties Properties with proved reserves.

proved reserves Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

proved undeveloped reserves or PUD reserves Proved undeveloped reserves or PUD reserves are those reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. 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. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

PUD reserves conversion rate The percentage of PUD reserves transferred to proved developed over total PUD reserves as of the prior year end.

reserves Estimated remaining quantities of crude oil, natural gas and related substances anticipated to be economically producible as of a given date by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production.

reservoir An underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

resource play Refers to regionally distributed oil and natural gas accumulation as opposed to conventional plays which are more limited in areal extent. Resource plays are characterized by continuous, aerially extensive hydrocarbon accumulations in tight sand, shale and coal reservoirs.

royalty An interest in an oil and gas lease that gives the mineral owner the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling, completing or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the minerals at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

seismic data An exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of a subsurface rock formation. 2-D seismic provides two-dimensional information and 3-D seismic provides three-dimensional views.

undeveloped reserves Reserves of any category that are expected to be recovered from new wells or from existing wells where a relatively major expenditure is required for recompletion.

working interest An interest in an oil and gas lease that gives the owner the right to drill, produce and conduct operating activities on the leased acreage and receive a share of any production, subject to all royalties, other burdens and to all capital costs and operating expenses.

FORM 10-K
ANNUAL REPORT 2018
PART I

ITEMS 1 and 2. BUSINESS AND PROPERTIES

Nature of Business

QEP Resources, Inc. (QEP or the Company) is an independent crude oil and natural gas exploration and production company with operations in two regions of the United States: the Southern Region (primarily in Texas) and the Northern Region (primarily in North Dakota). During 2018, the Company sold its Uinta Basin assets and entered into purchase and sale agreements to divest substantially all of its Haynesville/Cotton Valley assets in Louisiana and its Williston Basin assets in North Dakota. In January 2019, the Company closed the sale of its Haynesville/Cotton Valley assets. In February 2019, the Company announced the termination of the purchase and sale agreement related to its Williston Basin assets. Unless otherwise specified or the context otherwise requires, all references to "QEP" or the "Company" are to QEP Resources, Inc. and its subsidiaries on a consolidated basis. QEP was incorporated on May 18, 2010, in the State of Delaware. QEP's corporate headquarters are located in Denver, Colorado and shares of QEP's common stock trade on the New York Stock Exchange (NYSE) under the ticker symbol "QEP".

Change in Segment Reporting due to Discontinued Operations and Termination of Marketing Agreements

In December 2014, the Company sold substantially all of its midstream business, including the Company's ownership interest in QEP Midstream Partners, LP (QEP Midstream), to Tesoro Logistics LP for total cash proceeds of approximately $2.5 billion, including $230.0 million to refinance debt at QEP Midstream, and QEP recorded a pre-tax gain of approximately $1.8 billion for the year ended December 31, 2014 (Midstream Sale). As a result of the Midstream Sale, the results of operations for the QEP Field Services Company (QEP Field Services), excluding the retained ownership of the Haynesville gathering system (Haynesville Gathering), were classified as discontinued operations in the Consolidated Financial Statements.

Effective January 1, 2016, QEP terminated its contracts for resale and marketing transactions between its wholly owned subsidiaries, QEP Marketing Company (QEP Marketing) and QEP Energy Company (QEP Energy). In addition, substantially all of QEP Marketing's third-party purchase and sale agreements and gathering, processing and transportation contracts were assigned to QEP Energy, except those contracts related to natural gas storage activities and Haynesville Gathering. As a result, QEP Energy directly markets its own oil and condensate, gas and NGL production. While QEP continues to act as an agent for the sale of oil and condensate, gas and NGL production for other working interest owners, for whom QEP serves as the operator, QEP is no longer the first purchaser of this production. QEP has substantially reduced its marketing activities, and subsequently, is reporting lower resale revenue and expenses than it had prior to 2016.

In conjunction with the changes described above, QEP conducted a segment analysis in accordance with Accounting Standards Codification (ASC) Topic 280, Segment Reporting, and determined that QEP had one reportable segment effective January 1, 2016. The Company has recast its financial statements for historical periods to reflect the impact of the termination of marketing agreements to show its financial results without segments.

Financial and Operating Highlights

During the year ended December 31, 2018, QEP:

- Entered into a purchase and sale agreement to sell its assets in Haynesville/Cotton Valley in 2019 for an aggregate purchase price of approximately $735.0 million, subject to purchase price adjustments;
- Entered into a purchase and sale agreement to sell its assets in the Williston Basin in 2019 for a purchase price of $1,725.0 million, subject to purchase price adjustments;
- Received $243.6 million proceeds from disposition of assets in 2018, including the Uinta Basin and other non-core assets, which were used to pay down debt;
- Recognized a net realized oil price of $53.02 per bbl, a $4.80 per bbl increase compared to 2017;
- Delivered oil equivalent production of 51.9 MMboe;
- Delivered record oil and condensate production of 23.9 MMbbls, including a record 12.1 MMbbls in the Permian Basin;
- Reported year-end total proved reserves of 658.2 MMboe, including record proved crude oil and condensate reserves of 339.1 MMbbls, a 6% increase compared to 2017;
- Incurred capital expenditures (excluding property acquisitions) of $1,176.6 million, a 4% decrease over 2017;
- Repurchased and retired 6.2 million shares of the Company's outstanding common stock for $58.4 million;
- Generated a net loss of $1,011.6 million, or $4.25 per diluted share, primarily due to impairment expense of $1,560.9 million related to our Williston Basin and Uinta Basin assets; and
- Reported $974.8 million of Adjusted EBITDA (a non-GAAP measure defined and reconciled in Item 7 of Part II of this Annual Report on Form 10-K), a 32% increase over 2017.

Strategies

We are focused on creating value for our shareholders through returns-focused growth and superior execution. To achieve these objectives we strive to:

- operate in a safe and environmentally responsible manner;
- simplify our asset portfolio and focus on our oil basin assets;
- maintain an inventory of high return development projects in our operating areas;
- allocate capital to those projects that generate the highest returns;
- increase oil and condensate production as a percentage of total production;
- acquire businesses and assets that complement or expand our current business;
- build contiguous acreage positions that drive operating efficiencies;
- be the operator of our assets, whenever possible;
- be the low-cost driller and producer where we operate;
- actively market our production to maximize value;
- utilize derivative contracts to reduce the impact of oil, gas and NGL price volatility;
- attract and retain the best people; and
- maintain a capital structure that provides sufficient financial flexibility to successfully operate and grow the business.

Overview

QEP conducts exploration and production (E&P) activities in two of North America's most productive hydrocarbon resource plays. QEP has an inventory of developed and identified undeveloped drilling locations primarily in the Permian Basin in western Texas and the Williston Basin in North Dakota.

In February 2018, QEP's Board of Directors unanimously approved certain strategic and financial initiatives (2018 Strategic Initiatives), including plans to market its assets in the Williston Basin, Uinta Basin and Haynesville/Cotton Valley and focus its activities in the Permian Basin. The Company sold its Uinta Basin assets in September 2018 (Uinta Basin Divestiture). In November 2018, the Company's wholly owned subsidiary, QEP Energy Company, entered into a purchase and sale agreement for its assets in the Williston Basin for a purchase price of $1,725.0 million, subject to purchase price adjustments (Planned Williston Basin Divestiture). The purchase price was comprised of $1,650.0 million in cash and contractual rights to receive $75.0 million of the buyer's common stock if certain conditions were met. The transaction was subject to certain conditions, including, approval of buyer's shareholders and regulatory approvals. In February 2019, the Company agreed with the buyer to terminate the purchase and sale agreement for its assets in the Williston Basin. Following the termination of the Planned Williston Basin Divestiture, QEP will continue to operate and develop its assets in the Williston Basin, including the Company's South Antelope and Fort Berthold leaseholds. As of December 31, 2018, the Williston Basin assets were classified in the Company's Consolidated Financial Statements as held and used as the assets did not meet the held for sale criteria.

In January 2019, QEP closed its previously announced divestiture of its oil and gas assets and gathering system in the Haynesville/Cotton Valley for net cash proceeds of $605.1 million, subject to post-closing purchase price adjustments (Haynesville Divestiture). In addition, $32.2 million was placed in escrow due to title defects asserted prior to closing, all or a portion of which QEP expects to receive pursuant to the purchase and sale agreement's title dispute resolution procedures. As of December 31, 2018, the Haynesville/Cotton Valley assets were classified in the Company's Consolidated Financial Statements as held for sale.

In February 2019, QEP's Board of Directors commenced a comprehensive review of strategic alternatives to maximize shareholder value, which could result in a merger or sale of the Company or other transaction involving the Company's assets. QEP intends to engage in discussions with a variety of parties that have expressed interest in a potential transaction. Additionally, in light of the reduction of the Company's operational footprint over the last twelve months, QEP has reassessed its organizational needs and intends to significantly reduce its general and administrative expense (excluding $61.0 million of expenses associated with our 2018 Strategic Initiatives) by approximately 45% to ensure its cost structure is competitive with industry peers. The Company expects that the majority of the organizational changes will be implemented during the first half of 2019.

As part of the strategic initiatives, QEP has incurred or expects to incur costs associated with contractual termination benefits, including severance, accelerated vesting of share-based compensation and other expenses. Refer to Note 3 – Acquisitions and Divestitures, Note 8 – Restructuring Costs in Item 8 and Note 16 – Subsequent Events of Part II of this Annual Report on Form 10-K for more information.

The following map illustrates the location of the Company's significant E&P activities, the location of its Northern and Southern Regions, and related reserve and production data during the year ended December 31, 2018:

QEP sells oil and condensate and NGL volumes to refiners, marketers, midstream service providers and other companies. QEP sells gas volumes to wholesale marketers, industrial users, local distribution companies, midstream service providers and utility companies. The Company regularly evaluates counterparty credit risk and may require parental guarantees, letters of credit or prepayment from companies with perceived higher credit risk. In order to get its oil and condensate, gas and NGL volumes to their ultimate sale point, QEP has contracts with midstream providers for the gathering, transportation, processing and/or fractionation of these products. In addition, QEP has firm transportation commitments with interstate pipelines to move its gas volumes to multiple destinations dependent upon market conditions. Disruptions impacting pipelines or other midstream providers' facilities can impact QEP's production volumes. In cases where QEP's wells are not connected to sales pipelines, the Company sells its products to buyers at the well and the buyer arranges transportation to the ultimate destination.

Description of Properties

Southern Region

Permian Basin
QEP has 691.0 net productive wells in the Permian Basin. QEP has multiple targeted formations within its acreage in the Permian Basin and is actively developing oil producing zones, primarily in the Spraberry Shale and Wolfcamp formations. QEP utilizes a "tank-style" completion methodology and continues to test additional formations and evaluate the appropriate ultimate density of its development program. As of December 31, 2018, QEP had four company-operated rigs drilling in the Permian Basin. QEP has built a water infrastructure and centralized gathering infrastructure in the Permian Basin to support its tank-style development.

Haynesville/Cotton Valley
At December 31, 2018, QEP owned producing and undeveloped properties in Haynesville/Cotton Valley and additional lease rights that cover the overlying Hosston and Cotton Valley formations. QEP had 509.2 net productive wells, including its interest in non-operated wells, in Haynesville/Cotton Valley as of December 31, 2018. The Company began a refracturing program on operated wells in 2016 and continued the refracturing program throughout 2017 and 2018. In January 2019, QEP closed its previously announced divestiture of its oil and gas assets and gathering system in the Haynesville/Cotton Valley. Refer to Note 3 – Acquisitions and Divestitures and Note 16 – Subsequent Events in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Other Southern
The remainder of QEP's Southern Region primarily consists of small royalty interests over a few properties.

Northern Region

Williston Basin
QEP has 368.5 net productive wells, including its interest in non-operated wells, in the Williston Basin. QEP has developed the majority of its acreage in the Williston Basin but continues its drilling program targeting the Bakken and Three Forks formations. In addition, QEP began a refracturing program on operated wells in the Williston Basin in 2017, which continued through 2018. In November 2018, QEP entered into a purchase and sale agreement for its assets in the Williston Basin, however, the purchase and sale agreement was terminated in February 2019. Refer to Note 3 – Acquisitions and Divestitures and Note 16 – Subsequent Events in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Uinta Basin
In September 2018, QEP divested substantially all of its natural gas and oil producing properties, undeveloped acreage and related assets located in the Uinta Basin for net cash proceeds of $153.0 million, subject to post-closing purchase price adjustments. The divestiture resulted in a pre-tax loss on sale of $12.6 million, which was recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations.

Other Northern
The remainder of QEP's Northern Region leasehold interests and proved reserves are distributed over a number of fields and properties in various states. During 2017 and 2018, QEP sold the majority of its non-core properties in this area.

Reserves

At December 31, 2018 and 2017, QEP's estimated proved reserves were approximately 658.2 MMboe and 684.7 MMboe, respectively, of which 98% were Company operated in both years. Proved developed reserves represented 35% and 37% of the Company's total proved reserves at December 31, 2018 and 2017, respectively, while the remaining reserves were classified as proved undeveloped. All reported reserves are located in the United States. QEP's estimated proved reserves are summarized in the table below:

	December 31, 2018				December 31, 2017			
	Oil and condensate (MMbbl)	Gas[1] (Bcf)	NGL (MMbbl)	Total[1] (MMboe)[2]	Oil and condensate (MMbbl)	Gas[1] (Bcf)	NGL (MMbbl)	Total[1] (MMboe)[2]
Proved developed reserves	133.6	382.3	31.5	228.9	116.0	655.5	27.9	253.1
Proved undeveloped reserves	205.5	1,105.3	39.7	429.3	204.5	1,138.1	37.3	431.6
Total proved reserves	339.1	1,487.6	71.2	658.2	320.5	1,793.6	65.2	684.7

(1) Generally, gas consumed in operations was excluded from reserves, however, in some cases; produced gas consumed in operations was included in reserves when the volumes replaced fuel purchases.

(2) Natural gas is converted to a crude oil equivalent at the ratio of six Mcf of natural gas to one barrel of crude oil equivalent.

QEP's reserve, production and reserve life index for each of the years ended December 31, 2016, through December 31, 2018, are summarized in the table below:

Year Ended December 31,	Year End Reserves (MMboe)	Oil and condensate, Gas and NGL Production[2][3] (MMboe)	Reserve Life Index[1][2][3] (Years)
2016	731.4	55.8	13.1
2017	684.7	43.3	15.8
2018	658.2	49.6	13.3

(1) Reserve life index is calculated by dividing year-end proved reserves by production for that year.

(2) The reserve life index for 2018 excludes 2.2 MMboe of production volumes from the Uinta Basin due to the Uinta Basin Divestiture in September 2018. Including production volumes from the divested Uinta Basin assets, the reserve life index is 12.7 years for the year ended December 31, 2018.

(3) The reserve life index for 2017 excludes 9.9 MMboe of production volumes from Pinedale due to the Pinedale Divestiture in September 2017. Including production volumes from the divested Pinedale assets, the reserve life index is 12.9 years for the year ended December 31, 2017.

Proved Reserves

Proved reserve estimates and related information is presented consistent with the requirements of the SEC's rules for the Modernization of Oil and Gas Reporting. These rules permit the use of reliable technologies to estimate and categorize reserves and require the use of the unweighted average of the first-of-the-month commodity prices, adjusted for location and quality differentials, for the prior 12 months (unless contractual arrangements designate the price) to calculate economic producibility of reserves and the discounted cash flows reported as the Standardized Measure of Future Net Cash Flows Relating to Proved Reserves. Refer to Note 15 – Supplemental Oil and Gas Information (unaudited) in Item 8 of Part II of this Annual Report on Form 10-K for more information regarding estimates of proved reserves and the preparation of such estimates.

QEP's proved reserves in its major operating areas are summarized in the table below:

	December 31,			
	2018		2017	
Northern Region	(MMboe)	(% of total)	(MMboe)	(% of total)
Williston Basin	166.8	25 %	146.9	21 %
Uinta Basin	—	— %	100.8	15 %
Other Northern	0.3	— %	4.5	1 %
Southern Region				
Permian Basin	307.8	47 %	272.7	40 %
Haynesville/Cotton Valley	183.3	28 %	159.8	23 %
Other Southern	—	— %	—	— %
Total proved reserves	658.2	100 %	684.7	100 %

QEP's total proved reserves as of December 31, 2018, decreased 26.5 MMboe from December 31, 2017, primarily due to the Uinta Basin Divestiture, which was partially offset by an increase of proved reserves as a result of extensions and discoveries in the Permian Basin and the additional acquisitions associated with the 2017 Permian Basin Acquisition (defined in Note 3 – Acquisitions and Divestitures in Item 8 of Part II of this Annual Report on Form 10-K) during 2018. Haynesville/Cotton Valley proved reserves increased primarily due to positive performance. The Williston Basin's proved reserves increased primarily as a result of the successful refracturing program in 2018.

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Proved Undeveloped Reserves

Significant changes to PUD reserves that occurred during 2018 are summarized in the table below:

	2018
	(MMboe)
Proved undeveloped reserves at January 1,	431.6
Transferred to proved developed reserves	(51.3)
Revisions to previous estimates	50.5
Extensions and discoveries	70.3
Purchase of reserves in place	9.4
Sale of reserves in place	(81.2)
Proved undeveloped reserves at December 31,	429.3

Transfers to proved developed reserves. The costs incurred for the development of PUD reserves were approximately $606.5 million, $389.3 million and $258.1 million for the years ended December 31, 2018, 2017 and 2016, respectively.

QEP's planned and actual transfers of proved undeveloped reserves to proved developed reserves results for the year ended December 31, 2018 are summarized in the table below:

	Planned Transfers to Proved Developed Reserves in 2018 as of December 31, 2017 (PUD conversions)	Actual Transfers to Proved Developed Reserves in 2018 (PUD conversions)	Difference
	(MMboe)		
Northern Region			
Williston Basin	3.1	1.4	(1.7)
Uinta Basin[(1)]	0.8	0.8	—
Other Northern	—	—	—
Southern Region			
Permian Basin	28.2	41.3	13.1

Haynesville/Cotton Valley	9.0	8.6	(0.4)
Other Southern	—	—	—
Total	41.1	52.1	11.0
Uinta Basin[1]	(0.8)	(0.8)	—
Total excluding the Uinta Basin	40.3	51.3	11.0

(1) Uinta Basin PUD reserve conversions in 2018 include actual activity through the closing date of the Uinta Basin Divestiture.

QEP transferred 51.3 MMboe of PUD reserves to proved developed reserves in 2018 compared to 40.3 MMboe that were planned for 2018, excluding the Uinta Basin Divestiture. QEP's PUD reserves conversion rate (the percentage of booked PUD reserves) was 12%, 10% and 18% for the years ended December 31, 2018, 2017 and 2016, respectively. At December 31, 2017, QEP's planned PUD reserve conversion rate for 2018 was 10%. QEP converted more PUD reserves than expected primarily due to drilling efficiencies and drilling more PUD locations than initially planned in the Permian Basin. QEP converted 20% of Permian Basin PUD reserves in 2018. These higher than planned PUD conversions were partially offset by a lower PUD conversion rate in the Williston Basin as we shifted more development to the refracturing program in 2018.

All of QEP's proved undeveloped reserves at December 31, 2018, are scheduled to be developed within five years from the date such locations were initially disclosed as proved undeveloped reserves. QEP removes reserves associated with a PUD location from reported proved reserves if such location is scheduled, under the then-current development plan, to be drilled later than five years from the date that such location was first reported as PUD. QEP's five-year development plan generally does not contemplate a uniform (i.e. 20% per year) conversion of PUD reserves in all of its producing regions, and PUD reserve conversion rates will likely differ by producing region.

At December 31, 2018, QEP estimates that its future development costs relating to the development of PUD reserves are approximately $620.1 million in 2019, $882.0 million in 2020 and $1,025.1 million in 2021. Estimated future development costs include capital spending on major development projects, some of which will take several years to complete. QEP believes cash flow from operations and availability under its revolving credit facility will be sufficient to cover these estimated future development costs.

Revisions to previous estimates. Revisions to previous estimates reflect our ongoing evaluation of our asset portfolio. In 2018, our PUD reserves increased by 50.5 MMboe due to the factors summarized in the table below:

	2018 (MMboe)
Revisions due to:	
Changes in year-end prices (price impact to January 1, 2017 balance)	4.3
Positive performance	28.6
Change in development plans	32.2
Removal due to five year SEC rule	(22.6)
Other	8.0
Total revisions to prior estimates	50.5

In 2018, PUD reserves were revised upward by 50.5 MMboe primarily due to positive revisions from changes in development plans (32.2 MMboe) primarily as a result of consolidating working interests and extending lateral lengths in existing QEP operated PUD locations in the Permian Basin. The 28.6 MMboe positive performance revision is primarily from Haynesville/Cotton Valley's increased performance. These positive revisions were partially offset by 22.6 MMboe of PUD reserves that were no longer in our 2019 forecasted capital expenditure plan and will not be drilled and completed within five years of the initial date of booking of the reserves.

Extensions and Discoveries. Extensions and discoveries in 2018 were primarily in the Permian Basin and related to new well completions and associated new PUD locations.

Purchase of Reserves in Place. Purchase of reserves in place in 2018 was primarily related to the additional acquisitions associated with the 2017 Permian Basin Acquisition in 2018 as discussed in Note 3 – Acquisitions and Divestitures in Item 8 of Part II of this Annual Report on Form 10-K.

Sale of Reserves in Place. Sale of reserves in place in 2018 was primarily related to the Uinta Basin Divestiture as discussed in Note 3 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K.

Additional Disclosures

Refer to Note 15 – Supplemental Oil and Gas Information (unaudited) in Item 8 of Part II of this Annual Report on Form 10-K for more information pertaining to QEP's proved reserves as of the end of each of the last three years.

In addition to this filing, QEP will file reserve estimates as of December 31, 2018, with the Energy Information Administration of the Department of Energy (EIA) on Form EIA-23. Although QEP uses the same technical and economic assumptions when it prepares the Form EIA-23 as used to estimate reserves for this Annual Report on Form 10-K, it is obligated to report to the EIA reserves only for wells it operates, not for all of the wells in which it has an interest, and to include the reserves attributable to other owners in such wells.

Third Party Reserve Reports

The Company retained Ryder Scott Company, L.P. (RSC), independent oil and gas reserve evaluation engineering consultants, to prepare the estimates of all of its proved reserves as of December 31, 2018, 2017 and 2016.

Qualifications of Technical Person Preparing Reserve Reports

The individual at RSC who was responsible for overseeing the preparation of QEP's reserve estimates as of December 31, 2018, is a registered Professional Engineer in the States of Colorado and Texas and graduated with a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001. The individual has over 10 years of experience in the petroleum industry, including experience estimating and evaluating petroleum reserves. A more detailed letter, including such individual's professional qualifications, has been filed as part of Exhibit 99.1 to this report.

The individual at QEP responsible for ensuring the accuracy of the reserve estimate preparation material provided to RSC and reviewing the estimates of reserves received from RSC is QEP's Director of Corporate Reserves. This individual is a member of the Society of Petroleum Engineers and graduated with a Bachelor's of Science degree in Engineering from the University of Minnesota. This individual has over 30 years of experience in the petroleum industry, including 15 years of experience in corporate reserves management.

Technologies Used

To estimate proved reserves, the SEC allows a company to use technologies that have been proved 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 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. A variety of methodologies were used to determine QEP's proved reserve estimates. The principal methodologies employed are performance, analogy and volumetric methods.

All of the proved producing reserves as of December 31, 2018, attributable to producing wells and/or reservoirs were estimated by performance methods. Volumetric measures are then used, when available, to further corroborate these reserve estimates. Performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of historical production data available through late 2018, in those cases where such data were considered to be definitive. For wells currently producing, forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

All of QEP's proved developed non-producing and undeveloped reserves as of December 31, 2018 were estimated by analogy to offset producing wells. Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by QEP. Wells or locations that are not currently producing may start producing earlier or later than anticipated in these estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies. The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, market demand and/or allowables or other constraints set by regulatory bodies. Some combination of these methods is used to determine reserve estimates in substantially all of QEP's fields.

Internal Controls Over Proved Reserve Estimates

At the end of each year, management develops a five-year capital expenditure plan based on QEP's best available data at the time the plan is developed. The Company's capital expenditure plan includes a development plan for converting PUD reserves. The development plan includes only PUD reserves that the Company is reasonably certain 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 future location density; current commodity pricing and cost forecasts consistent with SEC guidelines; recent drilling and re-stimulated well results; availability of services, equipment, supplies and personnel; seasonal weather; and changes in drilling and completion techniques and technology. This process is intended to ensure that PUD reserves are only claimed for locations where a final investment decision has been made by the Company.

QEP maintains a Reserves Review Committee comprised of members of QEP's management team and the Company's Director of Corporate Reserves. The Reserves Review Committee meets on a semi-annual basis, including prior to the filing of reserves estimates with the SEC and any public disclosure of reserve estimates. The Reserves Review Committee reviews data that is submitted by the Director of Corporate Reserves to RSC, including cost and pricing assumptions and reserve reconciliations from the previous reserve determinations. The Director of Corporate Reserves' Annual Reserve Summary Report and the Reserve Committee's Certification are provided to the Audit Committee annually. The Audit Committee also meets annually with RSC to review the reserves estimation reporting process and disclosures. QEP's Board of Directors (Board) annually reviews the Company's five-year capital expenditure plan and approves the capital budget for the first year of the development plan.

Management reviews and revises the development plan throughout the year and may modify the development plan after evaluating a number of factors, including operating and drilling results; current and expected future commodity prices; estimated risk-based returns; estimated well density; advances in technology; cost and availability of services, equipment, supplies and personnel; acquisition and divestiture activity; and our current and projected financial condition and liquidity. Management reviews changes to the development plan with the Audit Committee and the Board quarterly. Changes in the development plan are also considered by management, the Director of Corporate Reserves and the Reserves Review Committee when reserves are estimated at year-end. If changes result in certain PUD reserves no longer being scheduled for development within five years from the date of initial booking, QEP reclassifies those PUD reserves to non-proved reserve categories. In addition, PUD locations and reserves may be removed from the development plan ahead of their five-year life expiration as a result of asset divestitures and acquisitions and associated changes in the priority of development within QEP's portfolio of assets.

Production, Prices and Production Costs

The following table sets forth the production volumes and field-level prices of oil and condensate, gas and NGL produced, and the related production costs, for the years ended December 31, 2018, 2017 and 2016:

	Year Ended December 31,		
	2018	2017	2016
Production volumes			
Oil and condensate (Mbbl)	23,932.0	19,620.7	20,293.8
Gas (Bcf)	139.6	168.9	177.0
NGL (Mbbl)	4,661.4	5,367.3	5,978.8
Total equivalent production (Mboe)	51,857.9	53,144.9	55,780.2
Average field-level price [1]			
Oil (per bbl)	$59.43	$ 47.88	$ 37.90
Gas (per Mcf)	$2.82	$ 2.92	$ 2.36
NGL (per bbl)	$23.79	$ 20.85	$ 13.97
Production costs (per Boe)			
Lease operating expense	$5.07	$ 5.55	$ 4.03
Adjusted transportation and processing costs[2]	3.33	4.61	5.18
Production and property taxes	2.52	2.15	1.70
Total production costs	$10.92	$ 12.31	$ 10.91

(1) The average field-level price does not include the impact of settled commodity price derivatives.

(2) Adjusted transportation and processing costs includes transportation and processing costs that are reflected as part of "Oil and condensate, gas and NGL sales" on the Consolidated Statements of Operations. Management adds these costs together with transportation and processing costs reflected on the Consolidated Statements of Operations to reflect the total operating costs associated with its production. Management believes that this non-GAAP measure is useful supplemental information for investors as it is reflective of the total production costs required to operate the wells for the period. This non-GAAP measure should be considered by the reader in addition to but not instead of, the financial statements prepared in accordance with GAAP. Refer to Note 2 – Revenue in Item 8 of Part II of this Annual Report on Form 10-K for more information.

A summary of oil and condensate production by major geographical area is shown in the following table:

	Year Ended December 31,			Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
Oil and condensate production volumes (Mbbl)					
Northern Region					
Williston Basin	11,229.5	12,353.5	14,658.6	(1,124.0)	(2,305.1)
Pinedale	—	403.8	670.9	(403.8)	(267.1)
Uinta Basin	447.3	656.8	774.2	(209.5)	(117.4)
Other Northern	93.2	114.2	141.9	(21.0)	(27.7)
Southern Region					
Permian Basin	12,137.4	6,060.9	3,983.9	6,076.5	2,077.0
Haynesville/Cotton Valley	15.6	26.5	28.4	(10.9)	(1.9)
Other Southern	9.0	5.0	35.9	4.0	(30.9)
Total production	23,932.0	19,620.7	20,293.8	4,311.3	(673.1)

A summary of gas production by major geographical area is shown in the following table:

	Year Ended December 31,			Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
Gas production volumes (Bcf)					
Northern Region					
Williston Basin	15.6	15.5	15.2	0.1	0.3
Pinedale	—	51.9	82.4	(51.9)	(30.5)
Uinta Basin	10.2	16.8	22.4	(6.6)	(5.6)
Other Northern	0.9	5.7	7.9	(4.8)	(2.2)
Southern Region					
Permian Basin	10.6	6.0	5.3	4.6	0.7
Haynesville/Cotton Valley	102.2	72.9	43.4	29.3	29.5
Other Southern	0.1	0.1	0.4	—	(0.3)
Total production	139.6	168.9	177.0	(29.3)	(8.1)

A summary of NGL production by major geographical area is shown in the following table:

	Year Ended December 31,			Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
NGL production volumes (Mbbl)					
Northern Region					
Williston Basin	2,495.3	3,206.1	3,182.7	(710.8)	23.4
Pinedale	—	811.0	1,417.1	(811.0)	(606.1)
Uinta Basin	99.3	152.0	203.9	(52.7)	(51.9)
Other Northern	10.5	13.4	22.3	(2.9)	(8.9)
Southern Region					
Permian Basin	2,054.4	1,168.5	1,109.9	885.9	58.6
Haynesville/Cotton Valley	0.5	16.2	28.2	(15.7)	(12.0)

Other Southern	1.4	0.1	14.7	1.3	(14.6)
Total production	4,661.4	5,367.3	5,978.8	(705.9)	(611.5)

A summary of oil equivalent total production by major geographical area is shown in the following table:

	Year Ended December 31,			Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
Total production volumes (Mboe)					
Northern Region					
Williston Basin	16,331.3	18,140.0	20,370.0	(1,808.7)	(2,230.0)
Pinedale	0.1	9,871.7	15,826.0	(9,871.6)	(5,954.3)
Uinta Basin	2,243.5	3,605.4	4,714.3	(1,361.9)	(1,108.9)
Other Northern	247.0	1,082.4	1,491.7	(835.4)	(409.3)
Southern Region					
Permian Basin	15,960.3	8,227.2	5,976.7	7,733.1	2,250.5
Haynesville/Cotton Valley	17,050.5	12,188.7	7,285.5	4,861.8	4,903.2
Other Southern	25.2	29.5	116.0	(4.3)	(86.5)
Total production	51,857.9	53,144.9	55,780.2	(1,287.0)	(2,635.3)

A regional comparison of average field-level prices and average production costs (excluding production and property taxes) per Boe is shown in the following table:

	Year Ended December 31,			Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
Average field-level oil price (per bbl)					
Northern Region	$62.63	$47.24	$36.97	$15.39	$10.27
Southern Region	$56.34	$49.30	$41.68	$7.04	$7.62
Average field-level oil price	$59.43	$47.88	$37.90	$11.55	$9.98
Average field-level gas price (per Mcf)					
Northern Region	$2.71	$2.93	$2.33	$(0.22)	$0.60
Southern Region	$2.84	$2.92	$2.42	$(0.08)	$0.50
Average field-level gas price	$2.82	$2.92	$2.36	$(0.10)	$0.56
Average field-level NGL price (per bbl)					
Northern Region	$23.56	$21.41	$14.50	$2.15	$6.91
Southern Region	$24.09	$18.87	$11.75	$5.22	$7.12
Average field-level NGL price	$23.79	$20.85	$13.97	$2.94	$6.88
Adjusted lease operating and transportation and processing costs (per Boe)					
Northern Region	$12.90	$11.24	$8.71	$1.66	$2.53
Southern Region	$5.82	$8.43	$10.79	$(2.61)	$(2.36)
Adjusted average lease operating and transportation and processing costs	$8.40	$10.16	$9.21	$(1.76)	$0.95

Northern Region

Williston Basin

Production volumes decreased 10% to 16,331.3 Mboe during 2018 compared to 2017, primarily as a result of reduced drilling and completion activity during 2018.

Production volumes decreased 11% to 18,140.0 Mboe during 2017 compared to 2016, primarily as a result of reduced drilling and completion activity during 2017, certain operational issues, under performance of certain wells, and producing well shut-ins associated with offset completion activity. The oil and condensate production decrease was partially offset by increased gas and NGL production, which was primarily attributable to higher allocated gas recovery as a result of restructuring a contract with a midstream provider starting in late 2016 and continuing in 2017.

During the years ended December 31, 2018, 2017 and 2016, Williston Basin production represented 31%, 34% and 37%, respectively, of QEP's total equivalent production.

Pinedale

Due to the divestiture of the Pinedale properties in September 2017, there was no production during the year ended December 31, 2018.

Production volumes decreased 38% to 9,871.7 Mboe during 2017 compared to 2016, primarily due to the divestiture of the Pinedale properties in September 2017 and reduced completion activity during the time that QEP owned the properties.

During the years ended December 31, 2017 and 2016, Pinedale production represented 19% and 28%, respectively, of QEP's total equivalent production.

Uinta Basin

Production volumes decreased 38% to 2,243.5 Mboe during 2018 compared to 2017, primarily due to the divestiture of the Uinta Basin properties in September 2018.

Production volumes decreased 24% to 3,605.4 Mboe during 2017 compared to 2016, primarily attributable to declining gas production from existing wells and reduced completion activity in 2017. QEP did not complete any wells in the Uinta Basin in 2017.

During the years ended December 31, 2018, 2017 and 2016, Uinta Basin production represented 4%, 7% and 8%, respectively, of QEP's total equivalent production.

Other Northern

Production volumes decreased 77% to 247.0 Mboe during 2018 compared to 2017, primarily due to the continued divestiture of properties during 2018.

Production volumes decreased 27% to 1,082.4 Mboe during 2017 compared to 2016, primarily due to the divestiture of properties during 2017.

During the years ended December 31, 2018, 2017 and 2016, Other Northern production represented less than 1%, 2% and 3%, respectively, of QEP's total equivalent production.

Southern Region

Permian Basin

Production volumes increased 94% to 15,960.3 Mboe during 2018 compared to 2017, primarily as a result of continued horizontal development activities in the Spraberry Shale and Wolfcamp formations. QEP began 2018 with six operated drilling rigs in the Permian Basin and ended 2018 with four operated drilling rigs.

Production volumes increased 38% to 8,227.2 Mboe during 2017 compared to 2016, primarily as a result of continued horizontal development activities in the Spraberry Shale and Wolfcamp formations.

During the years ended December 31, 2018, 2017 and 2016, Permian Basin production represented 31%, 15%, and 11% respectively, of QEP's total equivalent production.

Haynesville/Cotton Valley

Production volumes increased 40% to 17,050.5 Mboe during 2018 compared to 2017, due to a well refracturing program that began in 2016 and continued throughout 2017 and 2018 combined with four new well completions in 2018. The production volume increase in 2018 was partially offset by natural production decline.

Production volumes increased 67% to 12,188.7 Mboe during 2017 compared to 2016, due to a well refracturing program that began in 2016 and continued throughout 2017 combined with two new well completions in 2017. The production volume increase in 2017 was partially offset by natural production decline.

During the years ended December 31, 2018, 2017 and 2016, Haynesville/Cotton Valley's production represented 34%, 23% and 13%, respectively, of QEP's total equivalent production.

Other Southern
Production volumes decreased 15% to 25.2 Mboe during 2018 compared to 2017, due to the continued divestiture of properties.

Production volumes decreased 75% to 29.5 Mboe during 2017 compared to 2016, due to the continued divestiture of properties.

During the years ended December 31, 2018, 2017 and 2016, Other Southern production represented less than 1% of QEP's total equivalent production.

Productive Wells
The following table summarizes the Company's operated and non-operated productive wells as of December 31, 2018, all of which are located in the U.S.:

	Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Northern Region						
Williston Basin	919	368.5	—	—	919	368.5
Uinta Basin[1]	—	—	—	—	—	—
Other Northern	19	3.2	33	12.2	52	15.4
Southern Region						
Permian Basin	726	691.0	—	—	726	691.0
Haynesville/Cotton Valley	1	0.1	869	509.1	870	509.2
Other Southern	1	0.4	58	3.6	59	4.0
Total productive wells	1,666	1,063.2	960	524.9	2,626	1,588.1

(1) As a result of the Uinta Basin Divestiture, QEP no longer owns operated or non-operated productive wells in the Uinta Basin as of December 31, 2018. Refer to Note 3 – Acquisitions and Divestitures in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Although many wells produce both oil and gas, and many gas wells also have allocated NGL volumes from gas processing, a well is categorized as either an oil well or a gas well based upon the ratio of oil to gas produced at the wellhead. Additionally, each well completed in more than one producing zone is counted as a single well.

Acreage

The following table summarizes developed and undeveloped acreage in which the Company owns a working interest or a mineral interest as of December 31, 2018. "Undeveloped Acreage" includes leasehold interests that may already have been classified as containing proved undeveloped reserves and unleased mineral interest acreage owned by the Company. Excluded from the table is acreage in which the Company's interest is limited to royalty, overriding royalty or other similar interests. All leasehold acres are located in the U.S.

	Developed Acres[1]		Undeveloped Acres[2]		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Colorado	28,295	21,201	14,953	2,453	43,248	23,654
Kansas	47,233	20,879	35,543	12,865	82,776	33,744
Louisiana	70,361	63,043	1,177	1,292	71,538	64,335
Montana	38,337	14,848	324,646	55,424	362,983	70,272
New Mexico	7,300	4,131	24,651	2,476	31,951	6,607
North Dakota	141,355	68,440	164,361	53,029	305,716	121,469
South Dakota	40	40	203,330	107,551	203,370	107,591
Texas	48,913	39,167	21,472	16,563	70,385	55,730
Utah	9,194	4,418	16,666	8,381	25,860	12,799
Wyoming	50,384	20,568	32,372	9,301	82,756	29,869
Other	15,595	4,370	157,822	43,314	173,417	47,684
Total	457,007	261,105	996,993	312,649	1,454,000	573,754

(1) Developed acreage is leased acreage or mineral interests assigned to productive wells.

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

Expiring Leaseholds

The majority of our leasehold acreage is held by production. A portion of the leases covering the acreage summarized in the preceding table will expire at the end of their respective primary lease terms unless the leases are renewed, extended or drilling or production has occurred on the acreage subject to the lease prior to that date. Leases held by production generally remain in effect until production ceases. The following table sets forth the gross and net undeveloped acres subject to leases summarized in the preceding table that will expire during the periods indicated:

	Undeveloped Acres Expiring	
	Gross	Net
Year ending December 31,		
2019	2,491	587
2020	680	414
2021	480	431
2022	—	—
2023 and later	—	—
Total	3,651	1,432

Drilling Completion and Production Activities

The following table summarizes the total number of development and exploratory wells drilled (defined to include the number of wells completed at any time during the applicable year, regardless of when drilling was initiated), including both operated and non-operated wells, during the years indicated.

	Development Wells				Exploratory Wells			
	Productive		Dry		Productive		Dry	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Year Ended December 31, 2018								
Northern Region								
Williston Basin	24	10.3	—	—	—	—	—	—
Uinta Basin	2	2.0	—	—	—	—	—	—
Other Northern	—	—	—	—	—	—	—	—
Southern Region								
Permian Basin	106	105.2	—	—	—	—	—	—
Haynesville/Cotton Valley	16	4.6	—	—	—	—	—	—
Other Southern	—	—	—	—	—	—	—	—
Total	148	122.1	—	—	—	—	—	—
Year Ended December 31, 2017								
Northern Region								
Williston Basin	55	28.2	—	—	—	—	—	—
Pinedale	20	8.6	—	—	—	—	—	—
Uinta Basin	—	—	—	—	—	—	—	—
Other Northern	—	—	—	—	—	—	—	—
Southern Region								
Permian Basin	65	65.0	—	—	1	0.7	—	—
Haynesville/Cotton Valley	14	2.8	—	—	—	—	—	—
Other Southern	—	—	—	—	—	—	—	—
Total	154	104.6	—	—	1	0.7	—	—
Year Ended December 31, 2016								
Northern Region								
Williston Basin	70	39.5	—	—	—	—	—	—
Pinedale	44	24.4	—	—	—	—	—	—
Uinta Basin	11	8.0	—	—	—	—	—	—
Other Northern	3	3.0	—	—	—	—	—	—
Southern Region								
Permian Basin	19	18.8	—	—	1	0.7	—	—
Haynesville/Cotton Valley	15	2.6	—	—	—	—	—	—
Other Southern	—	—	—	—	—	—	—	—
Total	162	96.3	—	—	1	0.7	—	—

The following table presents operated and non-operated wells in the process of being drilled or waiting on completion as of December 31, 2018:

		Operated				Non-operated			
	Drilling	Drilling		Waiting on completion		Drilling		Waiting on completion	
	Rigs	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Northern Region									
Williston Basin	—	—	—	—	—	6	0.1	3	0.8
Uinta Basin	—	—	—	—	—	—	—	—	—
Other Northern	—	—	—	—	—	—	—	—	—
Southern Region									
Permian Basin[(1)]	4	13	13.0	35	35.0	—	—	—	—
Haynesville/Cotton Valley	—	—	—	—	—	1	0.0	9	0.5
Other Southern	—	—	—	—	—	—	—	—	—

(1) The number of gross operated drilling wells in the Permian Basin includes 10 wells for which surface casing has been set but as of December 31, 2018, no drilling rig was active.

Each gross well completed in more than one producing zone is counted as a single well. Delays and well shut-ins resulting from multi-well pad drilling have caused and may continue to cause volatility in QEP's quarterly operating results. In addition, delays in completion of wells could impact planned conversion of PUD reserves to proved developed reserves. QEP had 35 gross operated wells waiting on completion as of December 31, 2018.

The following table presents the number of operated and non-operated wells completed and turned to sales (put on production) for the year ended December 31, 2018:

	Operated Put on Production		Non-operated Put on Production	
	Year Ended December 31, 2018			
	Gross	Net	Gross	Net
Northern Region				
Williston Basin	11	10.1	13	0.2
Uinta Basin	2	2.0	—	—
Other Northern	—	—	—	—
Southern Region				
Permian Basin	106	105.2	—	—
Haynesville/Cotton Valley	4	4.0	12	0.6
Other Southern	—	—	—	—

The following table presents the number of operated wells in the process of being drilled or waiting on completion at December 31, 2018 and operated wells completed and turned to sales (put on production) for the year ended December 31, 2018:

	Permian Basin		Williston Basin		Haynesville/Cotton Valley		Uinta Basin	
	December 31, 2018							
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Well Progress								
Drilling	13	13.0	—	—	—	—	—	—
At total depth - under drilling rig	8	8.0	—	—	—	—	—	—
Waiting to be completed	17	17.0	—	—	—	—	—	—
Undergoing completion	5	5.0	—	—	—	—	—	—
Completed, awaiting production	5	5.0	—	—	—	—	—	—
Waiting on completion	35	35.0	—	—	—	—	—	—
Put on production	106	105.2	11	10.1	4	4.0	2	2.0

Delivery Commitments

QEP is a party to various long-term agreements that require us to physically deliver oil and condensate and gas with future firm delivery commitments as follows:

Period	Delivery Commitments (MMboe)
2019	16.2
Thereafter	64.9

These commitments are physical delivery obligations with prices based on prevailing index prices for oil and condensate and gas at the time of delivery or contracted gathering arrangements that require delivery of a fixed and determinable quantity of oil and condensate or gas in the future. None of these commitments require the Company to deliver oil and condensate or gas produced specifically from any of the Company's properties. The Company believes that its production and reserves should be adequate to meet our term sales commitments. If the Company's oil and condensate or gas production is not sufficient to satisfy its firm delivery commitments, the Company believes it can purchase sufficient volumes of oil and condensate or gas in the market at index-related prices to satisfy its commitments. The Company paid contractual cash obligations of $13.4 million, $40.4 million and $43.9 million for the years ended December 31, 2018, 2017 and 2016, respectively, for deficiencies associated with gathering and firm physical delivery obligations. See also Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations – Contractual Cash Obligations and Other Commitments, in this Annual Report on Form 10-K for discussion of firm transportation commitments related to oil and condensate and gas deliveries.

In addition, at December 31, 2018, the Company did not have a significant amount of production from QEP's owned properties that was subject to priorities or curtailments that may affect quantities delivered to its customers, priority allocations or price limitations imposed by federal or state regulatory agencies, or any other factors beyond the Company's control that may affect its ability to meet its contractual obligations other than those discussed in Part I, Item 1A – Risk Factors, in this Annual Report on Form 10-K.

Seasonality

QEP drills and completes wells throughout the year, but adverse weather conditions can impact drilling, completion and field operations, which can impact overall production volumes. Seasonal anomalies can minimize or exaggerate the impact on these operations, while extreme weather events can materially constrain our operations for short periods of time.

Significant Customers

QEP's five largest customers accounted for 49%, 59% and 48%, in the aggregate, of QEP's revenues for the years ended December 31, 2018, 2017 and 2016, respectively. The following table presents the percentages by customer that accounted for 10% or more of QEP's total revenues. Management believes that the loss of any of these customers, or any other customer, would not have a material effect on the financial position or results of operations of QEP, since there are numerous potential purchasers of its production. Refer to Part I, Item 1A- Risk Factors, in this Annual Report on Form 10-K for additional discussion of QEP's competition.

Year Ended December 31, 2018	
Occidental Energy Marketing	16%
Plains Marketing LP	12%
Year Ended December 31, 2017	
Shell Trading Company	14%
Occidental Energy Marketing	13%
Andeavor Logistics LP	13%
BP Energy Company	10%
Plains Marketing LP	10%
Year Ended December 31, 2016	
Shell Trading Company	14%
BP Energy Company	10%
Valero Marketing & Supply Company	10%

Competition

QEP faces competition in every facet of its business, including the acquisition of producing leaseholds, wells and undeveloped leaseholds, the marketing of oil and condensate, gas and NGL products and the procurement of goods, services and labor. The Company's competitors include national oil companies, major integrated oil and gas companies, independent oil and gas companies, individual producers, gas marketers and major pipeline companies, as well as participants in other industries supplying energy, fuel and services to consumers.

Employees

At December 31, 2018 and 2017, QEP had 465 and 656 employees, respectively. None of QEP's employees are represented by unions or covered by collective bargaining agreements.

Executive Officers of the Registrant

The name, age, period of service, title and business experience of each of QEP's executive officers as of February 15, 2019, are listed below:

Timothy J. Cutt	58	President and Chief Executive Officer (January 2019 to present). Prior to joining QEP, Mr. Cutt was the Chief Executive Officer of Cobalt International Energy, a development-stage petroleum exploration and production company (2016 to 2018). Cobalt International voluntarily filed a petition for relief under Chapter 11 of the United States Bankruptcy Code on December 14, 2017, and a plan to sell all the assets of the company was approved on April 10, 2018. Prior to joining Cobalt International, Mr. Cutt served as President of the Petroleum Division of BHP Billiton, a global natural resources company (2013 to 2016), and prior to that he also served as President of Production for BHP Billiton's Petroleum Division (2007 to 2011). Prior to joining BHP Billiton, Mr. Cutt served in various roles at ExxonMobil in the prior 25 years, including President of ExxonMobil de Venezuela (2005 to 2007), President ExxonMobil Canada Energy (2004 to 2005), President Hibernia Management & Development Company (2001 to 2004) and Regional Coordinator, North America (2000 to 2001).
Richard J. Doleshek	60	Executive Vice President and Chief Financial Officer (2010 to present). Treasurer (2010 to 2014). Chief Accounting Officer (2013 to 2014). Previous titles with Questar Corporation: Executive Vice President and Chief Financial Officer (2009 to 2010). Prior to joining Questar, Mr. Doleshek was Executive Vice President and Chief Financial Officer at Hilcorp Energy Company (2001 to 2009).
Christopher K. Woosley	49	Senior Vice President and General Counsel (2017 to present). Vice President and General Counsel (2012 to 2016). Corporate Secretary (2016 to 2017). Senior Attorney (2010 to 2012). Prior to joining QEP, Mr. Woosley was a partner in the law firm Cooper Newsome & Woosley PLLP (2003 to 2010).
Jeffery R. Tommerup	65	Senior Vice President, Eastern Region & HSE (2016 to present). Vice President, Production & HSE (2015 to 2016). Vice President, Southern Region (2009 to 2015). Previous titles with Questar: Vice President of the Southern Region (2009-2010), General Manager of Drilling Operations for the Southern Region (2008-2009), General Manager of the Uinta Division (2005-2008), Manager of Tulsa (2003-2005), Drilling Superintendent for Tulsa and Oklahoma City. Prior to joining Questar, Mr. Tommerup was Engineering Manager at Sunlight Exploration (2000-2002), served in various drilling and reservoir manager roles at Maxus Energy (1987-2000) and was a production engineer for Diamond Shamrock (1982-1987).
Joseph T. Redman	41	Vice President, Western Region (2017 to present). General Manager (2012-2017). Operations and Engineering Manager (2010-2012). Previous titles with Questar Corporation: Staff Petroleum Engineer/Supervisor ((2010). Senior Petroleum Engineer (2008-2010). Reservoir Engineer (2006-2008). Prior to joining Questar, Joe worked in the pipeline industry.

There is no family relationship between any of the listed officers or between any of them and the Company's directors. The executive officers serve at the pleasure of the Company's Board of Directors. There is no arrangement or understanding under which any of the officers were selected.

Government Regulation

QEP's business operations are subject to a wide range of local, state, tribal and federal statutes, rules, orders and regulations. The regulatory environment in which the oil and gas industry operates increases the cost of doing business and consequently affects profitability. Due to the myriad of complex federal, state, tribal and local regulations that may directly or indirectly affect QEP, the following discussion of certain laws and regulations should not be considered an exhaustive review of all regulatory considerations affecting QEP's operations. See additional discussion of regulations under Part I, Item 1A – Risk Factors, in this Annual Report on Form 10-K.

Regulation of Exploration and Production Activities

The regulation of oil and gas E&P activities is a broad and increasingly complex area, notably including laws and regulations governing the potential discharge or release of materials into the environment or otherwise relating to environmental protection. These laws and regulations include, but are not limited to, the following:

Clean Air Act. The federal Clean Air Act and similar state laws regulate the emission of air pollutants from equipment and facilities employed by QEP in its business, including, but not limited to, engines, tanks and dehydrators. In 2012 and 2016, the Environmental Protection Agency (EPA) adopted various regulations specific to oil and gas exploration, production, gathering and processing, which impose air quality controls and work practices, and govern source determination and permitting requirements, and methane emissions. In September 2018, the EPA announced proposed revisions to the various regulations which may reduce compliance burdens on some facilities, but the regulatory uncertainty surrounding the implementation of such revisions and the potential for legal challenges to them pose some complications for QEP's ongoing operations and compliance efforts. Additionally, many states are adopting air permitting and other air quality control regulations specific to oil and gas exploration, production, gathering and processing that are more stringent than existing requirements under federal regulations. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues.

In June 2016, the EPA issued a Federal Implementation Plan (FIP) to implement the Federal Minor New Source Review Program on tribal lands for oil and gas production. The FIP primarily impacts QEP's operations on the Fort Berthold Reservation in the Williston Basin. The FIP creates a permit-by-rule process for minor sources that also incorporates emission limits and other requirements under various federal air quality standards, applying them to a range of equipment and processes used in oil and gas production and gathering.

Greenhouse Gas Regulations and Climate Change Legislation. In recent years, the EPA has adopted and substantially expanded regulations for the measurement and annual reporting of carbon dioxide, methane and other greenhouse gases (GHG) emitted from certain large facilities, including onshore oil and gas production, processing, transmission, storage and distribution facilities. In addition, both houses of Congress have considered legislation to reduce emissions of GHG, and a number of states have taken, or are considering taking, legal measures to reduce emissions of GHG, primarily through the development of GHG inventories, GHG permitting, state or regional GHG cap and trade programs, and/or mandates for the use of renewable energy.

Bureau of Land Management Venting and Flaring Regulations. In November 2016, the Department of the Interior's Bureau of Land Management (BLM) finalized a rule to further control the venting, flaring and emission of natural gas on BLM and tribal leases (2016 Waste Prevention Rule). In September 2018, the BLM finalized a rule that revised and replaced the 2016 Waste Prevention Rule, effective November 2018 (Revised Waste Prevention Rule). The Revised Waste Prevention Rule rescinds certain provisions of the 2016 Waste Prevention Rule, revises other provisions of the 2016 Waste Prevention Rule, and adds provisions deeming gas vented or flared in accordance with applicable state or tribal requirements to be royalty free. Environmental nongovernmental organizations (ENGOs) and certain states have challenged the Revised Waste Prevention Rule in the U.S. District Court for the Northern District of California, and industry groups have intervened in that action.

Other BLM Regulations. In November 2016, the BLM finalized regulations that update and replace Onshore Orders No. 3 (Site Security), No. 4 (Measurement of Oil) and No. 5 (Measurement of Gas). These regulations increase compliance burdens on federal lessees and operators like QEP by requiring such lessees or operators to obtain numbers for all onshore points of federal royalty measurement from the BLM, adjusting recordkeeping requirements, and by imposing new oil and gas measurement equipment standards, among other requirements, for production from federal and Indian leases. Although these regulations took effect in January 2017, the BLM has delayed the requirement to obtain numbers for all onshore points of federal royalty measurement.

Clean Water Act and Safe Drinking Water Act. The federal Clean Water Act and similar state laws regulate discharges of wastewater, oil, fill material, and other pollutants into regulated "waters of the United States" (or WOTUS). These laws also require the preparation and implementation of Spill Prevention, Control, and Countermeasure Plans in connection with on-site storage of significant quantities of oil. The scope of what areas constitute jurisdictional waters of the United States regulated under the Clean Water Act is currently entangled in ongoing litigation and related administrative matters that are not expected to be resolved for several years, and additional litigation and administrative proceedings are expected in the future. In the meantime, the EPA and the U.S. Army Corps of Engineers (Corps) are expected to determine the scope of such regulated areas much as they have over the last decade. In December 2018, the EPA and the Corps announced a revised definition that would clarify waters of the U.S. (subject to federal Clean Water Act jurisdiction) which definition does not include ephemeral streams or isolated wetlands. Areas regulated under comparable state laws are generally defined more broadly. The federal Safe Drinking Water Act (SDWA) and comparable state statutes strictly regulate the disposal of wastes via underground injection wells, including the disposal of produced water and other fluids generated during oil and gas production well development, to protect drinking water resources.

In January 2017, the Corps issued revised and renewed streamlined general nationwide permits that are available to satisfy permitting requirements for certain work in streams, wetlands and other waters of the United States under Section 404 of the Clear Water Act and Section 10 of the Rivers and Harbors Act. The new nationwide permits took effect in March 2017, or when certified by each state, whichever was later. The oil and gas industry broadly utilizes nationwide permits 12, 14, and 39 for the construction, maintenance and repair of pipelines, roads, and drill pads, respectively, and related structures in waters of the United States that impact less than a half-acre of waters of the United States and meet the other criteria of each nationwide permit. Other regional and statewide general permits are available in certain states that also authorize such activities under those statutes.

Oil Pollution Act of 1990. The federal Oil Pollution Act of 1990 (OPA) and regulations issued under the OPA impose strict, joint and several liability on "responsible parties" for removal costs and damages to natural resources resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States.

Comprehensive Environmental Response, Compensation and Liability Act of 1980. The federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA or Superfund) and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons who contributed to the release of a "hazardous substance" into the environment. Such responsible persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances released into the environment and for damage to natural resources. Such liability is in addition to claims for personal injury and property damage caused by the release of hazardous substances into the environment, which may also be made by third parties.

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act (RCRA) is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements on a person who is either a "generator" or "transporter" of hazardous waste or an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility. RCRA and many state counterparts specifically exclude from the definition of hazardous waste "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of oil, gas or geothermal energy." Any repeal or modification of this RCRA oil and gas exploration and production waste exemption would increase the volume of hazardous waste QEP is required to manage and dispose of and would cause QEP, as well as its competitors, to incur increased operating expenses. In December 2016, the U.S. District Court for the District of Columbia approved a consent decree between the EPA and a coalition of ENGOs. The consent decree requires the EPA to review and determine whether it will revise the RCRA regulations for exploration and production waste to treat such waste as hazardous waste. The EPA must complete its review and make its decision regarding revision by March 2019. If the EPA chooses to revise the applicable RCRA regulations, it must sign a notice taking final action related to the new regulation by July 2021.

Hydraulic Fracturing Regulations. QEP's current and future production and oil and gas reserves are derived from reservoirs that require hydraulic fracture stimulation to be commercially viable. Hydraulic fracture stimulation involves pumping fluid at high pressure into tight sand or shale reservoirs to artificially induce fractures. The artificially induced fractures allow better connection between the wellbore and the surrounding reservoir rock, thereby enhancing the productive capacity and ultimate hydrocarbon recovery of each well. The fracture stimulation fluid is typically composed of over 99% water and sand, with the remaining constituents consisting of chemical additives designed to optimize the fracture stimulation treatment and production from the reservoir. QEP discloses the contents of hydraulic fracturing fluids and submits information regarding its wells and the fluids used in them, to the national online disclosure registry, FracFocus (www.fracfocus.org), and to state registries where required.

QEP obtains water for fracture stimulations from a variety of sources, including industrial water wells and surface water sources. When technically and economically feasible, QEP recycles flow-back and produced water for use in fracture stimulation, which reduces water consumption from surface and groundwater sources and reduces produced water disposal volumes. QEP also employs additional measures, when available, to protect water quality such as using hydrocarbon free lubricants in water well construction, locking all inactive water wells to prevent unauthorized use, and transporting both fresh and produced water by pipeline instead of truck when feasible to avoid truck traffic and emissions. QEP believes that the employment of fracture stimulation technology does not present any significant additional risks other than those associated with the disposal of waste water (see Item 1A - Risk Factors for more information) and those generally associated with oil and gas drilling, completion and production operations, such as the risk of spills, releases, discharges, accidents and injuries to persons and property.

Almost all oil and gas producing states require disclosure of the chemicals used in hydraulic fracturing and some form of reporting after a well is fractured. Some states have adopted additional requirements for hydraulic fracturing, such as notice to the surface owner or others, wellbore testing, ground water sampling, waste handling, and seismic monitoring. Other states rely for this purpose upon their existing regulatory programs for permitting wells, ensuring wellbore integrity, managing waste, and overseeing oil and gas development. A few states have imposed moratoria on hydraulic fracturing, but QEP does not operate in those states.

Federal regulation of hydraulic fracturing is currently limited but evolving. The EPA has regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the SDWA, but QEP does not use diesel fuel in any of its hydraulic fracturing fluids. In recent years, the EPA has adopted pretreatment standards under the Clean Water Act for hydraulic fracturing effluent, issued an advance notice of proposed rulemaking under the Toxic Substances Control Act to obtain data on hydraulic fracturing chemicals, and published a multi-year study on potential impacts to drinking water from hydraulic fracturing. Also, in 2016, the Occupational Safety and Health Administration (OSHA) adopted employee-protection requirements regarding silica, which is used in hydraulic fracturing fluids.

In the event that new or more stringent federal, state or local regulations, restrictions or moratoria are adopted in areas where QEP operates, QEP could incur potentially 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 or stimulating wells in some areas.

Tribal Lands and Minerals. Various federal agencies within the U.S. Department of the Interior, particularly the BLM and the Bureau of Indian Affairs (BIA), along with certain Native American tribes, promulgate and enforce regulations pertaining to oil and gas operations on Native American tribal lands and minerals where QEP operates. These regulations include, but are not limited to, such matters as lease provisions, drilling and production requirements, surface use restrictions, environmental standards, royalty considerations and taxes. In March 2016, the BIA implemented regulations significantly altering the procedure for obtaining rights-of-way on tribal lands. In certain cases, these new regulations have increased the time and cost required to obtain necessary rights-of-ways for operation on tribal lands for QEP and its competitors.

Endangered Species Act and National Environmental Policy Act. To develop federal or Indian leases, QEP must obtain authorizations from federal agencies, such as drilling permits and rights-of-way. Prior to issuing such authorizations, federal agencies must comply with both the Endangered Species Act and National Environmental Policy Act (NEPA). The Endangered Species Act restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal or permanent ban in affected areas. NEPA requires that federal agencies assess the direct, indirect and cumulative environmental impacts of their authorizations. This analysis is done in Environmental Assessments or Environmental Impact Statements prepared for a lead agency under the Council on Environmental Quality and other agency regulations, usually for the BLM in the areas where QEP operates.

Emergency Planning and Community Right-to-Know Act and Occupational Safety and Health Act. Pursuant to the Emergency Planning and Community Right-to-Know Act (EPCRA), facilities that store, use or release certain chemicals are subject to various reporting requirements. EPCRA requirements include emergency planning notification, emergency release notification, and emergency and chemical inventory reporting to state and local emergency planning committees and emergency response departments. In January 2017, the EPA proposed to add natural gas processing facilities to the list of industrial facilities that must report under EPCRA's Toxic Release Inventory, but the proposed rule has not been finalized. OSHA establishes workplace standards for the protection of the health and safety of employees, including the implementation of a hazard communication program designed to inform all downstream users, including employees, about hazardous chemicals in the workplace, potential harmful effects of these chemicals, and appropriate control measures.

Transportation Regulations

Regulation of the Transportation and Sale of Natural Gas. The FERC regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 (Natural Gas Act) and the Natural Gas Policy Act of 1978 and regulations issued under those Acts. Under the Energy Policy Act of 2005, the FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties. The gathering of natural gas is exempt from FERC regulation under the Natural Gas Act (referred to as "non-jurisdictional" gatherer and gathering lines/systems). However, there is no bright-line test for determining jurisdictional status. Under FERC's current regulatory regime, transmission services must be provided on an open-access, non-discriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Our gas gathering system is not currently subject to state public utility regulations.

Regulation of Interstate Crude Oil Pipelines. Some of QEP's crude oil pipelines are subject to regulation by the Texas Railroad Commission (TRRC). The applicable state statutes require that pipeline rates be nondiscriminatory and provide no more than a fair return on the aggregate value of the pipeline property used to render services. QEP's crude oil pipelines (specifically the rates, terms and conditions for shipments) may also be subject to FERC regulation if QEP's crude oil pipelines provide part of the movement in interstate commerce for shippers (pursuant to the Interstate Commerce Act, as it existed on October 1, 1977, the Energy Policy Act of 1992 and related rules). QEP does not control the entire transportation path of all crude oil shipped on QEP's pipelines. Therefore, FERC regulation could be triggered by QEP's customers' transportation decisions.

Regulation of Pipeline Safety. QEP's pipeline operations are subject to regulation by the Department of Transportation, through the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended (NGPSA), with respect to natural gas and the Hazardous Liquids Pipeline Safety Act of 1979, as amended (HLPSA), with respect to crude oil. The NGPSA and HLPSA, as amended, govern the design, installation, testing, construction, operation, replacement and management of natural gas as well as crude oil, NGL and condensate pipeline facilities. The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 and the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 amended the NGPSA in an effort to reform PHMSA and to close potential gaps in federal pipeline safety regulation, as well as to increase the penalties for violations. Following those acts, PHMSA has proposed numerous changes to its regulations under the NGPSA, including expanding the scope of safety regulation of gathering pipelines. Historically, our pipeline safety compliance costs have not had a material adverse effect on our results of operations.

Transporting Crude Oil by Rail. QEP sells crude oil to customers that may transport crude oil by rail. In May 2015, the U.S. Department of Transportation issued a final rule regarding the safe transportation of flammable liquids by rail. The final rule imposes certain requirements on "offerors" of crude oil, including sampling, testing and certification requirements to improve classification of energy products placed into transport.

State Regulations

The states where QEP operates have promulgated extensive and complex regulations that govern oil and gas development within their respective boundaries. These regulations generally increase the cost of constructing, operating, producing and abandoning wells, and violations may result in civil penalties and affect QEP's ability to operate. The following are examples of these state regulations.

Texas. In 2014, the TRRC adopted new permit rules for injection wells to address seismic activity concerns within the state. Among other things, the rules require companies seeking permits for produced water disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the TRRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. Also in 2014, the TRRC adopted additional well integrity, casing, and cementing requirements for hydraulically fractured wells. In 2016, the TRRC conformed its administrative practices and procedures for horizontally drilled and hydraulically fractured well fields to those applicable to other types of oil and gas well development.

North Dakota. The North Dakota Industrial Commission (NDI Commission), North Dakota's chief energy regulator, issued an order in June 2014 to reduce the volume of natural gas flared from oil wells in the Bakken and Three Forks formations. In connection with that order, the NDI Commission required operators to develop gas capture plans that describe how much natural gas is expected to be produced, how it will be delivered to a processor and where it will be processed. Production caps or penalties may be imposed on certain well operators that cannot meet the capture goals. In addition, pursuant to Commission Order No. 25417 QEP is required to condition crude oil produced in the Bakken Petroleum System to remove lighter, volatile hydrocarbons and reduce the vapor pressure of crude oil prior to rail transport. In 2018, the NDI Commission amended its gas capture policy to provide flexibility for operators to manage their operations within the gas capture goals set by the commission.

ITEM 1A. RISK FACTORS

Described below are certain risks that we believe are applicable to our business and the oil and gas industry in which we operate. Investors should read carefully the following factors as well as the cautionary statements referred to in "Forward-Looking Statements" herein. If any of the risks and uncertainties described below or elsewhere in this Annual Report on Form 10-K actually occur, the Company's business, financial condition or results of operations could be materially adversely affected.

Our business could be negatively affected as a result of actions of activist shareholders, and such activism could impact the strategic direction of QEP and the trading value of our securities. Elliott Management Corporation (Elliott), a beneficial holder of approximately 4.9% of our common stock (based on Elliott's Form 13F-HR filed on February 14, 2019), made a proposal to our Board on January 7, 2019, to acquire all shares of our common stock for $8.75 per share. Our Board is currently evaluating the proposal and has made the decision to engage in a process to explore strategic alternatives. Activities of activist shareholders could adversely affect our business and/or operations because:

- responding to actions by activist shareholders could be costly and time-consuming, disrupting our operations and diverting the attention of our management and employees;
- such activities could interfere with our ability to execute our strategic plan or realize short- or long-term value from our assets;
- such activities could interfere with our ability to pursue strategic alternatives to Elliott's proposal; and
- the perceived uncertainties as to our future direction could also result in the loss of potential business opportunities, make it more difficult or costly to attract and retain qualified personnel and affect the market price and volatility of our securities.

We are exploring and evaluating strategic alternatives and there can be no assurance that we will be successful in identifying or completing any strategic alternative or that any such strategic alternative will yield additional value for our shareholders. Our Board has commenced a review of strategic alternatives to maximize shareholder value, which could result in a merger or sale of the Company or other transaction involving the Company or its assets. There can be no assurance that the exploration of strategic alternatives will result in the identification or consummation of any transaction or transactions or that any resulting plans or transactions will yield additional value for shareholders. In addition, we may incur substantial expenses associated with identifying and evaluating potential strategic alternatives. The process of exploring strategic alternatives may be time consuming and disruptive to our business operations, may impair our ability to retain and motivate key personnel and could cause third parties that deal with QEP to defer entering into contracts or making other decisions or seek to change existing business relationships. Our business, financial condition and results of operations could be adversely affected by the process. Any potential transaction would be dependent upon a number of factors that may be beyond our control, including, among other factors, market conditions, industry trends, regulatory limitations and the interest of third parties in our business.

The divestiture of our assets in the Uinta Basin and Haynesville/Cotton Valley and the termination of our Planned Williston Basin Divestiture could materially adversely affect our business, financial position, results of operations or cash flows or the prices of our securities. In September 2018, we sold our Uinta Basin assets. In November 2018, we entered into agreements to sell our Haynesville/Cotton Valley assets and our Williston Basin assets. In January 2019, we closed the sale of our Haynesville/Cotton Valley assets. In February 2019, the purchase and sale agreement related to the Planned Williston Basin Divestiture was terminated. Organizational modifications due to these transactions and our other strategic changes can alter risk and control environments; disrupt ongoing business; distract management and employees; increase expenses; result in additional liabilities, investigations and litigation; harm corporate strategy; and adversely affect results of operations. Even if these challenges are dealt with successfully, the anticipated benefits of the divestitures may not be realized. As a result of the termination of the purchase and sale agreement related to the Planned Williston Basin Divestiture, we will not realize the expected benefits of the proposed sale, and we have incurred transaction costs, including legal, accounting, financial advisory and other costs relating to the Planned Williston Basin Divestiture, a portion of which will not be reimbursed in accordance with the terms of the purchase and sale agreement. The sale of our Uinta Basin and Haynesville/Cotton Valley assets and the termination of the Planned Williston Basin Divestiture could materially adversely affect our business, financial position, results of operations and cash flows.

In addition our operations are now limited to oil producing properties located in the Permian and Williston basins. As a result of our lack of diversification in asset type and our limited geographic diversification, any delays or interruptions of production caused by such factors as governmental regulation; transportation capacity constraints; curtailment of production or interruption of transportation; price fluctuations; natural disasters; or shutdowns of the pipelines connecting our production to refineries would have a significantly greater impact on our results of operations than if we possessed more diverse assets and locations.

The prices for oil, gas and NGL are volatile, and declines in such prices could adversely affect QEP's earnings, cash flows, asset values and stock price. Historically, oil, gas and NGL prices have been volatile and unpredictable, and that volatility is expected to continue. Volatility in oil, gas and NGL prices is due to a variety of factors that are beyond QEP's control, including:

- changes in local, regional, domestic and foreign supply of and demand for oil, gas and NGL;
- the impact of an abundance of oil, gas and NGL from unconventional sources on the global and local energy supply;
- the level of imports and/or exports of, and the price of, foreign oil, gas and NGL;
- localized supply and demand fundamentals, including the proximity, cost and availability of pipelines and other transportation facilities, and other factors that result in differentials to benchmark prices from time to time;
- the availability of refining and storage capacity;
- domestic and global economic and political conditions;
- changes in government energy policies, including imposed price controls or product subsidies or both;
- speculative trading in crude oil and natural gas derivative contracts;
- the continued threat of terrorism and the impact of military and other action;
- the activities of the Organization of Petroleum Exporting Countries (OPEC) and other oil producing countries such as Russia, including the ability of members of OPEC and Russia to maintain oil price and production controls;
- political and economic conditions and events in the United States and in or affecting other producing countries, including events in the Middle East, Africa, South America and Russia;
- the strength of the U.S. dollar relative to other currencies;
- weather conditions and natural disasters;
- domestic and international laws, regulations and taxes, including regulations or legislation relating to climate change, induced seismicity or oil and gas exploration and production activities;
- technological advances affecting energy consumption and energy supply;
- conservation efforts;
- the price, availability and acceptance of alternative energy sources, including coal, nuclear energy, renewables and biofuels;
- demand for electricity and natural gas used as fuel for electricity generation;
- the level of global oil, gas and NGL inventories and exploration and production activity; and
- the quality of oil and gas produced.

Declines in oil or natural gas prices would not only reduce revenue, but could also reduce the amount of oil and natural gas that we can economically produce and therefore potentially lower our oil and gas reserve quantities. In addition, the decline in oil and gas prices in the fourth quarter of 2018 and continuing volatility in the first quarter of 2019 could negatively impact our ability to execute our operating and development plans or strategic initiatives.

The long-term effect of factors impacting the prices of oil, gas and NGL is uncertain. Substantial or prolonged declines in these commodity prices may have the following effects on QEP's business:

- adversely affect QEP's financial condition and liquidity and QEP's ability to finance planned capital expenditures, borrow money, repay debt and raise additional capital;
- reduce the amount of oil, gas and NGL that QEP can produce economically;
- cause QEP to delay, postpone or cancel some of its capital projects;
- cause QEP to divest properties to generate funds to meet cash flow or liquidity requirements;
- reduce QEP's revenues, operating income or cash flows;
- reduce the amounts of QEP's estimated proved oil, gas and NGL reserves;
- reduce the carrying value of QEP's oil and gas properties due to recognizing additional impairments of proved and unproved properties;
- limit QEP's access to, or increasing the cost of, sources of capital such as equity and long-term debt;
- cause additional counterparty credit risk;
- decrease the value of QEP's common stock; and
- increase shareholder activism.

Alternatively, higher oil prices may result in increased volatility in commodity prices, inflation, slower economic growth, a global recession or more international conflicts. Higher oil prices may also result in higher costs for QEP and significant mark-to-market losses being incurred in QEP's commodity derivatives, which may in turn cause us to experience net losses.

Lower oil, gas and NGL prices or negative adjustments to oil, gas and NGL reserves may result in significant impairment charges. Lower commodity prices may not only decrease QEP's revenues, operating income and cash flows but also may reduce the amount of oil, gas and NGL that QEP can produce economically. GAAP requires QEP to write down, as a non-cash charge to earnings, the carrying value of its oil and gas properties in the event QEP has impairments. QEP is required to perform impairment tests on its assets periodically and whenever events or changes in circumstances warrant a review of its assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of its assets, the carrying value may not be recoverable, and, therefore, a write-down may be required. During the years ended December 31, 2018, 2017 and 2016, QEP recorded impairment charges of $1,524.6 million, $38.1 million and $1,172.7 million, respectively, on its proved properties and $36.3 million, $29.0 million and $17.9 million, respectively, on its unproved properties. QEP also recorded an impairment of $6.5 million on its underground gas storage facility during the year ended December 31, 2017 and goodwill impairment of $5.3 million and $3.7 million during the years ended December 31, 2017, and 2016, respectively. Refer to Part I, Item 8, Note 1 – Summary of Significant Accounting Policies, of this Annual Report on Form 10-K for more information.

If forward oil prices decline from December 31, 2018 levels or we experience negative changes to the estimated reserve quantities, we have proved and unproved properties at risk for impairment. The actual amount of impairment incurred, if any, for these properties will depend on a variety of factors including, but not limited to, subsequent forward price curve changes, the additional risk-adjusted value of probable and possible reserves associated with the properties, weighted-average cost of capital, operating cost estimates and future capital expenditure estimates.

The Company may not be able to economically find and develop new reserves. The Company's liquidity and profitability depends not only on prevailing prices for oil, gas and NGL, but also on its ability to find, develop and acquire oil and gas reserves that are economically recoverable. Producing oil and gas reservoirs are generally characterized by declining production rates that vary depending on reservoir characteristics. Because oil and gas production volumes from unconventional wells typically experience relatively steep declines in the first year of operation and continue to decline over the economic life of the well, QEP must continue to invest significant capital to find, develop and acquire oil and gas reserves to replace those depleted by production. Failure to find or acquire additional reserves would cause reserves and production to decline materially from their current levels.

Oil and gas reserve estimates are imprecise, may prove to be inaccurate, and are subject to revision. Any significant inaccuracies in QEP's reserve estimates or underlying assumptions may negatively affect the quantities and present value of QEP's reserves. QEP's proved oil and gas reserve estimates are prepared annually by independent reservoir engineering consultants. Oil and gas reserve estimates are subject to numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and timing of development expenditures. The accuracy of these estimates depends on the quality of available data and on engineering, geological and geophysical interpretation and judgment. Reserve estimates are imprecise and will change as more information becomes available. Estimates of economically recoverable reserves and future net cash flows prepared by different engineers or by the same engineers at different times may vary significantly. Results of subsequent drilling, testing and production may cause either upward or downward revisions of previous estimates. In addition, the estimation process involves economic assumptions relating to commodity prices, operating costs, severance and other taxes, capital expenditures and remediation costs. Actual results most likely will vary from the estimates. Any significant variance from these assumptions could affect the recoverable quantities of reserves attributable to any particular property, the classifications of reserves, the estimated future net cash flows from proved reserves and the present value of those reserves.

Investors should not assume that QEP's presentation of the Standardized Measure of Discounted Future Net Cash Flows relating to Proved Reserves in this Annual Report on Form 10-K is reflective of the current market value of the estimated oil and gas reserves. In accordance with SEC disclosure rules, the estimated discounted future net cash flows from QEP's proved reserves are based on the first-of-the-month prior 12-month average prices and current costs on the date of the estimate, holding the prices and costs constant throughout the life of the properties and using a discount factor of 10% per year. QEP's cost estimates do not include any carbon pollution costs associated with climate change damages. Actual future production, prices and costs may differ materially from those used in the current estimate, and future determinations of the Standardized Measure of Discounted Future Net Cash Flows using similarly determined prices and costs may be significantly different from the current estimate. Therefore, reserve quantities may change when actual prices increase or decrease. In addition, the 10% discount factor QEP uses when calculating discounted future net cash flows in accordance with SEC disclosure rules, may not be the most appropriate discount factor that is based on interest rates in effect from time to time and risks associated with the Company or the oil and gas industry in general.

In addition, realization or recognition of proved undeveloped reserves will depend on QEP's development schedule and plans. A change in future development plans for proved undeveloped reserves could cause the discontinuation of the classification of those reserves as proved. See Items 1 and 2. Business and Properties – Proved Reserves in this Annual Report on Form 10-K.

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, 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 producible hydrocarbons are, in fact, present in those structures in economic quantities. 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.

Shortages of qualified personnel and/or oilfield equipment and services could impact results of operations. The oil and gas industry has long suffered a skills shortage, recognized by many to be a threat to future growth. This skills shortage has been exacerbated by depressed oil and gas prices in the last three years and the resulting loss of skilled workers through layoffs in the oil and gas industry during these years. The demand for and availability of qualified and experienced personnel to drill wells and conduct field operations, in addition to geologists, geophysicists, engineers, landmen and other professionals in the oil and gas industry, will create challenges for QEP and its competitors and may cause periodic and problematic personnel shortages. In periods of high commodity prices, there have also been regional shortages of drilling rigs and other equipment. Any cost increases could impact profit margin, cash flow and operating results or restrict QEP's ability to drill wells and conduct operations.

QEP's operations are subject to operational hazards and unforeseen interruptions for which QEP may not be adequately insured and that could adversely affect our business, financial condition and results of operations. There are operational risks associated with the exploration, production, gathering, transporting, and storage of oil, gas and NGL, including:

- injuries and/or deaths of employees, supplier personnel, or other individuals;
- fire, explosions and blowouts;
- earthquakes and other natural disasters;
- aging infrastructure and mechanical problems;
- unexpected drilling conditions, including abnormally pressured formations or loss of drilling fluid circulation;
- pipe, cement or casing failures;
- equipment malfunctions, mechanical failures or accidents;
- theft or vandalism of oilfield equipment and supplies, especially in areas of increased activity;
- adverse weather conditions;
- plant, pipeline, railway and other facility accidents and failures;
- truck and rail loading and unloading problems;
- delays imposed by or resulting from compliance with regulatory requirements;
- delays in or limits on the issuance of drilling permits on our federal leases, including as a result of government shutdowns;
- environmental accidents such as oil spills, natural gas leaks, pipeline or tank ruptures, or discharges of air pollutants, brine water or well fluids into the environment;
- security breaches, cyberattacks, piracy, or terrorist acts;
- pipeline takeaway and refining and processing capacity issues; and
- title problems.

QEP could incur substantial losses as a result of injury to or loss of life, pollution or other environmental damage, damage to or destruction of property or equipment, regulatory compliance investigations, fines or curtailment of operations, or attorneys' fees and other expenses incurred in the prosecution or defense of litigation. As a working interest owner in wells operated by other companies, QEP may also be exposed to the risks enumerated above from operations that are not within its care, custody or control.

Consistent with industry practice, QEP generally indemnifies drilling contractors and oilfield service companies (collectively, contractors) against certain losses suffered by QEP as the operator and certain third parties resulting from a well blowout or fire or other uncontrolled flow of hydrocarbons, regardless of fault. Therefore, QEP may be liable, regardless of fault, for some or all of the costs of controlling a blowout, drilling a relief and/or replacement well and the cleanup of any pollution or contamination resulting from a blowout in addition to claims for personal injury or death suffered by QEP's employees and certain others. QEP's drilling contracts and oilfield service agreements, however, often provide that the contractor will indemnify QEP for claims related to injury and death of employees of the contractor and its subcontractors and for property damage suffered by the contractor and its subcontractors.

QEP's insurance coverage may not be sufficient to cover 100% of potential losses arising as a result of the foregoing risks. QEP has limited or no coverage for certain other risks, such political risk, lost reserves, business interruption, cyber risk, earthquakes, war and terrorism. Although QEP believes the coverage and amounts of insurance that it carries are consistent with industry practice, QEP does not have insurance protection against all risks that it faces because QEP chooses not to insure certain risks, insurance is not available at a level that balances the costs of insurance and QEP's desired rates of return, or actual losses may exceed coverage limits. QEP could sustain significant losses and substantial liability for uninsured risks. The occurrence of a significant event against which QEP is not fully insured could have a material adverse effect on its financial condition, results of operations and cash flows.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application. Our operations involve utilizing some of the latest drilling and completion techniques. Risks that we face while drilling horizontal wells include, but are not limited to, the following:

- spacing of wells to maximize production rates and recoverable reserves;
- landing the wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running casing the entire length of the wellbore;
- being able to run tools and other equipment consistently through the horizontal wellbore; and
- controlling high pressure wells.

Risks that we face while completing our wells include, but are not limited to, our inability to:

- fracture stimulate the planned number of stages;
- run tools the entire length of the wellbore during completion operations;
- successfully clean out the wellbore after completion of the final fracture stimulation stage;
- prevent unintentional communication with other wells; and
- design and maintain efficient artificial lift throughout the life of the well.

QEP began testing the restimulation, or refracturing, of wells in the Williston Basin during 2017. Refracturing an existing well is technically more challenging than fracturing a new well and may result in the loss of the existing producing well.

The use of new horizontal drilling and completion techniques that simultaneously develop multiple producing horizons can add complexity to field development. For example, QEP experienced delays in placing certain wells in the Permian Basin into production during 2017 due to evolution of its "tank-style" completion methodology, which caused shifts in completion timing.

If our drilling and completion activities do not meet our anticipated results or we are unable to execute our drilling and completion program because of capital constraints, lease expirations, limited access to gathering systems, limited takeaway capacity and/or declines in crude oil and natural gas prices, the return on our investment for certain projects 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 gas properties and the value of our undeveloped acreage could decline in the future.

QEP has limited control over the activities on properties it does not operate, which could adversely affect our production, revenues and returns on capital. We operate 94% of our net productive oil and natural gas wells, which represents 98% of our proved developed producing reserves as of December 31, 2018. Other companies operate some of the properties in which QEP has an interest. QEP has limited ability to influence or control the operation or future development of these non-operated properties, including compliance with environmental, safety and other regulations, or the amount or timing of capital expenditures that QEP is required to fund with respect to them. The failure of an operator of QEP's wells to adequately perform operations, an operator's breach of the applicable agreements with QEP or an operator's failure to act in ways that are in QEP's best interest could reduce QEP's production and revenues. QEP's dependence on the operator and other working interest owners to complete these projects and QEP's limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of QEP's targeted returns on capital in drilling or acquisition activities, lead to unexpected future costs, or adversely affect the timing of activities. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator's decisions with respect to the timing and amount of capital expenditures, the period of time over which the operator seeks to generate a return on capital expenditures, inclusion of other participants in drilling wells, and the use of technology, as well as the operator's expertise and financial resources and the operator's relative interest in the field. Operators may also opt to decrease operational activities following a significant decline in, or a sustained period of low, oil or natural gas prices. Because we do not have a majority interest in most wells we do not operate, we may not be in a position to remove the operator in the event of poor performance. Accordingly, while we use reasonable efforts to cause the operator to act in a prudent manner, we are limited in our ability to do so.

Events of force majeure may limit our ability to operate our business and could adversely affect our operating results. The weather, unforeseen events, or other events of force majeure in the areas in which we operate could cause disruptions and, in some cases, suspension of our operations. This suspension could result from a direct impact to our properties or result from an indirect impact by a disruption or suspension of the operations of those upon whom we rely for gathering and transportation. If disruption or suspension were to persist for a long period, our results of operations would be materially impacted.

Multi-well pad drilling may result in volatility in QEP operating results and delay conversion of PUD reserves. QEP utilizes multi-well pad drilling where practical. For example, in the Permian Basin, QEP utilizes "tank-style" development, in which we drill and complete all wells in a given "tank" before any individual well is turned to production. In the Williston Basin, QEP drills multiple wells from a single pad. Wells drilled on a pad are not brought into production until all wells on the pad are drilled and cased and the drilling rig is moved from the location. In addition, existing wells that offset newly drilled wells may be temporarily shut-in during the drilling and completion process. As a result, multi-well pad drilling delays the completion of wells and the commencement of production, which may cause volatility in QEP's operating results from period to period. Existing wells that offset new wells being completed by QEP or offset operators may also need to be temporarily shut-in during the completion process. Such delays and well shut-ins have caused and may continue to cause volatility in QEP's operating results from period to period. In addition, delays in completion of wells may impact planned conversion of PUD reserves to proved developed.

Lack of availability of refining, gas processing, storage, gathering or transportation capacity will likely impact results of operations. The lack of availability of satisfactory oil, gas and NGL gathering and transportation, including trucks, railways and pipelines, gas processing, storage or refining capacity may hinder QEP's access to oil, gas and NGL markets or delay production from its wells. QEP's ability to market its production depends in substantial part on the availability and capacity of gathering, transportation, gas processing facilities, storage or refineries owned and operated by third parties. Although QEP has some contractual control over the transportation of its production through firm transportation arrangements, third-party systems may be temporarily unavailable due to market conditions, mechanical failures, accidents or other reasons. If gathering, transportation, gas processing or storage facilities do not exist near producing wells; if gathering, transportation, gas processing, storage or refining capacity is limited; or if gathering, transportation, gas processing or refining capacity is unexpectedly disrupted, completion activity could be delayed, sales could be reduced, or production shut-in, each of which could reduce profitability. Furthermore, if QEP were required to shut-in wells, it might also be obligated to pay certain demand charges for gathering and processing services, firm transportation charges on interstate pipelines as well as shut-in royalties to certain mineral interest owners in order to maintain its leases; or depending on the specific lease provisions, some leases could terminate. In addition, rail accidents involving crude oil carriers have resulted in new regulations, and may result in additional regulations, on transportation of oil by railway. QEP might be required to install or contract for additional treating or processing equipment for transport of crude oil by rail, which could increase costs. Federal and state regulation of oil and gas production and transportation, tax and energy policies, changes in supply and demand, transportation pressures, damage to or destruction of transportation facilities and general economic conditions could also adversely affect QEP's ability to transport oil and gas.

Certain of QEP's undeveloped leaseholds are subject to lease agreements that will expire over the next several years unless production is established on the acreage or on units containing the acreage or the leases are otherwise renewed or extended. Leases on oil and gas properties typically have a primary term of three to five years after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established or the lease is renewed or extended. If a lease expires or is not renewed before expiration, QEP will lose its right to develop the related reserves. While QEP seeks to actively manage its leasehold inventory by drilling sufficient wells to hold the leases that it believes are material to its operations, QEP's drilling plans are subject to change based upon various factors, including drilling results, oil and gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals.

QEP may be required to write down its proved undeveloped reserve estimates if it is unable to convert those reserves into proved developed reserves within five years. SEC rules require that, subject to limited exceptions, proved undeveloped (PUD) reserves may only be classified as proved reserves if they are from locations scheduled to be drilled within five years after the date of booking. Recovery of PUD reserves requires the expenditure of significant capital and successful drilling operations. QEP may be required to write down its PUD reserves if it is not successful in drilling PUD wells within the required five-year time frame. During 2018 and 2017, QEP removed 22.6 MMboe and 8.7 MMboe, respectively, of PUD reserves that were no longer in the 2018 and 2017 forecasted capital expenditure plans, respectively, and would not be drilled and completed within five years of the initial date of booking of the reserves. At December 31, 2018, approximately 65% of QEP's estimated proved reserves were PUD reserves. These reserve estimates reflect the Company's plans to make significant capital expenditures to convert its PUDs into proved developed reserves, requiring an estimated $4.3 billion during the five years ending December 31, 2023. The estimated development costs may not be accurate; timing to incur such costs may change; development may not occur as scheduled; and results may not be as estimated.

QEP's identified potential well locations are scheduled over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, QEP may not be able to raise the substantial amount of capital that would be necessary to drill its potential well locations. QEP has identified and scheduled well locations to build its multi-year development plan for its existing leaseholds. These well locations represent a significant part of QEP's growth strategy. QEP's ability to drill and develop these locations is impacted by a number of uncertainties, including the ongoing review and analysis of geologic and engineering data, oil and gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, potential interference between infill and existing wells, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water and water disposal facilities, regulatory approvals and other factors. Because of these factors, QEP does not know if the potential well locations it has identified will be drilled or if QEP will be able to produce oil and gas from these or any other potential well locations. In addition, any drilling activities QEP is able to conduct on these potential locations may not be successful or result in QEP's ability to add additional proved reserves to its overall proved reserves or may result in a downward revision of its estimated proved reserves, which could have a material adverse effect on QEP's future business and results of operations.

Renegotiation of gathering, processing and transportation agreements may result in higher costs and/or delays in selling production. Due to market conditions over the past few years, many midstream companies have attempted to renegotiate their gathering, processing and transportation agreements with their upstream counterparties. QEP has periodically been in discussions with its midstream providers. If QEP agrees to renegotiate its midstream agreements, the costs QEP pays for midstream services may increase. If QEP and any of its midstream service providers cannot agree on revised terms to these agreements, the midstream service providers may assert that continued performance of their obligations under these contracts is uneconomic and attempt to terminate or alter the agreements, which could hinder QEP's access to oil, gas and NGL markets, increase costs and/or delay completion of or production from its wells. Disputes over termination or changes to such agreements could result in arbitration or litigation, causing uncertainty about the status of the agreements and further delays.

QEP is required to pay fees to some of its midstream service providers based on minimum volumes regardless of actual volume throughput. QEP has contracts with some third-party service providers for gathering, processing and transportation services with minimum volume delivery commitments. As of December 31, 2018, QEP's aggregate long-term contractual obligation under these agreements was $253.9 million. QEP is obligated to pay fees on minimum volumes to service providers regardless of actual volume throughput. These fees could be significant and may have a material adverse effect on QEP's results of operations.

QEP is dependent on its revolving credit facility and continued access to capital markets to successfully execute its operating strategies. If QEP is unable to make capital expenditures or acquisitions because it is unable to obtain capital or financing on satisfactory terms, QEP may experience a decline in its oil and gas production rates and reserves. QEP is partially dependent on external capital sources to provide financing for certain projects. The availability and cost of these capital sources is cyclical, and these capital sources may not remain available, or QEP may not be able to obtain financing at a reasonable cost in the future. Over the last few years, conditions in the global capital markets have been volatile, making terms for certain types of financing difficult to predict, and in certain cases, resulting in certain types of financing being unavailable. If QEP's revenues decline as a result of lower oil, gas or NGL prices, operating difficulties, declines in production or for any other reason, QEP may have limited ability to obtain the capital necessary to sustain its operations at current levels. In the past, QEP has utilized cash and its revolving credit facility, provided by a group of financial institutions, to meet short-term funding needs. At year end 2018, QEP had $430.0 million of borrowings under its revolving credit facility. QEP's failure to obtain additional financing could result in a curtailment of its operations relating to exploration and development of its prospects, which in turn could lead to a possible reduction in QEP's oil or gas production, reserves and revenues, and could negatively impact QEP's results of operations.

QEP's debt and other financial commitments may limit its financial and operating flexibility. QEP's total debt was approximately $2.5 billion at December 31, 2018. QEP also has various commitments for leases, drilling contracts, derivative contracts, firm transportation, and purchase obligations for services, products and properties. QEP's financial commitments could have important consequences to its business, including, but not limited to, limiting QEP's ability to fund future working capital and capital expenditures, to engage in future acquisitions or development activities, to repurchase shares of its common stock, or to otherwise realize the value of its assets and opportunities fully because of the need to dedicate a substantial portion of its cash flows from operations and proceeds from the divestiture of its assets to payments on its debt or to comply with any restrictive terms of its debt. QEP may be at a competitive disadvantage as compared to similar companies that have less debt. Higher levels of debt may make QEP more vulnerable to general adverse economic and industry conditions. Additionally, the agreement governing QEP's revolving credit facility and the indentures covering QEP's senior notes contain a number of covenants that impose constraints on the Company, including requirements to comply with certain financial covenants and restrictions on QEP's ability to dispose of assets, make certain investments, incur liens and additional debt, and engage in transactions with affiliates. If commodity prices decline and QEP reduces its level of capital spending and production declines or QEP incurs additional impairment expense or the value of the Company's proved reserves declines, the Company may not be able to incur additional indebtedness, may need to repay outstanding indebtedness and may not be in compliance with the financial covenants in its credit agreement in the future. Refer to Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II of this Annual Report on Form 10-K and Note 9 – Debt, in Item 8 of Part II of this Annual Report on Form 10-K for more information regarding the financial covenants and our revolving credit agreement.

A downgrade in QEP's credit rating could negatively impact QEP's cost of and access to capital. Following the closing of the Haynesville Divestiture, QEP's credit ratings were downgraded to BB- by Standard & Poor's Financial Services LLC (S&P), Ba3 by Moody's Investor Services, Inc. (Moody's) and BB- by Fitch Ratings, Inc. (Fitch). Additional downgrades of QEP's credit rating may make it more difficult or expensive for QEP to raise capital from financial institutions or other sources and could require QEP to provide financial assurance of its performance under certain contractual arrangements and derivative agreements. Refer to Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II of this Annual Report on Form 10-K and Note 9 – Debt, in Item 8 of Part II of this Annual Report on Form 10-K for additional information regarding the financial covenants and our revolving credit agreement.

Failure to fund continued capital expenditures could adversely affect QEP's properties. QEP's exploration, development and acquisition activities require capital expenditures to achieve production and cash flows. Historically, QEP has funded its capital expenditures through a combination of cash flows from operations, its revolving credit facility, debt issuances, equity offerings and sales of assets. Future cash flows from operations are subject to a number of variables, such as the level of production from existing wells, prices of oil, gas and NGL, and QEP's success in finding, developing and producing new reserves.

QEP's use of derivative instruments to manage exposure to uncertain prices could result in financial losses or reduce its income. QEP uses commodity price derivative arrangements to reduce exposure to the volatility of oil, gas and NGL prices, and to protect cash flow and returns on capital from downward commodity price movements. QEP's derivative transactions are limited in duration, usually for periods of one to three years. QEP's derivatives portfolio may be inadequate to protect it from prolonged declines in the price of oil or natural gas. To the extent the Company enters into commodity derivative transactions, it may forgo some or all of the benefits of commodity price increases. Furthermore, QEP's use of derivative instruments through which it attempts to reduce the economic risk of its participation in commodity markets could result in increased volatility of QEP's reported results. Changes in the fair values (gains and losses) of derivatives are recorded in QEP's income, which creates the risk of volatility in earnings even if no economic impact to QEP has occurred during the applicable period. QEP has incurred significant unrealized and realized gains and losses in prior periods and may continue to incur these types of gains and losses in the future.

QEP is exposed to counterparty credit risk as a result of QEP's receivables and commodity derivative transactions. QEP has significant credit exposure to outstanding accounts receivable from purchasers of its production and joint working interest owners. This counterparty credit risk is heightened during times of economic uncertainty, tight credit markets and low commodity prices. Because QEP is the operator of a majority of its production and major development projects, QEP pays joint venture expenses and in some cases makes cash calls on its non-operating partners for their respective shares of joint venture costs. These projects are capital intensive and, in some cases, a non-operating partner may experience a delay in obtaining financing for its share of the joint venture costs. Counterparty liquidity problems could result in a delay or collection issues in QEP receiving proceeds from commodity sales or reimbursement of joint venture costs. Credit enhancements, such as parental guarantees, letters of credit or prepayments, have been obtained from some but not all counterparties. Nonperformance by a trade creditor or joint venture partner could result in financial losses. In addition, QEP's commodity derivative transactions expose it to risk of financial loss if the counterparty fails to perform under a contract. During periods of falling commodity prices, QEP's commodity derivative receivable positions increase, which increases its counterparty credit exposure. QEP monitors creditworthiness of its trade creditors, joint venture partners, derivative counterparties and financial institutions on an ongoing basis. However, if one of them were to experience a sudden change in liquidity, it could impair such a party's ability to perform under the terms of QEP's contracts. QEP is unable to predict sudden changes in creditworthiness or ability of these parties to perform and could incur significant financial losses.

The enactment of derivatives legislation, and the promulgation of regulations pursuant thereto, could have an adverse impact on QEP's ability to use derivative instruments to reduce the effect of commodity price volatility and other risks associated with its business. The Dodd-Frank Act, which was signed into law in July 2010, contains significant derivatives regulation, including, among other items, a requirement that certain transactions be cleared on exchanges as well as collateral or "margin" requirements for certain uncleared swaps. The Dodd-Frank Act provides for an exception from these clearing requirements for commercial end-users, such as QEP. The Dodd-Frank Act and the rules promulgated thereunder could significantly increase the cost of derivative contracts (including through requirements to post collateral), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks QEP encounters, reduce QEP's ability to monetize or restructure QEP's existing derivative contracts, increase the administrative burden and regulatory risk associated with entering into certain derivative contracts, and increase QEP's exposure to less creditworthy counterparties. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and gas. QEP revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and its regulations is to lower commodity prices. Any of these consequences could affect the pricing of derivatives and make it more difficult for us to enter into derivative transactions, which could have a material and adverse effect on QEP's business, financial condition and results of operations. The rulemaking and implementation process are ongoing and the ultimate effect of the adopted rules and regulations and any future rules and regulations on QEP's business remains uncertain.

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QEP faces various risks associated with the trend toward increased opposition to oil and gas exploration and development activities. Opposition to oil and gas drilling and development activity has been growing globally and is particularly pronounced in the U.S. Companies in the oil and gas industry, such as QEP, are often the target of activist efforts from both individuals and ENGOs regarding safety, environmental compliance and business practices. Anti-development activists are working to, among other things, reduce access to federal and state government lands and delay or cancel certain projects such as the development of oil or gas shale plays. For example, ENGOs and other environmental activists continue to advocate for increased regulation of shale drilling in the U.S., even in jurisdictions that are among the most stringent in their regulation of the industry. Future activist efforts could result in the following:

- delay or denial of drilling and other necessary permits;
- shortening of lease terms or reduction in lease size;
- restrictions on installation or operation of gathering, processing or pipeline facilities;
- more stringent setback requirements from houses, schools, businesses and other improvements and landscape features;
- towns, cities, states and counties imposing bans on certain activities, including hydraulic fracturing;
- restrictions on the use of certain operating practices, such as hydraulic fracturing, or the disposition of related waste materials, such as hydraulic fracturing fluids and produced water;
- reduced access to water supplies or restrictions on produced water disposal;
- increased severance and/or other taxes;
- cyberattacks;
- legal challenges or lawsuits;
- negative publicity about QEP;
- disinvestment and other targeted activist shareholder campaigns;
- increased costs of doing business;
- reduction in demand for QEP's production;
- other adverse effects on QEP's ability to develop its properties and increase production;
- increased regulation of rail transportation of crude oil;
- opposition to the construction of new oil and gas pipelines;
- postponement of state oil and gas lease sales; and
- delays in or challenges to issuance of federal and tribal oil and gas leases.

QEP may incur substantial costs associated with responding to these initiatives or complying with any resulting additional legal or regulatory requirements that are not adequately provided for, which could have a material adverse effect on its business, financial condition and results of operations.

We may incur losses as a result of title defects in the properties in which we invest. The existence of a material title deficiency can render a lease worthless. In the course of acquiring the rights to develop oil or natural gas, it is standard procedure for us and the lessor to execute a lease agreement with payment, subject to title verification. There is no certainty, however, that a lessor has valid title to their lease's oil and gas interests. In those cases, such leases are generally voided and payment is not remitted to the lessor. As such, title failures may result in fewer net acres to us. Prior to the drilling of an oil or natural gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may delay or prevent us from utilizing the associated mineral interest, which may adversely impact our ability in the future to increase production and reserves. Accordingly, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

QEP faces significant competition and certain of its competitors have resources in excess of QEP's available resources. QEP operates in the highly competitive areas of oil and gas exploration, acquisition and production. QEP faces competition from:

- large multi-national, integrated oil companies;
- U.S. independent oil and gas companies;
- service companies engaging in oil and gas exploration and production activities; and
- private investing in oil and gas assets.

QEP faces competition in a number of areas such as:

- acquiring desirable producing properties or new leases for future exploration;
- acquiring or increasing access to gathering, processing and transportation services and capacity;
- marketing its oil, gas and NGL production;
- obtaining the equipment and expertise necessary to operate and develop properties; and
- attracting and retaining employees with certain critical skills.

Certain of QEP's competitors have financial and other resources in excess of those available to QEP. Such companies may be able to pay more for oil and gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than QEP's financial or human resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than QEP is able to offer. This highly competitive environment could have an adverse impact on QEP's ability to execute its strategy, QEP's financial condition and its results of operations.

QEP may be unable to make acquisitions, successfully integrate acquired businesses and/or assets, or adjust to the effects of divestitures, causing a disruption to its business. One aspect of QEP's business strategy calls for acquisitions of businesses and assets that complement or expand QEP's operations, such as QEP's 2017 Permian Basin Acquisition. QEP cannot provide assurance that it will be able to identify additional acquisition opportunities. Even if QEP does identify additional acquisition opportunities, it may not be able to complete the acquisitions due to capital constraints. Any acquisition of a business or assets involves potential risks, including, among others:

- incorrect estimates or assumptions about reserves, exploration potential or potential drilling locations;
- incorrect assumptions regarding future revenues, including future commodity prices and differentials, or regarding future development and operating costs;
- difficulty integrating the operations, systems, management and other personnel and technology of the acquired business or assets with QEP's own;
- the assumption of unidentified or unforeseeable liabilities, resulting in a loss of value;
- the inability to hire, train or retain qualified personnel to manage and operate QEP's growing business and assets; or
- a decrease in QEP's liquidity to the extent it uses a significant portion of its available cash or borrowing capacity to finance acquisitions or operations of the acquired properties.

Organizational modifications due to acquisitions, divestitures or other strategic changes can alter the risk and control environments; disrupt ongoing business; distract management and employees; increase expenses; result in additional liabilities, investigations and litigation; harm QEP's strategy; and adversely affect results of operations. Even if these challenges can be dealt with successfully, the anticipated benefits of any acquisition, divestiture or other strategic change may not be realized.

In addition, QEP's credit agreement and the indentures governing QEP's senior notes impose certain limitations on QEP's ability to enter into mergers or combination transactions. QEP's credit agreement also limits QEP's ability to incur certain indebtedness, which could limit QEP's ability to engage in acquisitions.

QEP may be unable to divest assets on financially attractive terms, resulting in reduced cash proceeds. QEP has announced that it is evaluating the sale of certain midstream assets. QEP's success in divesting assets depends, in part, upon QEP's ability to identify suitable buyers or joint venture partners; assess potential transaction terms; negotiate agreements; and, if applicable, obtain required approvals. Various factors could materially affect QEP's ability to dispose of assets on terms acceptable to QEP. Such factors include, but are not limited to: current and forecasted commodity prices; current laws, regulations and permitting processes impacting oil and gas operations in the areas where the assets are located; covenants under QEP's credit agreement; tax impacts; willingness of the purchaser to assume certain liabilities such as asset retirement obligations and firm transportation contracts; QEP's willingness to indemnify buyers for certain matters; and other factors.

In addition, QEP's credit agreement contains limitations on the amount of asset sales that it is permitted to divest each year. If QEP seeks to sell more assets than is permitted under the credit agreement and is unable to receive waivers of such restrictions, then it may be unable to divest these assets.

QEP is involved in legal proceedings that could result in substantial liabilities and materially and adversely impact the Company's financial condition. Like many oil and gas companies, the Company is involved in various legal proceedings, including threatened claims, such as title, royalty, and contractual disputes. The cost to settle legal proceedings (asserted or unasserted) or satisfy any resulting judgment against the Company in such proceedings could result in a substantial liability or the loss of interests, which could materially and adversely impact the Company's cash flows, operating results and financial condition. Judgments and estimates to determine accruals or the range of reasonably possible loss related to legal proceedings could change from one period to the next, and such changes could be material. Current accruals may be insufficient. Legal proceedings could result in negative publicity about the Company. In addition, legal proceedings distract management and other personnel from their primary responsibilities.

Failure of the Company's controls and procedures to detect errors or fraud could seriously harm its business and results of operations. QEP's management, including its chief executive officer and chief financial officer, does not expect that the Company's internal controls and disclosure controls will prevent all possible errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are being met. In addition, the design of a control system must reflect the fact that there are resource constraints, and the benefit of controls are evaluated relative to their costs. Because of the inherent limitations in all control systems, no evaluation of QEP's controls can provide absolute assurance that all control issues and instances of fraud, if any, in the Company have been detected. The design of any system of controls is based in part upon the likelihood of future events, and there can be no assurance that any design will succeed in achieving its intended goals under all potential future conditions. Over time, a control may become inadequate because of changes in conditions, or the degree of compliance with its policies or procedures may deteriorate. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur without detection. Violations of any laws or regulations caused by either failure of our internal controls related to regulatory compliance or failure of our employees to comply with our internal policies could result in substantial civil or criminal fines. In addition, legal enforcement may be impacted by significant incentives for whistleblowers.

QEP is subject to complex federal, state, tribal, local and other laws and regulations that could adversely affect its cost of doing business and recording of proved reserves. QEP's operations are subject to extensive federal, state, tribal and local tax, energy, environmental, health and safety laws and regulations. The failure to comply with applicable laws and regulations can result in substantial penalties and may threaten the Company's authorization to operate.

Environmental laws and regulations are complex, change frequently and have tended to become more onerous over time. This regulatory burden on the Company's operations increases its cost of doing business and, consequently, affects its profitability. In addition to the costs of compliance, substantial costs may be incurred to take corrective actions at both owned and previously owned facilities. Accidental spills and leaks requiring cleanup may occur in the ordinary course of QEP's business. As standards change, the Company may incur significant costs in cases where past operations followed practices that were considered acceptable at the time, but now require remedial work to meet current standards. Failure to comply with these laws and regulations may result in fines, significant costs for remedial activities, other damages, or injunctions that could limit the scope of QEP's planned operations.

Clean Air Act regulations at 40 C.F.R Part 60, Subpart OOOO (Subpart OOOO) became effective in 2012, with further amendments effective in 2013 and 2014. Subpart OOOO imposes air quality controls and requirements upon QEP's operations. Additionally, in June 2016, the EPA finalized closely related rules in new Subpart OOOOa to achieve additional methane and volatile organic compound reductions from certain activities in the oil and gas industry. The new rules include, among others, new requirements for finding and repairing leaks at new well sites and "reduced emission completion" requirements for hydraulically fractured oil and gas wells. The future status of Subpart OOOOa remains uncertain given ongoing litigation and administrative regulatory actions. In September 2018, EPA announced proposed revisions to Subpart OOOOa which may reduce compliance burdens on some facilities, but the regulatory uncertainty surrounding the implementation of such revisions and the potential for legal challenges to them pose complications for QEP's operations and compliance efforts. Additionally, many states are adopting air permitting and other air quality control regulations specific to oil and gas exploration, production, gathering and processing that are more stringent than existing requirements under federal regulations and the proposed revisions to such regulations.

In June 2015, the EPA and the Corps issued a new rule that expanded the scope of "waters of the United States" subject to regulation under the federal Clean Water Act. Several courts have temporarily enjoined that rule in 27 states, including Texas and North Dakota. In those states, regulated WOTUS are currently determined under the previous rules and related guidance adopted in 1986. The 2015 WOTUS rule remains in effect in the other 23 states. In December 2018, the agencies proposed a new rule that would differently revise the definition of WOTUS and replace both the 1986 and 2015 WOTUS rules. If finalized, this new definition of WOTUS will likely be challenged and sought to be enjoined in federal court. To the extent any new rule or upheld 2015 rule expands the scope of Clean Water Act regulation, the Company could face increased costs, delays and restrictions in obtaining permits for fill activities or other pollutant discharges in certain areas. The Clean Water Act and related regulations also provide for administrative, civil and criminal penalties for unauthorized discharges of fill material or oil and other pollutants and, in the event of any violation, may impose substantial costs for removal, remediation, fines and damages.

Regulatory requirements to reduce gas flaring and to further restrict emissions could have an adverse effect on our operations. Wells in the Williston Basin of North Dakota and the Permian Basin of Texas, where QEP has significant operations, produce natural gas as well as crude oil. Constraints in third party gas gathering and processing systems in certain areas have resulted in some of that natural gas being flared instead of gathered, processed and sold. In June 2014, the NDI Commission, North Dakota's chief energy regulator, adopted a policy to reduce the volume of natural gas flared from oil wells in the Williston Basin. The NDI Commission requires operators to develop gas capture plans that describe how much natural gas is expected to be produced, how it will be delivered to a processor and where it will be processed. Production caps or penalties may be imposed on certain wells that cannot meet the capture goals. It is possible that other states in which QEP operates will require gas capture plans in the future to reduce flaring.

Additionally, in November 2016, BLM finalized the 2016 Waste Prevention Rule, which further regulates the venting, flaring and emission of natural gas on BLM and tribal leases. The 2016 Waste Prevention Rule took effect in January 2017. In September 2018, the BLM finalized the Revised Waste Prevention Rule, a rule that revised and replaced the 2016 Waste Prevention Rule, effective November 2018. The Revised Waste Prevention Rule rescinds certain provisions of the 2016 Waste Prevention Rule, revises other provisions of the 2016 Waste Prevention Rule, and adds provisions deeming gas vented or flared in accordance with applicable state or tribal requirements to be royalty free. ENGOs and certain states have challenged the Revised Waste Prevention Rule in the U.S. District Court for the Northern District of California, and industry groups have intervened in that action. Gas capture requirements, including any similar future obligations in North Dakota or our other locations, increase our operational costs and may restrict our production, which could materially and adversely affect our financial condition, results of operations and cash flows.

Rules regarding crude oil shipments by rail may pose unique hazards that may have an adverse effect on our operations. The NDI Commission requires that crude oil produced in the Bakken Petroleum System be conditioned to remove lighter, volatile hydrocarbons and improve the marketability and safe transportation of the crude oil by rail. The U.S. Department of Transportation rule regarding the safe transportation of flammable liquids by rail imposes certain requirements on "offerors" of crude oil, including sampling, testing, and certification requirements. These conditioning requirements, and any similar future obligations imposed at the state or federal level, may increase our operational costs or restrict our production, which could materially and adversely affect our financial condition, results of operations and cash flows.

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 species and 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 threatened and endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species as threatened or endangered in areas where we operate could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have a material adverse effect on our ability to develop and produce our reserves. Additionally, the U.S. Fish and Wildlife Service plans to issue a proposed rule listing the Lesser Prairie-Chicken as a threatened or endangered species. The Lesser Prairie-Chicken is a grouse species native to Texas, including parts of the Permian Basin where QEP operates.

Environmental laws are complex and potentially burdensome for QEP's operations. QEP must comply with numerous and complex federal, state and tribal environmental regulations governing activities on federal, state and tribal lands, notably including the federal Clean Air Act, Clean Water Act, SDWA, OPA, CERCLA, RCRA, NEPA, the Endangered Species Act, the National Historic Preservation Act and similar state laws and tribal codes. Federal, state and tribal regulatory agencies frequently impose conditions on the Company's activities under these laws. These restrictions have become more stringent over time and can limit or prevent exploration and production on significant portions of the Company's leasehold. These laws also allow certain ENGOs to oppose drilling on some of QEP's federal and state leases. These organizations sometimes sue federal and state regulatory agencies and/or the Company under these laws alleging procedural violations in an attempt to stop, limit or delay oil and gas development on public and other lands.

QEP may not be able to obtain the permits and approvals necessary to continue and expand its operations. Regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. It may be costly and time consuming to comply with requirements imposed by these authorities, and compliance may result in delays in the commencement or continuation of the Company's exploration and production. Further, the public may comment on and otherwise seek to influence the permitting process, including through intervention in the courts. Accordingly, necessary permits may not be issued, or if issued, may not be issued in a timely fashion, or may involve requirements that restrict QEP's ability to conduct its operations or to do so profitably. In addition, the BIA implemented final regulations in March 2016, which significantly altered the procedure for obtaining rights-of-way on tribal lands. These new regulations may increase the time and cost required to obtain necessary rights-of-way for QEP's operations on tribal lands, and rights-of-way issued under these new regulations expressly make QEP subject to a tribe's regulatory and judicial jurisdiction.

Our operations on the Fort Berthold Indian Reservation of the Three Affiliated Tribes in North Dakota are subject to various federal, state, local and tribal regulations and laws, any of which may increase our costs and have an adverse impact on our ability to effectively conduct our operations. Various federal agencies within the U.S. Department of the Interior, particularly the BIA and the Office of Natural Resource Revenue, along with the Three Affiliated Tribes of the Fort Berthold Indian Reservation (TAT), promulgate and enforce regulations pertaining to operations on the Fort Berthold Indian Reservation. In addition, the TAT is a sovereign nation having the right to enforce laws and regulations independent from federal, state and local statutes and regulations. These tribal laws and regulations include various taxes, fees, approvals and other conditions that apply to lessees, operators and contractors conducting operations on the Fort Berthold Indian Reservation. In addition, the consent or approval of the TAT will be necessary on an ongoing basis for the issuance of drilling permits and pooling/utilization clearance, and a delay in receiving any of such items could adversely affect our operations. Lessees and operators conducting operations on tribal lands are generally subject to the TAT's court system. One or more of these factors may increase our costs of doing business on the Fort Berthold Indian Reservation and may have an adverse impact on our ability to effectively transport products within the Fort Berthold Indian Reservation or to conduct our operations on such lands.

Federal and state hydraulic fracturing legislation or regulatory initiatives could increase QEP's costs and restrict its access to oil and gas reserves. Currently, well construction activities, including hydraulic fracture stimulation, are regulated by state agencies that review and approve oil and gas well design and operation. The EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the SDWA and issued guidance related to this asserted regulatory authority. The EPA may consider seeking to further regulate hydraulic fracturing fluids and/or the components of those fluids. At the state level, some states have adopted and other states have considered adopting regulations and moratoria that could restrict or prohibit hydraulic fracturing in certain circumstances. If new or more stringent federal, state, tribal or local regulations, restrictions or moratoria are adopted in areas where QEP operates, QEP could incur potentially 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 or stimulating wells in some areas.

In December 2016, the EPA released its final report on the potential for impacts to drinking water resources from hydraulic fracturing. The study concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances. Many other recent studies and reports have examined the potential impacts of hydraulic fracturing on the public and the environment. These and future studies could form a basis for additional regulations, which could lead to operational burdens similar to those described above.

QEP's ability to produce oil and gas economically and in commercial quantities could be impaired if it is unable to acquire adequate supplies of water for its drilling and completion operations or is unable to dispose of or recycle the water or other waste at a reasonable cost and in accordance with applicable environmental rules. The hydraulic fracture stimulation process on which QEP depends to produce commercial quantities of oil and gas requires the use and disposal of significant quantities of water. The availability of disposal wells with sufficient capacity to receive all of the water produced from QEP's wells may affect QEP's production. In some cases, QEP may need to obtain water from new sources and transport it to drilling sites, resulting in increased costs. QEP's inability to secure sufficient amounts of water, or to dispose of or recycle the water used in its operations, could adversely impact its operations. Moreover, the imposition of new environmental regulations could include restrictions on QEP's ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of gas. Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase QEP's operating costs or may cause QEP to delay, curtail or discontinue its exploration and development plans, which could have a material adverse effect on its business, financial condition, results of operations and cash flows.

Legislation or regulatory initiatives intended to address induced seismicity could restrict QEP's drilling and production activities as well as QEP's ability to dispose of produced water gathered from such activities, which could have a material adverse effect on QEP's business. State and federal regulatory agencies have focused on a possible connection between the disposal of wastewater in underground injection wells, or to a lesser extent the hydraulic fracturing of oil and gas wells, and the increased occurrence of seismic activity in certain areas, and regulatory agencies at all levels are continuing to study the possible linkage between oil and natural gas activity and induced seismicity. For example, in 2015, the United States Geological Survey identified eight states, including Texas, with areas of increased rates of seismic activity that may be attributable to fluid injection or oil and natural gas extraction activities. In addition, a number of lawsuits have been filed, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, in October 2014, the TRRC published a new rule governing permitting or re-permitting of disposal wells that requires, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or applicant fails to demonstrate that the produced water or other fluids are confined to the disposal zone or if scientific data indicate the well is likely or determined to be contributing to seismic activity, then the agency may deny, modify, suspend or terminate the permit application or existing operating permit for that well.

QEP operates injection wells and utilizes injection wells owned by third parties to dispose of large volumes of waste water associated with its drilling, completion and production operations. QEP disposes of these volumes of produced water pursuant to permits issued to QEP by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements or prohibitions on operating certain facilities, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations or the issuance of any orders or imposition of any requirements that restrict QEP's ability to use hydraulic fracturing or dispose of produced water gathered from its drilling and production activities by limiting volumes, injection pressures or rates, or restricting producing or disposal well locations, or requiring QEP to shut down disposal wells, could have a material adverse effect on QEP's business, financial condition and results of operations.

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Climate change and climate change legislation and regulatory initiatives including renewable energy mandates could result in increased operating costs and decreased demand for the oil and natural gas that we produce. Climate change, the costs that may be associated with its effects, the required use of renewable energy, and the regulation of GHG emissions have the potential to affect our business in many ways, including increasing the costs to provide our products, reducing the demand for and consumption of our products (due to changes in both costs and weather patterns) and negatively impacting the economic health of the regions in which we operate, all of which can create financial risks. In addition, if restrictions on GHG emissions and mandates for use of renewable energy significantly increase our costs to produce oil and gas, or significantly decrease demand for our products, the value of our oil and gas reserves may decrease. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital. In addition, legislative and regulatory responses related to GHG emissions, climate change and renewable energy use may result in increased operating costs, delays in obtaining air emissions and other necessary permits for new or modified facilities and reduced demand for the oil, gas and NGL that QEP produces. Federal and state courts and administrative agencies are considering the scope and scale of potential climate-change-related regulation under various existing laws pertaining to the environment, energy use and energy resource development. Federal, state and local governments may also pass laws specifically aimed at GHG regulation, and mandating the use of renewable energy sources, such as wind power and solar energy, or restricting or banning the use of gasoline or diesel powered vehicles, which may reduce demand for oil and natural gas. Although Congress previously considered but did not adopt proposed legislation aimed at reducing GHG emissions, recent Congressional resolutions and the new Democrat majority in the House of Representatives make it likely Congress will soon consider new legislation requiring decarbonization or use of renewable energy in much higher proportions. Further, state and local governments may pursue additional litigation against oil and gas producers for damages allegedly resulting from climate change. QEP's ability to access and develop new oil and gas reserves may also be restricted by climate change regulations, including GHG reporting and regulation.

The EPA has adopted final regulations under the Clean Air Act for the measurement and reporting of GHG emitted from certain large facilities and, as discussed above, has adopted additional regulations at 40 C.F.R Part 60, Subparts OOOO and OOOOa, to include additional requirements to reduce methane and volatile organic compound emissions from oil and natural gas facilities. The status of Subpart OOOOa is uncertain given the ongoing litigation, administrative reconsideration, proposed revisions to those rules announced in September 2018, and the prospects for legal challenges to such revisions. Additionally, in June 2014, the United States Supreme Court upheld a portion of EPA's GHG stationary source permitting program in Utility Air Regulatory Group v. EPA, but also invalidated a portion of it. The Court's holding does not prevent states from considering and adopting state-only major source permitting requirements based solely on GHG emission levels. Federal and state regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with air permits or other requirements of the Clean Air Act and associated state laws and regulations to which QEP's operations are subject, including certain existing GHG permitting requirements.

In December 2015, over 190 countries, including the U.S., met in Paris (COP 21) and agreed to reduce global emissions of GHG (Paris Agreement). The Paris Agreement provides for the cutting of carbon emissions every five years, beginning in 2023, and sets a goal of keeping global warming to a maximum limit of two degrees Celsius and a target limit of 1.5 degrees Celsius greater than pre-industrial levels. However, in June 2017, President Trump announced that the U.S. would initiate the formal process to withdraw from the Paris Agreement. Withdrawal will take a few years to implement due to the Paris Agreement's legal structure and language. The current state of development of ongoing international climate initiatives and any related domestic actions make it difficult to assess the timing or effect on our operations or to predict with certainty the future costs that we may incur in order to comply with future international treaties or domestic regulations. Following the initiation of the U.S. withdrawal from the Paris Agreement, state and local climate regulatory efforts are expected to increase. In several of the states in which QEP operates the regulatory authorities are considering various GHG registration and reduction programs, including methane leak detection monitoring and repair requirements specific to oil and gas facilities. In addition, the failure of the federal government to address climate change concerns, including, for example, a protracted delay by President Trump's administration in determining its own carbon-cost estimate (i.e., the estimate of how much carbon pollution costs society via climate damages) after rejecting the $40 per ton of carbon dioxide equivalent estimate of the Obama administration, could afford ENGOs additional opportunities to pursue further legal challenges to oil and gas drilling and pipeline projects.

Moreover, some experts believe climate change poses potential physical risks, including an increase in sea level and changes in weather conditions, such as an increase in precipitation and extreme weather events. In addition, warmer winters in some regions as a result of climate change could also decrease demand for natural gas. To the extent that such unfavorable weather conditions are realized due to climate change or otherwise, our operations may be adversely affected to a greater degree than we have previously experienced, including increased delays and costs. However, the uncertain nature of changes in extreme weather events (such as increased frequency, duration, and severity) and the long period of time over which any changes would take place make any estimations of future financial risk to our operations caused by these potential physical risks of climate change unreliable.

The taxation of independent producers is subject to change, and changes in tax law could increase our cost of doing business. We are subject to taxation by various taxing authorities at the federal, tribal, state and local levels where we do business. Legislation has been proposed in the past, and could be proposed and enacted in the future, that could increase the taxes or fees imposed on oil and natural gas extraction. Any such legislation could also result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our oil and natural gas.

If we were to experience an "ownership change," we could be limited in our ability to use certain tax attributes arising prior to the ownership change to offset future taxable income. If we were to experience an "ownership change," as determined under section 382 of the Internal Revenue Code of 1986, as amended, our ability to offset taxable income arising after the ownership change by utilizing NOLs arising prior to the ownership change could be limited, possibly substantially. Additionally, the deductibility of any pre-ownership change disallowed interest expense carryforward amount pursuant to the Tax Cuts and Jobs Act enacted in December 2017 (Tax Legislation) limitation of the deductibility of net business interest expense, could also be limited post-ownership change. An ownership change would establish an annual limitation on the amount of our pre-ownership change losses, including NOLs, tax credits, and disallowed interest expense carryforward, that we could utilize in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate.

QEP relies on highly skilled personnel and, if QEP is unable to retain or motivate key personnel, hire qualified personnel, or transfer knowledge from retiring personnel, QEP's operations may be negatively impacted. QEP's performance largely depends on the talents and efforts of highly skilled individuals. QEP's future success depends on its continuing ability to identify, hire, develop, motivate, and retain highly skilled personnel for all areas of its organization. Competition in the oil and gas industry for qualified employees is intense. QEP's continued ability to compete effectively depends on its ability to attract new employees and to retain and motivate its existing employees. QEP does not maintain key-man insurance for its key management personnel. In connection with the 2018 announcement of its plans to divest its assets in the Williston Basin, the Uinta Basin and Haynesville/Cotton Valley, QEP entered into retention and severance agreements with its executives and other key management personnel. Nonetheless, the departure in January 2019 of QEP's President and Chief Executive Officer and its Executive Vice President of operations, each of whom had a long tenure with the Company, and the loss of services of one or more of QEP's key management personnel could have a negative impact on QEP's operations and financial condition.

The Company's pension plans are currently underfunded and may require large contributions, which may divert funds from other uses. QEP has a closed, qualified, defined-benefit pension plan (Pension Plan), which covers 20 active and suspended participants, or 4%, of QEP's active employees and 194 participants who are retired or were terminated and vested. Effective January 1, 2016, the Pension Plan was frozen, such that employees do not earn additional defined benefits for future services. QEP also sponsors an unfunded, nonqualified Supplemental Executive Retirement Plan (SERP). Over time, periods of declines in interest rates and pension asset values may result in a reduction in the funded status of the Company's pension plans. As of December 31, 2018 and 2017, it is estimated that QEP's pension plans were underfunded by $28.8 million and $29.5 million, respectively. The underfunded status of QEP's pension plans may require that the Company make large contributions to such plans. QEP made cash contributions of $5.7 million and $6.0 million during the years ended December 31, 2018 and 2017, respectively, to the Pension Plan and SERP and expects to make contributions of approximately $5.5 million to these pension plans in 2019. QEP cannot, however, predict whether changing economic conditions, the future performance of assets in the plans or other factors will require the Company to make contributions in excess of its current expectations, diverting funds QEP would otherwise apply to other uses.

QEP is exposed to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption and/or financial loss. The oil and gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, and processing activities. For example, QEP depends on digital technologies to interpret seismic data; manage drilling rigs, production equipment and gathering systems; conduct reservoir modeling and reserves estimation; and process and record financial and operating data. Pipelines, refineries, power stations and distribution points for both fuels and electricity are becoming more interconnected by computer systems. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. QEP's technologies, systems and networks, and those of its vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of its business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. QEP does not maintain specialized insurance for possible losses resulting from a cyberattack on its assets that may shut down all or part of QEP's business. QEP's systems for protecting against cyber security risks may not be sufficient.

While QEP has experienced cyberattacks, QEP is not aware of any material losses relating to cyberattacks; however, there is no assurance that QEP will not suffer such losses in the future. In addition, as cybersecurity threats continue to evolve, QEP may expend additional resources to continue to modify or enhance its protective measures or to investigate or remediate any cybersecurity vulnerabilities.

QEP's certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, even if an acquisition or merger may be in QEP shareholders' best interests. QEP's certificate of incorporation authorizes its Board of Directors to issue preferred stock without shareholder approval. If QEP's Board of Directors elects to issue preferred stock, it could be more difficult for a third party to acquire QEP. In addition, some provisions of QEP's certificate of incorporation and bylaws could make it more difficult for a third party to acquire control of QEP, even if the transaction would be beneficial to QEP shareholders, including:

- authorization for the issuance of "blank check" preferred stock that our board of directors could issue to increase the number of outstanding shares to discourage a takeover attempt;
- advance notice requirements for shareholder proposals and nominations for elections to the Board of Directors to be acted upon at meetings of shareholders; and
- the inability of QEP shareholders to call special meetings or act by written consent.

In addition, Delaware law imposes restrictions on mergers and other business combinations between QEP and any holder of 15% or more of QEP's outstanding common stock.

Any provision of our certificate of incorporation or bylaws or Delaware law that has the effect of delaying or deterring a change in control could limit the opportunity for our stockholders to receive a premium for their shares of our common stock and could also affect the price that some investors are willing to pay for our common stock.

There may be future dilution of QEP's common stock, which could adversely affect the market price of QEP's common stock. QEP is not restricted from issuing additional shares of its common stock. In the future, QEP may issue shares of its common stock to raise cash for future capital expenditures, acquisitions or for general corporate purposes. QEP may also acquire interests in other companies by using a combination of cash and its common stock or just its common stock. QEP may also issue securities convertible into, exchangeable for or that represent the right to receive its common stock. Lastly, QEP issues stock options, restricted share awards, restricted share units and performance share units to its employees and directors as part of their compensation. Any of these events will dilute QEP shareholders' ownership interest in QEP and may reduce QEP's earnings per share and have an adverse effect on the price of QEP's common stock. In addition, sales of a substantial amount of QEP's common stock in the public market, or the perception that these sales may occur, could reduce the market price of QEP's common stock.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

The Company is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business. Item 103 of the SEC's Regulation S-K requires disclosure of material pending legal proceedings, other than ordinary routine litigation incidental to the business, to which QEP or any of its subsidiaries is a party or of which any of their property is the subject. Item 103 also requires disclosure of certain environmental matters when a governmental authority is a party to the proceedings and the proceedings involve potential monetary sanctions that the Company reasonably believes could exceed $100,000. The first two matters below are disclosed pursuant to that second requirement.

EPA Request for Information – In July 2015, QEP received an information request from the EPA pursuant to Section 114(a) of the Clean Air Act. The information request sought facts and data about certain tank batteries in QEP's Williston Basin operations. QEP timely responded to the information request, and has been in discussions with the EPA regarding this matter. While no formal federal enforcement action has been commenced in connection with the tank batteries to date, QEP anticipates that resolution of this matter will likely result in monetary penalties and require QEP to incur additional capital expenditures to correct non-compliance issues.

Louisiana Department of Environmental Quality Notice of Potential Penalty - In July 2010, QEP received a Notice of Potential Penalty (NOPP) from the Louisiana Department of Environmental Quality (LDEQ) regarding the assumption of ownership and operatorship of a single facility in Louisiana prior to transferring the facility's air quality permit. In 2011, QEP completed an internal audit, which identified 424 facilities in Louisiana for which QEP both failed to submit a complete permit application and to receive approval from the department prior to construction, modification, or operation. QEP has corrected and disclosed all known instances of non-compliance to the LDEQ. The LDEQ assumed lead responsibility for enforcement of the NOPP and may require the Company to pay a monetary penalty.

The Mabee Ranch Royalty Partnership, LP, et al. v. QEP Energy Company – On October 2, 2017, the Mabee Ranch Royalty Partnership, LP, John W. Mabee and Joseph Guy Mabee, Jr., surface and mineral owners of acreage in the Permian Basin in Martin and Andrews County, Texas, filed a petition in the District Court of Martin County, Texas, asserting that the Company (1) trespassed on the surface of their land by continuing surface operations following the alleged termination of certain surface use agreements and (2) breached various lease agreements by failing to correctly pay royalties and by allegedly using lease property to benefit off-lease operations. The suit alleges various tort and breach of contract claims and seeks actual money damages in excess of $1,000,000, plus interest, exemplary damages, court costs, and attorneys' fees, and a declaratory judgment that portions of the oil and gas leases covering the properties are void and no longer in effect.

Refer to Note 10 – Commitments and Contingencies in Item 8 of Part II of this Annual Report on Form 10-K for more information regarding our legal proceedings.

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

QEP's common stock is listed and traded on the New York Stock Exchange (NYSE:QEP). As of January 31, 2019, QEP had 5,091 shareholders of record.

Stock Performance Graph

The following stock performance information is not deemed to be "soliciting material" or to be "filed" with the SEC or subject to Regulation 14A or 14C under the Securities Exchange Act of 1934 or to the liabilities of Section 18 of the Securities Exchange Act of 1934, and will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent QEP specifically incorporates it by reference into such a filing.

During 2018, QEP made changes to its peer group to remove Energen Corporation and RSP Permian, Inc. as each of these entities were acquired in 2018. In addition, Callon Petroleum Company, Centennial Resource Development, Inc. and Jagged Peak Energy, Inc. were added to QEP's peer group, which is comprised of U.S. companies with similar size and scope to QEP.

QEP's previous peer group, as defined, consisted of the following companies:

Carrizo Oil & Gas, Inc.	Parsley Energy, Inc.
Cimarex Energy Company	PDC Energy, Inc.
Diamondback Energy, Inc.	Range Resources Corporation
Energen Corporation	RSP Permian, Inc.
EP Energy Corporation	SM Energy Company
Laredo Petroleum, Inc.	Southwestern Energy Company
Newfield Exploration Company	Whiting Petroleum Corporation
Oasis Petroleum Inc.	WPX Energy, Inc.

After the change in peer companies, QEP's 2018 peer group consisted of the following companies:

Callon Petroleum Company	Oasis Petroleum Inc.
Carrizo Oil & Gas, Inc.	Parsley Energy, Inc.
Centennial Resource Development, Inc.	PDC Energy, Inc.
Cimarex Energy Company	Range Resources Corporation
Diamondback Energy, Inc.	SM Energy Company
EP Energy Corporation	Southwestern Energy Company
Jagged Peak Energy, Inc.	Whiting Petroleum Corporation
Laredo Petroleum, Inc.	WPX Energy, Inc.
Newfield Exploration Company	

The performance presentation shown below is being furnished as required by applicable rules of the SEC and was prepared using the following assumptions:

- A $100 investment was made in QEP's common stock, the S&P 500 Index and the Company's old and new peer groups as of December 31, 2013, and its relative performance is tracked through December 31, 2018;
- Investment in the Company's old and new peer groups was weighted based on the stock market capitalization of each individual company within the peer group at the beginning of each period for which a return is indicated; and

- Dividends, if any, were reinvested on the relevant payment dates. QEP suspended the payment of dividends in February 2016.

	2013	2014	2015	2016	2017	2018
QEP Resources, Inc.	$100.00	$66.15	$44.04	$60.51	$31.45	$18.50
S&P 500 Index – Total Returns	$100.00	$113.69	$115.26	$129.05	$157.22	$150.33
New Peer Group	$100.00	$68.57	$42.97	$66.21	$52.30	$31.23
Old Peer Group	$100.00	$69.99	$44.39	$68.47	$54.84	$38.12

Recent Sales of Unregistered Securities; Purchases of Equity Securities by QEP and Affiliated Purchasers

On February 28, 2018, QEP announced the authorization by its Board of Directors to repurchase up to $1.25 billion of the Company's outstanding shares of common stock (February 2018 $1.25 billion Repurchase Program). The timing and amount of any QEP share repurchases will be subject to available liquidity and market conditions. The share repurchase program does not obligate QEP to acquire any specific number of shares and may be discontinued at any time.

The following repurchases of QEP shares were made by QEP in association with vested restricted share awards withheld for taxes and pursuant to the Company's share repurchase authorization.

Period	Total shares purchased [(1)]	Weighted-average price paid per share	Total shares purchased as part of publicly announced plans or programs	Maximum value that may yet be purchased under the plans or programs
				(in millions)
October 1, 2018 - October 31, 2018	52,639	$ 9.79	—	1,191.6
November 1, 2018 - November 30, 2018	43,824	$ 9.08	—	1,191.6
December 1, 2018 - December 31, 2018	—	$ —	—	1,191.6
Total	96,463		—	

(1) During the three months ended December 31, 2018, QEP purchased 96,463 shares from employees in connection with the settlement of income tax and related benefit withholding obligations arising from the vesting of restricted share grants.

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ITEM 6. SELECTED FINANCIAL DATA

Selected financial data for the five years ended December 31, 2018, is provided in the table below. Our financial results for the years ended December 31, 2016, 2015, and 2014 have been recast, in accordance with GAAP, to reflect the adoption of ASU No. 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the presentation of net periodic pension cost and net periodic postretirement benefit cost (see footnote (4) to the table below). In addition, our financial results for the year ended December 31, 2014 have been recast, in accordance with GAAP, to reflect the impact of the sale of substantially all of QEP's midstream business (see footnote (5) to the table below). Refer to Items 7 and 8 in Part II of this Annual Report on Form 10-K for further discussion of the factors affecting the comparability of the Company's financial data.

	Year Ended December 31,				
	2018[(1)]	2017[(1)]	2016[(1)]	2015	2014
Statement of Operations Data	(in millions, except per share amounts)				
Revenues[(2)(3)]	$1,932.6	$1,622.9	$1,377.1	$2,018.6	$3,293.2
Operating income (loss)[(4)]	$(1,260.4)	$101.5	$(1,600.7)	$(364.5)	$(840.3)
Income (loss) from continuing operations	$(1,011.6)	$269.3	$(1,245.0)	$(149.4)	$(409.5)
Net income from discontinued operations, net of income tax[(5)]	$—	$—	$—	$—	$1,193.9
Net income (loss)[(6)]	$(1,011.6)	$269.3	$(1,245.0)	$(149.4)	$784.4
Earnings (loss) per common share					
Basic from continuing operations[(6)]	$(4.25)	$1.12	$(5.62)	$(0.85)	$(2.28)
Basic from discontinued operations[(5)]	—	—	—	—	6.64
Basic total	$(4.25)	$1.12	$(5.62)	$(0.85)	$4.36
Diluted from continuing operations[(6)]	$(4.25)	$1.12	$(5.62)	$(0.85)	$(2.28)
Diluted from discontinued operations[(5)]	—	—	—	—	6.64
Diluted total	$(4.25)	$1.12	$(5.62)	$(0.85)	$4.36
Weighted-average common shares outstanding					
Used in basic calculation	237.9	240.6	221.7	176.6	179.8
Used in diluted calculation	237.9	240.6	221.7	176.6	179.8
Dividends per common share	$—	$—	$—	$0.08	$0.08
Balance Sheet Data					
Total Assets at December 31,	$6,117.8	$7,394.8	$7,245.4	$8,398.2	$9,256.4
Capitalization at December 31,					
Long-term debt	$2,507.1	$2,160.8	$2,020.9	$2,191.5	$2,187.7
Total equity	2,750.9	3,797.9	3,502.7	3,947.9	4,075.3
Total Capitalization	$5,258.0	$5,958.7	$5,523.6	$6,139.4	$6,263.0
Statement of Cash Flows Data					
Net cash provided by (used in) operating activities[(7)]	$816.2	$600.2	$667.2	$498.5	$1,492.2
Capital expenditures	$(1,299.7)	$(1,974.8)	$(1,208.1)	$(1,239.4)	$(2,726.4)
Net cash provided by (used in) investing activities	$(1,056.1)	$(1,168.0)	$(1,179.1)	$(1,217.6)	$578.2
Net cash provided by (used in) financing activities	$244.6	$125.8	$583.1	$(47.7)	$(990.6)
Non-GAAP Measure					
Adjusted EBITDA[(4)(8)]	$974.8	$736.1	$628.1	$1,031.2	$1,589.7

(1) The results are impacted by various acquisitions and divestitures. Refer to Note 3 – Acquisitions and Divestitures in Item 8 of Part II of this Annual Report on Form 10-K for more information on these transactions.

(2) Effective January 1, 2016, QEP terminated its contracts for resale and marketing transactions between its wholly owned subsidiaries, QEP Marketing and QEP Energy. In addition, substantially all of QEP Marketing's third-party purchase and sale agreements and gathering, processing and transportation contracts were assigned to QEP Energy, except those contracts related to natural gas storage activities and Haynesville Gathering. As a result, QEP has substantially reduced its marketing activities, and subsequently, is reporting lower resale revenue and expenses than it had in prior periods.

(3) In the first quarter of 2018, QEP adopted ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606), using the modified retrospective approach. During the year ended December 31, 2018, the revenues are impacted by the adoption of this ASU. Refer to Note 2 – Revenue in Item 8 of Part II of this Annual Report on Form 10-K for more information.

(4) In the first quarter of 2017, QEP early adopted ASU No. 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the presentation of net periodic pension cost and net periodic postretirement benefit cost, which is effective retrospectively. As a result, the Company has recast operating income and Adjusted EBITDA for the years ended December 31, 2016, 2015 and 2014. The Company recognizes service costs related to SERP and Medical Plan benefits within "General and administrative" expense on the Consolidated Statements of Operations and all other expenses related to the Pension Plan, SERP and Medical Plan are recognized within "Interest and other income (expense)" on the Consolidated Statements of Operations. Refer to Note 12 – Employee Benefits in Item 8 of Part II of this Annual Report on Form 10-K for more information.

(5) In December 2014, QEP sold substantially all of QEP's midstream business. The results of operations of QEP's midstream business (excluding results of Haynesville Gathering) have been reflected as discontinued operations and results for the year ended December 31, 2014, have been reclassified.

(6) Net income for 2017 was positively impacted by a $307.9 million tax benefit, primarily due to a revaluation of our net deferred tax liability to reflect the federal rate change resulting from 35% to 21% under the new Tax Legislation.

(7) In the first quarter of 2018, QEP adopted ASU No. 2016-18, Statement of Cash Flows (Topic 230): Restricted cash, which is effective retrospectively. As a result, the Company has recast net cash provided by (used in) operating activities for the years ended December 31, 2017, 2016, 2015 and 2014. Refer to Note 1 – Summary of Significant Accounting Policies in Item 8 of Part II of this Annual Report on Form 10-K for more information.

(8) Adjusted EBITDA is a non-GAAP financial measure. Management defines Adjusted EBITDA as earnings before interest, income taxes, depreciation, depletion and amortization (EBITDA), adjusted to exclude changes in fair value of derivative contracts, exploration expenses, gains and losses from asset sales, impairment, loss from early extinguishment of debt and certain other items. See Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, in this Annual Report on Form 10-K for additional disclosures related to Adjusted EBITDA.

The following table reconciles QEP's Net Income (Loss) (a GAAP measure) to Adjusted EBITDA. This non-GAAP measure should be considered by the reader in addition to, but not instead of, the financial statements prepared in accordance with GAAP.

	Year Ended December 31,				
	2018	2017	2016	2015	2014
	(in millions)				
Net income (loss)	$(1,011.6)	$269.3	$(1,245.0)	$(149.4)	$784.4
Net income from discontinued operations, net of tax	—	—	—	—	(1,193.9)
Net income (loss) from continuing operations	(1,011.6)	269.3	(1,245.0)	(149.4)	(409.5)
Interest expense	149.4	137.8	143.2	145.6	169.1
Interest and other (income) expense[1]	9.6	(1.6)	(23.7)	10.1	(5.8)
Income tax provision (benefit)	(317.4)	(312.2)	(708.2)	(93.6)	(232.5)
Depreciation, depletion and amortization	857.1	754.5	871.1	881.1	994.7
Unrealized (gains) losses on derivative contracts	(248.5)	(40.0)	367.0	183.7	(374.4)
Exploration expenses	0.3	22.0	1.7	2.7	9.9
Net (gain) loss from asset sales, inclusive of restructuring costs	(25.0)	(213.5)	(5.0)	(4.6)	148.6
Impairment	1,560.9	78.9	1,194.3	55.6	1,143.2
Loss from early extinguishment of debt	—	32.7	—	—	2.0
Other[1][2]	—	8.2	32.7	—	—
Adjusted EBITDA from continuing operations	974.8	736.1	628.1	1,031.2	1,445.3
Adjusted EBITDA from discontinued operations	—	—	—	—	144.4
Adjusted EBITDA	$974.8	$736.1	$628.1	$1,031.2	$1,589.7

(1) In the first quarter of 2017, QEP early adopted ASU No. 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the presentation of net periodic pension cost and net periodic postretirement benefit cost, which is effective retrospectively. As a result, the Company recast "Interest and other (income) expense" and "Other" for the years ended December 31, 2016, 2015 and 2014. The Company recognizes service costs related to SERP and Medical Plan benefits within "General and administrative" expense on the Consolidated Statements of Operations and all other expenses related to the Pension Plan, SERP and Medical Plan benefits are recognized within "Interest and other income (expense)" on the Consolidated Statements of Operations. Refer to Note 12 – Employee Benefits in Item 8 of Part II of this Annual Report on Form 10-K for more information.

(2) Reflects legal expenses and loss contingencies incurred during the years ended December 31, 2017 and 2016. The Company believes that these amounts do not reflect expected future operating performance or provide meaningful comparisons to past operating performance and therefore has excluded these amounts from the calculation of Adjusted EBITDA.

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

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide the reader of the financial statements with a narrative from the perspective of management on the financial condition, results of operations, liquidity and certain other factors that may affect the Company's operating results. MD&A should be read in conjunction with the Consolidated Financial Statements and related Notes included in Item 8 of Part II of this Annual Report on Form 10-K and also with "Risk Factors" in Item 1A of this report.

The following information updates the discussion of QEP's financial condition provided in its 2017 Annual Report on Form 10-K filing, and analyzes the changes in the results of operations between the years ended December 31, 2018 and 2017, and between the years ended December 31, 2017 and 2016.

OVERVIEW

QEP is an independent crude oil and natural gas exploration and production company with operations in two regions of the United States: the Southern Region (primarily in Texas) and the Northern Region (primarily in North Dakota). During 2018, the Company sold its Uinta Basin assets and entered into purchase and sale agreements to divest substantially all of its Haynesville/Cotton Valley assets in Louisiana and its Williston Basin assets in North Dakota. In January 2019, the Company closed the sale of its Haynesville/Cotton Valley assets. In February 2019, the Company announced the termination of the purchase and sale agreement related to its Williston Basin assets. Unless otherwise specified or the context otherwise requires, all references to "QEP" or the "Company" are to QEP Resources, Inc. and its subsidiaries on a consolidated basis. QEP's corporate headquarters are located in Denver, Colorado and shares of QEP's common stock trade on the New York Stock Exchange (NYSE) under the ticker symbol "QEP".

In February 2018, QEP's Board of Directors unanimously approved certain strategic and financial initiatives (2018 Strategic Initiatives), including plans to market its assets in the Williston Basin, Uinta Basin and Haynesville/Cotton Valley and focus its activities in the Permian Basin. The Company sold its Uinta Basin assets in September 2018 (Uinta Basin Divestiture) and closed the sale of the Haynesville/Cotton Valley assets in January 2019 (Haynesville Divestiture). In addition, the Company entered into a purchase and sale agreement for its Williston Basin assets in November 2018. In February 2019, the Company agreed with the buyer to terminate the purchase and sale agreement for its assets in the Williston Basin. Following the termination of the Planned Williston Basin Divestiture, QEP will continue to operate and develop its assets in the Williston Basin, including the Company's South Antelope and Fort Berthold leaseholds. See the Divestiture section below for additional discussion on the 2018 divestitures.

In February 2019, QEP's Board of Directors commenced a comprehensive review of strategic alternatives to maximize shareholder value, which could result in a merger or sale of the Company or other transaction involving the Company's assets. QEP intends to engage in discussions with a variety of parties that have expressed interest in a potential transaction. Additionally, in light of the reduction of the Company's operational footprint over the last twelve months, QEP has reassessed its organizational needs and intends to significantly reduce its general and administrative expense (excluding $61.0 million of expenses associated with our 2018 Strategic Initiatives) by approximately 45% to ensure its cost structure is competitive with industry peers. The Company expects that the majority of the organizational changes will be implemented during the first half of 2019.

As a part of the strategic initiatives, QEP has incurred or expects to incur costs associated with contractual termination benefits, including severance, accelerated vesting of share-based compensation and other expenses. Refer to Note 3 – Acquisitions and Divestitures, Note 8 – Restructuring Costs and Note 16 – Subsequent Events in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Acquisitions and Divestitures

While we believe our extensive inventory of identified drilling locations provides a solid base for growth in production and reserves, we will continue to evaluate and acquire properties in our operating areas to add additional development opportunities and facilitate the drilling of long lateral wells.

Acquisitions

During the year ended December 31, 2018, QEP closed $49.1 million of acquisitions from various entities that owned additional oil and gas interests in certain properties included in the 2017 Permian Basin Acquisition on substantially the same terms and conditions as the 2017 Permian Basin Acquisition. In addition, QEP acquired various oil and gas properties, which primarily included proved and unproved leasehold acreage in the Permian Basin for an aggregate purchase price of $16.5 million, subject to post-closing purchase price adjustments.

In the fourth quarter of 2017, QEP acquired additional oil and gas properties in the Permian Basin for an aggregate purchase price of $721.0 million (2017 Permian Basin Acquisition). The 2017 Permian Basin Acquisition consists of approximately 15,100 acres, mainly in Martin County, Texas, which are held by production from vertical wells. QEP structured the transaction as a like-kind exchange under Section 1031 of the Internal Revenue Service Code and funded the purchase price with the proceeds from the sale of QEP's Pinedale assets. In addition to the 2017 Permian Basin Acquisition, QEP acquired various oil and gas properties, which primarily included proved and unproved leasehold acreage and additional surface acreage in the Permian Basin, for an aggregate purchase price of $94.5 million. In conjunction with these acquisitions, the Company recorded $5.3 million of goodwill, which was subsequently impaired in 2017.

In October 2016, QEP acquired oil and gas properties in the Permian Basin for an aggregate purchase price of approximately $591.0 million (2016 Permian Basin Acquisition). The 2016 Permian Basin Acquisition consisted of approximately 9,600 net acres in Martin County, Texas, which are primarily held by production from existing vertical wells. The 2016 Permian Basin Acquisition was funded with cash on hand, which included proceeds from an equity offering in June 2016. In addition to the 2016 Permian Basin Acquisition, QEP acquired various oil and gas properties, primarily in the Permian and Williston basins, for an aggregate purchase price of $54.6 million, which included additional interests in QEP operated wells and additional undeveloped leasehold acreage.

Divestitures

In January 2019, QEP closed its previously announced Haynesville Divestiture for net cash proceeds of $605.1 million, subject to post-closing purchase price adjustments. In addition, $32.2 million was placed in escrow due to title defects asserted prior to closing, all or a portion of which QEP expects to receive pursuant to the purchase and sale agreement's title dispute resolution procedures. As of December 31, 2018, the Haynesville/Cotton Valley assets were classified in the Company's Consolidated Financial Statements as held for sale. Refer to Note 3 – Acquisitions and Divestitures in Item 8 of Part II of this Annual Report on Form 10-K for more information.

In November 2018, the Company's wholly owned subsidiary, QEP Energy Company, entered into a purchase and sale agreement for its assets in the Williston Basin for a purchase price of $1,725.0 million, subject to purchase price adjustments. The purchase price was comprised of $1,650.0 million in cash and contractual rights to receive $75.0 million of the buyer's common stock if certain conditions were met. The transaction was subject to certain conditions, including, but not limited to, approval of the buyer's shareholders and regulatory approvals. In February 2019, the Company agreed with the buyer to terminate the purchase and sale agreement for its assets in the Williston Basin. As of December 31, 2018, the Williston Basin assets were classified as held and used in the Company's Consolidated Financial Statements as the assets did not meet the held for sale criteria.

In September 2018, QEP sold its natural gas and oil producing properties, undeveloped acreage and related assets located in the Uinta Basin for net cash proceeds of $153.0 million, subject to post-closing purchase price adjustments. During the year ended December 31, 2018, QEP recorded a pre-tax loss of $12.6 million related to the Uinta Basin Divestiture, which included $5.4 million related to estimated restructuring costs recorded on the Consolidated

Statements of Operations within "Net gain (loss) from asset sales, inclusive of restructuring costs". In conjunction with the Uinta Basin Divestiture, QEP recorded $402.8 million of proved and unproved properties impairment during the year ended December 31, 2018. Refer to Note 1 – Summary of Significant Accounting Policies, Note 3 – Acquisitions and Divestitures and Note 8 – Restructuring Costs in Item 8 of Part II of this Annual Report on Form 10-K for more information.

In addition to the Uinta Basin Divestiture, during the year ended December 31, 2018, QEP received net cash proceeds of $90.6 million and recorded a net pre-tax gain on sale of $38.5 million related to the divestiture of properties outside our main operating areas.

As a part of the strategic initiatives and the associated divestitures, QEP has incurred or expects to incur costs associated with contractual termination benefits, including severance, accelerated vesting of share-based compensation and other expenses. Refer to Note 8 – Restructuring Costs in Item 8 of Part II of this Annual Report on Form 10-K for more information.

In September 2017, QEP sold its assets in Pinedale (Pinedale Divestiture), for net cash proceeds (after purchase price adjustments) of $718.2 million. During the year ended December 31, 2018 and 2017, QEP recorded pre-tax gains on sale of $1.2 million and $180.4 million, respectively, which were recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations. In connection with the Pinedale Divestiture, QEP agreed to reimburse the buyer for certain deficiency charges it incurs related to gas processing and NGL transportation and fractionation contracts between the effective date of the sale and December 31, 2019, in an aggregate amount not to exceed $45.0 million. As of December 31, 2018, the remaining liability associated with estimated future payments for this commitment was $9.3 million.

In addition to the Pinedale Divestiture, during the year ended December 31, 2017, QEP received additional net cash proceeds of $88.6 million, primarily related to the sale of non-core properties in the Other Northern area.

In 2016, QEP sold its interest in certain non-core properties in the Other Southern area for aggregate proceeds of $29.0 million.

Financial and Operating Highlights

During the year ended December 31, 2018, QEP:

- Entered into a purchase and sale agreement to sell its assets in Haynesville/Cotton Valley in 2019 for an aggregate purchase price of approximately $735.0 million, subject to purchase price adjustments;
- Entered into a purchase and sale agreement to sell its assets in the Williston Basin in 2019 for a purchase price of $1,725.0 million, subject to purchase price adjustments;
- Received $243.6 million proceeds from disposition of assets in 2018, including the Uinta Basin and other non-core assets, which were used to pay down debt;
- Recognized a net realized oil price of $53.02 per bbl, a $4.80 per bbl increase compared to 2017;
- Delivered oil equivalent production of 51.9 MMboe;
- Delivered record oil and condensate production of 23.9 MMbbls, including a record 12.1 MMbbls in the Permian Basin;
- Reported year-end total proved reserves of 658.2 MMboe, including record proved crude oil and condensate reserves of 339.1 MMbbls, a 6% increase compared to 2017;
- Incurred capital expenditures (excluding property acquisitions) of $1,176.6 million, a 4% decrease over 2017;
- Repurchased and retired 6.2 million shares of the Company's outstanding common stock for $58.4 million;
- Generated a net loss of $1,011.6 million, or $4.25 per diluted share, primarily due to impairment expense of $1,560.9 million related to our Williston Basin and Uinta Basin assets; and
- Reported $974.8 million of Adjusted EBITDA (a non-GAAP measure defined and reconciled in Item 7 of Part II of this Annual Report on Form 10-K), a 32% increase over 2017.

Outlook

The Company continues to focus on reducing its operating costs and per well drilling costs and managing its liquidity. We believe our balance sheet and sufficient liquidity will allow us to grow oil and condensate production in our operating areas and achieve our strategic initiatives.

Based on current commodity prices, we expect to be able to fund our planned capital program for 2019 with cash flow from operating activities, cash on hand and borrowings under our credit facility. Our total capital expenditures (excluding property acquisitions), for 2019 are expected to be approximately $640.0 million, a decrease of approximately 46% from 2018 capital expenditures. We continuously evaluate our level of drilling and completion activity in light of drilling results, commodity prices and changes in our operating and development costs and will adjust our capital investment program based on such evaluations. See "Cash Flow from Investing Activities" for further discussion of our capital expenditures.

Factors Affecting Results of Operations

Our Strategic Initiatives
During 2018, we pursued our 2018 Strategic Initiatives to reposition QEP as a pure-play Permian Basin company. The Uinta Basin Divestiture and the Haynesville Divestiture have provided meaningful additional capital to the Company. The proceeds from divestitures were deployed in 2018 and early 2019 primarily to reduce debt. In February 2019, QEP agreed to terminate the purchase and sale agreement related to the Planned Williston Basin Divestiture. Organizational modifications due to these divestitures and our other strategic changes can alter risk and control environments; disrupt ongoing business; distract management and employees; increase expenses; result in additional liabilities, investigations and litigation; and impact corporate strategy – all of which could adversely affect our results of operations. For example, we have incurred and expect to incur significant general and administrative expense, including transaction costs, retention bonuses and severance payments, in connection with the strategic initiatives. QEP producing properties are located in the Permian and Williston basins. As a result of our lack of diversification in asset type and limited geographic diversification, any delays or interruptions of production caused by such factors as governmental regulation, transportation capacity constraints, curtailment of production or interruption of transportation, price fluctuations, natural disasters or shutdowns of the pipelines connecting our production to refineries would have a significantly greater impact on our results of operations than if we possessed more diverse assets and locations.
As a result of the termination of the purchase and sale agreement related to the Planned Williston Basin Divestiture, we will not realize the expected benefits of the proposed sale, and we have incurred transaction costs, including legal, accounting, financial advisory and other costs relating to the Planned Williston Basin Divestiture, a portion of which will not be reimbursed in accordance with the terms of the purchase and sale agreement. Since we are unable to successfully complete the Planned Williston Basin Divestiture, the price of our securities could be impacted.

Shareholder Activism
Elliott Management Corporation, is a beneficial holder of approximately 4.9% of our common stock (based on Elliott's Form 13F-HR filed on February 14, 2019). On January 7, 2019, Elliott made a proposal to our Board to acquire all shares of our common stock for $8.75 per share. Our Board is currently evaluating the proposal and has made a decision to engage in a process to explore strategic alternatives. Our business and/or operations could be adversely affected by these and any future actions of activist shareholders. Responding to actions by activist shareholders could be costly and time-consuming, disrupting our operations and diverting the attention of our management and employees. Activities of activist shareholders could interfere with our ability to execute our strategic plan or realize short- or long-term value from our assets and could interfere with our ability to pursue strategic alternatives to Elliott's proposal. Perceived uncertainties as to our future direction could also result in the loss of potential business opportunities, make it more difficult or costly to attract and retain qualified personnel and affect the trading price of our securities.

Supply, Demand, Market Risk and their Impact on Oil and Gas Prices
Oil and gas prices are affected by many factors outside of our control, including changes in supply and demand, which are impacted by weather conditions, pipeline capacity constraints, inventory storage levels, basis differentials, export capacity, strength of the U.S. dollar and other factors. In recent years, oil and gas prices have been affected by supply growth, particularly in the U.S., driven by advances in drilling and completion technologies, and fluctuations in demand driven by a variety of factors.

Changes in the market prices for oil, gas and NGL directly impact many aspects of QEP's business, including its financial condition, revenues, results of operations, planned drilling and completion activity and related capital expenditures, our proved undeveloped (PUD) reserves conversion rate, liquidity, rate of growth, costs of goods and services required to drill, complete and operate wells, and the carrying value of its oil and gas properties. Historically, field-level prices received for QEP's oil and gas production have been volatile. During the past five years, the posted price for WTI crude oil has ranged from a low of $26.19 per barrel in February 2016 to a high of $107.95 per barrel in June 2014. The Henry Hub spot market price of natural gas has ranged from a low of $1.49 per MMBtu in March 2016 to a high of $8.15 per MMBtu in February 2014. If prices of oil, gas or NGL decline to early 2016 levels or further, our operations, financial condition and level of expenditures for the development of our oil and gas reserves may be materially and adversely affected.

Global Geopolitical and Macroeconomic Factors
QEP continues to monitor the global economy, including Europe and China's economic outlook; OPEC countries' oil production and policies regarding production quotas; political unrest and global economic issues; slowing growth in certain emerging market economies; actions taken by the United States Congress and the president of the United States; the U.S. federal budget deficit; changes in regulatory oversight policy; commodity price volatility; tariffs on goods we use in our operations or on the products we sell; the impact of a potential increase in interest rates; volatility in various global currencies; and other factors. A dramatic decline in regional or global economic conditions, a major recession or depression, regional political instability, economic sanctions, war, or other factors beyond the control of QEP could have a significant impact on oil, gas and NGL supply, demand and prices and the Company's ability to continue its planned drilling programs and could materially impact the Company's financial position, results of operations and cash flow from operations. Disruption to the global oil supply system, political and/or economic instability, fluctuations in currency values, and/or other factors could trigger additional volatility in oil prices.

Due to continued global economic uncertainty and the corresponding volatility of commodity prices, QEP continues to focus on maintaining a sufficient liquidity position to ensure financial flexibility. QEP uses commodity derivatives to reduce the volatility of the prices QEP receives for a portion of its production and to partially protect cash flow and returns on invested capital from a drop in commodity prices. Generally, QEP intends to enter into commodity derivative contracts for approximately 50% to 75% of its forecasted annual production by the end of the first quarter of each fiscal year. At December 31, 2018, after taking the divestiture of the Haynesville/Cotton Valley assets into account, QEP forecasted its 2019 annual production to be approximately 29.0 MMboe and had approximately 86% of its forecasted oil and condensate production covered with fixed-price swaps and none of its forecasted gas production covered with fixed-price swaps after the novation of gas derivatives associated with the Haynesville Divestiture. See Item 7A – "Quantitative and Qualitative Disclosures about Market Risk – Commodity Price Risk Management", of Part II of this Annual Report on Form 10-K for further details concerning QEP's commodity derivatives transactions.

Potential for Future Asset Impairments
The carrying values of the Company's properties are sensitive to declines in oil, gas and NGL prices as well as increases in various development and operating costs and expenses and, therefore, are at risk of impairment. The Company uses a cash flow model to assess its proved properties for impairment. The cash flow model includes numerous assumptions, including estimates of future oil and condensate, gas and NGL production, estimates of future prices for production that are based on the price forecast that management uses to make investment decisions, including estimates of basis differentials, future operating costs, transportation expenses, production taxes, and development costs that management believes are consistent with its price forecast, and discount rates. Management also considers a number of other factors, including the forward curve for future oil and gas prices and developments in regional transportation infrastructure, when developing its estimate of future prices for production. All inputs for the cash flow model are evaluated at each date of estimate. An assessment of the sensitivity of our capitalized costs to changes in the assumptions in our cash flow calculations is not practicable, given the numerous assumptions (e.g., future oil, gas and NGL prices; production and reserves; pace and timing of development plans; timing of capital expenditures; operating costs; drilling and development costs; and inflation and discount rates) that can materially affect our estimates.

We base our fair value estimates on projected financial information that we believe to be reasonably likely to occur. The signing of a purchase and sale agreement could also cause the Company to recognize an impairment of proved properties. For assets subject to a purchase and sale agreement, the terms of the purchase and sale agreement are used as an indicator of fair value. If a range is estimated for the amount of possible future cash flows, the fair value of property is measured utilizing a probability-weighted approach whereas the likelihood of possible outcomes is taken into consideration. Specific to the Planned Williston Basin Divestiture, the Company obtained a Black-Scholes-Merton estimate of the value of the contractual rights to receive up to 5.8 million shares of the buyer's common stock at December 31, 2018. Unfavorable adjustments to some of the above listed assumptions would likely be offset by favorable adjustments in other assumptions. For example, the impact of sustained reduced oil, gas and NGL prices on future undiscounted cash flows would likely be offset by lower drilling and development costs and lower operating costs. In addition, the signing of a purchase and sale agreement could also cause the Company to recognize an impairment of proved properties. For assets subject to a purchase and sale agreement, the terms of the purchase and sale agreement are used as an indicator of fair value.

During the year ended December 31, 2018, the Company recorded impairments of $1,560.9 million primarily due to impairments of proved and unproved properties as a result of signing purchase and sale agreements for the Planned Williston Basin Divestiture and the Uinta Basin Divestiture. During the year ended December 31, 2017, impairments were $78.9 million primarily due to impairments of proved properties in the Other Northern area, an underground gas storage facility and unproved properties in the Permian Basin. During the year ended December 31, 2016, impairments were $1,194.3 million primarily due to impairments of proved properties in Pinedale. For more information see Item 1A – Risk Factors in Part I and Note 1 – Summary of Significant Accounting Policies, in Item 8 of Part II of this Annual Report on Form 10-K.

If forward oil prices decline from December 31, 2018 levels or we experience negative changes in estimated reserve quantities, we could have proved and unproved property at risk for impairment. The actual amount of impairment incurred, if any, for these properties will depend on a variety of factors including, but not limited to, subsequent forward price curve changes, the additional risk-adjusted value of probable and possible reserves associated with the properties, weighted-average cost of capital, operating cost estimates and future capital expenditure estimates.

Tax Legislation
The Tax Legislation enacted in December 2017 reduced our federal corporate tax rate from 35% to 21%. In addition, the Tax Legislation eliminated AMT and QEP has the ability to offset its regular tax liability or claim refunds for taxable years 2018 through 2021 for AMT credits carried forward from prior years. The Company currently anticipates it will realize approximately $148.4 million in AMT credit refunds over the next four years with $74.2 million to be realized in 2019 for tax year 2018, which is shown in "Income tax receivable" with the remaining $74.2 million included in "Deferred income taxes" on the Consolidated Balance Sheet as of December 31, 2018.

Multi-Well Pad Drilling and Completion
To reduce the costs of well location construction and rig mobilization and demobilization and to obtain other efficiencies, QEP utilizes multi-well pad drilling where practical. For example, in the Permian Basin QEP utilizes "tank-style" development, in which we simultaneously develop multiple subsurface targets by drilling and completing all wells in a given "tank" before any individual well is turned to production. We believe this approach maximizes the economic recovery of oil through the simultaneous development of multiple subsurface targets, while improving capital efficiency through shared surface facilities, which we believe will reduce per-unit operating costs and result in expanded operating margins and improve our returns on invested capital. In certain of our producing areas, wells drilled on a pad are not completed and brought into production until all wells on the pad are drilled and the drilling rig is moved from the location. As a result, multi-well pad drilling delays the completion of wells and the commencement of production. In addition, existing wells that offset new wells being completed by QEP or offset operators may need to be temporarily shut-in during the completion process. Such delays and well shut-ins have caused and may continue to cause volatility in QEP's quarterly operating results. In addition, delays in completion of wells may impact planned conversion of PUD reserves to proved developed reserves.

Uncertainties Related to Claims
QEP is currently subject to claims that could adversely impact QEP's liquidity, operating results and capital expenditures for a particular reporting period, including, but not limited to those described in Note 10 – Commitments and Contingencies, in Item 8 of Part II of this Annual Report on Form 10-K. Given the uncertainties involved in these matters, QEP is unable to predict the ultimate outcomes.

RESULTS OF OPERATIONS

Net Income

QEP generated a net loss during the year ended December 31, 2018, of $1,011.6 million, or $4.25 per diluted share, compared to net income of $269.3 million, or $1.12 per diluted share, in 2017. The increase in net loss for the year ended December 31, 2018, compared to the year ended December 31, 2017, was primarily due to an increase in impairment expense of $1,482.0 million, a $188.5 million decrease in net gain from asset sales, inclusive of restructuring costs and an increase in depreciation, depletion, and amortization expense of $102.6 million. These changes were partially offset by a $326.0 million increase in oil and condensate, gas, and NGL revenues (primarily oil and condensate revenue) and a decrease in transportation and processing costs of $127.7 million.

QEP generated net income during the year ended December 31, 2017, of $269.3 million, or $1.12 per diluted share, compared to a net loss of $1,245.0 million, or $5.62 per diluted share, in 2016. The increase in net income for the year ended December 31, 2017, compared to the year ended December 31, 2016, was primarily due to a decrease in impairment expense of $1,115.4 million, a $245.8 million (18%) increase in revenues (primarily oil and condensate revenue) and an increase of $257.5 million in realized and unrealized derivative gains. Net income during the year ended December 31, 2017 was also positively impacted by a $307.9 million tax benefit, primarily due to a revaluation of our net deferred tax liability to reflect the federal rate change resulting from 35% to 21% under the Tax Legislation.

Adjusted EBITDA (Non-GAAP)

Management defines Adjusted EBITDA (a non-GAAP measure) as earnings before interest, income taxes, depreciation, depletion and amortization (EBITDA), adjusted to exclude changes in fair value of derivative contracts, exploration expenses, gains and losses from asset sales, impairment, loss from early extinguishment of debt and certain other items. Management uses Adjusted EBITDA to evaluate QEP's financial performance and trends, make operating decisions and allocate resources. Management believes the measure is useful supplemental information for investors because it eliminates the impact of certain nonrecurring, non-cash and/or other items that management does not consider as indicative of QEP's performance from period to period. QEP's Adjusted EBITDA may be determined or calculated differently than similarly titled measures of other companies in our industry, which could reduce the usefulness of this non-GAAP financial measure when comparing our performance to that of other companies.

Below is a reconciliation of net income (loss) (a GAAP measure) to Adjusted EBITDA. This non-GAAP measure should be considered by the reader in addition to, but not instead of, the financial statements prepared in accordance with GAAP.

	Year Ended December 31,		
	2018	2017	2016
	(in millions)		
Net income (loss)	$(1,011.6)	$269.3	$(1,245.0)
Interest expense	149.4	137.8	143.2
Interest and other (income) expense[(1)]	9.6	(1.6)	(23.7)
Income tax provision (benefit)	(317.4)	(312.2)	(708.2)
Depreciation, depletion and amortization	857.1	754.5	871.1
Unrealized (gains) losses on derivative contracts	(248.5)	(40.0)	367.0
Exploration expenses	0.3	22.0	1.7
Net (gain) loss from asset sales, inclusive of restructuring costs	(25.0)	(213.5)	(5.0)
Impairment	1,560.9	78.9	1,194.3
Loss from early extinguishment of debt	—	32.7	—
Other[(1)(2)]	—	8.2	32.7
Adjusted EBITDA	$974.8	$736.1	$628.1

(1) In the first quarter of 2017, QEP early adopted ASU No. 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the presentation of net periodic pension cost and net periodic postretirement benefit cost, which is effective retrospectively. As a result, the Company recast "Interest and other (income) expense" and "Other" for the year ended December 31, 2016. The Company recognizes service costs related to SERP and Medical Plan benefits within "General and administrative" expense on the Consolidated Statements of Operations and all other expenses related to the Pension Plan, SERP and Medical Plan benefits are recognized within "Interest and other income (expense)" on the Consolidated Statements of Operations. Refer to Note 12 – Employee Benefits in Item 8 of Part II of this Annual Report on Form 10-K for more information.

(2)

Reflects legal expenses and loss contingencies incurred during the years ended December 31, 2017 and 2016. The Company believes that these amounts do not reflect expected future operating performance or provide meaningful comparisons to past operating performance and therefore has excluded these amounts from the calculation of Adjusted EBITDA.

Adjusted EBITDA increased to $974.8 million during the year ended December 31, 2018, compared to $736.1 million in 2017, primarily due to an 18% increase in average realized prices, a 30% decrease in adjusted transportation and processing costs (defined below) and an 11% decrease in lease operating expense. These changes were partially offset by an 85% decrease in gas production due to the Pinedale Divestiture in late 2017 and the Uinta Basin Divestiture in late 2018, a 44% increase in general and administrative expenses and a 14% increase in production and property taxes.

Adjusted EBITDA increased to $736.1 million during the year ended December 31, 2017, compared to $628.1 million in 2016, primarily due to a 15% increase in average realized prices, a 15% decrease in transportation and processing costs and a 22% decrease in general and administrative expenses. These changes were partially offset by a 5% decrease in oil equivalent production, a 31% increase in lease operating expense and a 21% increase in production and property taxes.

Revenue

The following table presents our revenues disaggregated by revenue source.

	Year Ended December 31,			Change	
	2018	2017[1]	2016[1]	2018 vs 2017	2017 vs 2016
	(in millions)				
Oil and condensate, gas and NGL sales, as presented	$1,871.3	$1,545.3	$1,269.7	$326.0	$275.6
Transportation and processing costs in revenue[2]	55.0	—	—	55.0	—
Oil and condensate, gas and NGL sales, as adjusted[3]	$1,926.3	$1,545.3	$1,269.7	$271.0	275.6
Oil and condensate sales	$1,422.4	$939.4	$769.1	$483.0	$170.3
Gas sales	393.0	494.0	417.1	(101.0)	76.9
NGL sales	110.9	111.9	83.5	(1.0)	28.4
Oil and condensate, gas and NGL sales, as adjusted[3]	$1,926.3	$1,545.3	$1,269.7	$381.0	275.6

(1) Prior period amounts have not been adjusted under the modified retrospective method for the new revenue recognition rule. Refer to Note 2 – Revenue in Item 8 of Part II of this Annual Report on Form 10-K for more information.

(2) Transportation and processing costs in the table above are not representative of total transportation and processing costs incurred for the year ended December 31, 2018. Refer to the Operating Expenses section below for a reconciliation of total transportation and processing costs.

(3) Above is a reconciliation of Oil and condensate, gas and NGL sales (a GAAP measure) as presented on the Consolidated Statements of Operations to Oil and condensate, gas and NGL sales, as adjusted (a non-GAAP measure). Oil and condensate, gas and NGL sales, as adjusted excludes transportation and processing costs that are included as part of "Oil and condensate, gas and NGL sales" on the Consolidated Statements of Operations. Management removes these costs from "Oil and condensate, gas and NGL sales" included on the Consolidated Statements of Operations to reflect total revenue associated with its production prior to deducting any expenses. Management believes that this non-GAAP measure is useful supplemental information for investors as it is reflective of the total revenue generated from its wells for the period. This non-GAAP measure should be considered by the reader in addition to but not instead of, the financial measure prepared in accordance with GAAP. Refer to Note 2 – Revenue in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Revenue, Volume and Price Variance Analysis

The following table shows volume and price related changes for each of QEP's adjusted production-related revenue categories for the year ended December 31, 2018 compared to the years ended December 31, 2017 and 2016:

	Oil and condensate	Gas	NGL	Total
Oil and condensate, gas and NGL sales, as adjusted	(in millions)			
Year ended December 31, 2016	$769.1	$417.1	$83.5	$1,269.7
Changes associated with volumes[1]	(25.5)	(18.4)	(8.5)	(52.4)
Changes associated with prices[2]	195.8	95.3	36.9	328.0
Year ended December 31, 2017	$939.4	$494.0	$111.9	$1,545.3
Changes associated with volumes[1]	206.4	(86.3)	(14.7)	105.4
Changes associated with prices[2]	276.6	(14.7)	13.7	275.6
Year ended December 31, 2018	$1,422.4	$393.0	$110.9	$1,926.3

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(1) The revenue variance attributed to the change in volume is calculated by multiplying the change in volumes from the years ended December 31, 2018 and 2017, as compared to the years ended December 31, 2017 and 2016, by the average field-level price for the years ended December 31, 2017 and 2016, respectively.

(2) The revenue variance attributed to the change in price is calculated by multiplying the change in field-level prices from the years ended December 31, 2018 and 2017, as compared to the years ended December 31, 2017 and 2016, by the respective volumes for the years ended December 31, 2018 and 2017, respectively. Pricing changes are driven by changes in commodity field-level prices, excluding the impact from commodity derivatives.

A comparison of net realized average oil, gas and NGL prices, including the realized gains and losses on commodity derivative contracts, is provided in the following table:

	Year Ended December 31,			Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
Oil (per bbl)					
Average field-level price	$59.43	$47.88	$37.90	$11.55	$9.98
Commodity derivative impact	(6.41)	0.34	4.25	(6.75)	(3.91)
Net realized price	$53.02	$48.22	$42.15	$4.80	$6.07
Gas (per Mcf)					
Average field-level price	$2.82	$2.92	$2.36	$(0.10)	$0.56
Commodity derivative impact	(0.04)	(0.13)	0.25	0.09	(0.38)
Net realized price	$2.78	$2.79	$2.61	$(0.01)	$0.18
NGL (per bbl)					
Average field-level price	$23.79	$20.85	$13.97	$2.94	$6.88
Commodity derivative impact	—	—	—	—	—
Net realized price	$23.79	$20.85	$13.97	$2.94	$6.88
Average net equivalent price (per Boe)					
Average field-level price	$37.15	$29.08	$22.76	$8.07	$6.32
Commodity derivative impact	(3.06)	(0.29)	2.35	(2.77)	(2.64)
Net realized price	$34.09	$28.79	$25.11	$5.30	$3.68

December 31, 2018 compared to December 31, 2017

Oil and condensate sales. Oil and condensate sales were $1,422.4 million for the year ended December 31, 2018, an increase of $483.0 million, or 51%, compared to 2017. This increase was a result of a 24% increase in average field-level prices and a 22% increase in oil and condensate production volumes. The increase in average field-level oil prices was driven by an increase in average NYMEX-WTI oil prices for the comparable period, partially offset by a $2.73 per bbl, or 94% increase, in the basis differential relative to the average NYMEX-WTI oil price in 2018 compared to 2017. The 22% increase in oil and condensate production volumes was primarily driven by an increase in production in the Permian Basin due to increased drilling and completion activity, partially offset by a decrease in production in the Williston Basin due to decreased drilling activity and a loss of volumes as a result of the Pinedale Divestiture in September 2017 and the Uinta Basin Divestiture in September 2018.

Gas sales. Gas sales were $393.0 million for the year ended December 31, 2018, a decrease of $101.0 million, or 20%, compared to 2017. This decrease was a result of a 17% decrease in gas production volumes and a 3% decrease in average field-level prices. The 17% decrease in production volumes was primarily due to the Pinedale Divestiture, the Uinta Basin Divestiture and additional divestitures outside our main operating areas. These production decreases were partially offset by increases in production in Haynesville/Cotton Valley and the Permian Basin. The increase in gas production in Haynesville/Cotton Valley was due to the refracturing and drilling programs. The increase in production in the Permian Basin was due to increased drilling and completion activity, partially offset by lower gas capture rates in the Permian Basin due to midstream infrastructure construction and well connection activities in the area. The decrease in average field-level gas prices was driven by a decrease in average NYMEX-HH natural gas prices for the comparable period.

NGL sales. NGL sales were $110.9 million for the year ended December 31, 2018, a decrease of $1.0 million, or 1%, compared to 2017. This decrease was primarily a result of a 13% decrease in NGL production volumes, partially offset by a 14% increase in average field-level prices. The 13% decrease in NGL production volumes was primarily driven by the Pinedale Divestiture, declining gas volumes and lower ethane recovery in the Williston Basin and the Uinta Basin Divestiture. The 14% increase in average field-level prices was primarily driven by an increase in propane, ethane and other NGL component prices.

December 31, 2017 compared to December 31, 2016

Oil and condensate sales. Oil and condensate sales were $939.4 million for the year ended December 31, 2017, an increase of $170.3 million, or 22%, compared to 2016. This increase was a result of a 26% increase in average field-level oil prices, partially offset by a 3% decrease in oil and condensate production volumes. The increase in average field-level oil prices was driven by an increase in average NYMEX-WTI oil prices for the comparable period combined with narrowing differentials in our Northern Region properties. The 3% decrease in oil and condensate production volumes was primarily driven by a decrease in the Williston Basin due to a reduction in completion activity as well as operational issues, under performance by certain wells, and well shut-ins associated with completion activity and a decrease in Pinedale due to the Pinedale Divestiture, partially offset by an increase in the Permian Basin due to the late 2016 and 2017 acquisitions and increased completion activity.

Gas sales. Gas sales were $494.0 million for the year ended December 31, 2017, an increase of $76.9 million, or 18%, compared to 2016. This increase was a result of a 24% increase in average field-level prices, partially offset by a 5% decrease in gas production volumes. The increase in average field-level gas prices was driven by an increase in average NYMEX-HH natural gas prices for the comparable period. The 5% decrease in production volumes was primarily driven by the Pinedale Divestiture and a production decrease in the Uinta Basin due to reduced completion activity. These decreases were partially offset by increased production in Haynesville/Cotton Valley due to a well refracturing program that began in 2016 and continued throughout 2017 on QEP operated wells and two new operated well completions in 2017.

NGL sales. NGL sales were $111.9 million for the year ended December 31, 2017, an increase of $28.4 million, or 34%, compared to 2016. This increase was primarily a result of a 49% increase in average field-level prices, partially offset by a 10% decrease in NGL production volumes. The 49% increase in average field-level prices was primarily driven by an increase in propane, ethane and other NGL component prices. The 10% decrease in NGL production volumes was primarily driven by the Pinedale Divestiture and production decreases in the Uinta Basin due to lower gas volumes driven by reduced completion activity.

Resale Margin and Storage Activity

QEP purchases and resells oil and gas primarily to mitigate losses on unutilized capacity related to firm transportation commitments. The following table is a summary of QEP's financial results from its resale activities:

	Year Ended December 31,			Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
	(in millions)				
Purchased oil and gas sales	$48.8	$62.6	$101.2	$(13.8)	$(38.6)
Purchased oil and gas expense	(51.0)	(64.3)	(105.5)	13.3	41.2
Realized gains (losses) on gas storage derivative contracts	0.3	—	2.9	0.3	(2.9)
Resale margin	$(1.9)	$(1.7)	$(1.4)	$(0.2)	$(0.3)

Purchased oil and gas sales and expense decreased during the year ended December 31, 2018, compared to the year ended December 31, 2017, due to lower resale volumes needed to meet gas transportation commitments in the Southern Region due to increased production in the area and lower resale volumes following the sale of an underground gas storage facility in May 2018, partially offset by an increase in resale volumes to meet Northern Region gas transportation commitments retained in various divestitures.

Purchased oil and gas sales and expense decreased during the year ended December 31, 2017, compared to the year ended December 31, 2016, due to lower resale volumes, as a result of increased production in areas where the Company has oil and gas transportation commitments.

Operating Expenses

The following table presents QEP's production costs on a unit of production basis:

	Year Ended December 31,			Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
	(in millions)				
Lease operating expense	$263.1	$294.8	$224.7	$(31.7)	$70.1
Adjusted transportation and processing costs[1]	172.6	245.3	289.2	(72.7)	(43.9)
Production and property taxes	130.8	114.3	94.8	16.5	19.5
Total production costs	$566.5	$654.4	$608.7	$(87.9)	$45.7
	(per Boe)				
Lease operating expense	$5.07	$5.55	$4.03	$(0.48)	$1.52
Adjusted transportation and processing costs[1]	3.33	4.61	5.18	(1.28)	(0.57)
Production and property taxes	2.52	2.15	1.70	0.37	0.45
Total production costs	$10.92	$12.31	$10.91	$(1.39)	$1.40

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(1) Below are reconciliations of transportation and processing costs (a GAAP measure) as presented on the Consolidated Statements of Operations and on a unit of production basis to adjusted transportation and processing costs. Adjusted transportation and processing costs includes transportation and processing costs that are reflected as part of "Oil and condensate, gas and NGL sales" on the Consolidated Statements of Operations. Management adds these costs together with transportation and processing costs reflected on the Consolidated Statements of Operations to reflect the total operating costs associated with its production. Management believes that this non-GAAP measure is useful supplemental information for investors as it is reflective of the total production costs required to operate the wells for the period. This non-GAAP measure should be considered by the reader in addition to, but not instead of, the financial statements prepared in accordance with GAAP. Refer to Note 2 – Revenue in Item 8 of Part II of this Annual Report on Form 10-K for more information.

	Year Ended December 31,			Change	
	2018	2017[1]	2016[1]	2018 vs 2017	2017 vs 2016
	(in millions)				
Transportation and processing costs, as presented	$117.6	$245.3	$289.2	$(127.7)	$(43.9)
Transportation and processing costs deducted from oil and condensate, gas and NGL sales	55.0	—	—	55.0	—
Adjusted transportation and processing costs	$172.6	$245.3	$289.2	$(72.7)	$(43.9)
	(per Boe)				
Transportation and processing costs, as presented	$2.27	$4.61	$5.18	$(2.34)	$(0.57)
Transportation and processing costs deducted from oil and condensate, gas and NGL sales	1.06	—	—	1.06	—
Adjusted transportation and processing costs	$3.33	$4.61	$5.18	$(1.28)	$(0.57)

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(1) Prior period amounts have not been adjusted under the modified retrospective method for the new revenue recognition rule. Refer to Note 2 – Revenue in Item 8 of Part II of this Annual Report on Form 10-K for more information.

December 31, 2018 compared to December 31, 2017

Lease operating expense (LOE). QEP's LOE decreased $31.7 million, or $0.48 per Boe, during the year ended December 31, 2018 compared to 2017. The decrease in expense was driven by the Pinedale Divestiture and the Uinta Basin Divestiture. Refer to Note 3 – Acquisitions and Divestitures in Item 8 of Part II of this Annual Report on Form 10-K for more information. In addition, there was a decrease in workovers in the Williston and Permian basins and Haynesville/Cotton Valley and a decrease in water disposal and maintenance and repairs expenses in the Williston Basin. These decreases were partially offset by an increase in power and fuel, labor and maintenance and repairs expense in the Permian Basin.

Adjusted transportation and processing costs. QEP's adjusted transportation and processing costs decreased $72.7 million, or $1.28 per Boe, during the year ended December 31, 2018 compared to 2017. The decrease in expense during 2018 was primarily attributable to the Pinedale Divestiture and the Uinta Basin Divestiture. These decreases were partially offset by increased expenses in Haynesville/Cotton Valley and the Permian Basin due to increased production.

Production and property taxes. In most states in which QEP operates, QEP pays production taxes based on a percentage of field-level revenue, except in Louisiana, where severance taxes are volume based. Production and property taxes increased $16.5 million, or $0.37 per Boe, during 2018, primarily a result of increased oil and condensate revenues primarily in the Permian and Williston basins, partially offset by the Pinedale Divestiture.

Depreciation, depletion and amortization (DD&A). DD&A expense increased $102.6 million during the year ended December 31, 2018, compared to 2017. The increase in DD&A expense was primarily due to increased production and a higher DD&A rate in the Permian Basin and Haynesville/Cotton Valley, partially offset by lower DD&A due to the Pinedale and Uinta Basin divestitures and decreased production in the Williston Basin.

Exploration expense. Exploration expense decreased $21.7 million during the year ended December 31, 2018, compared to 2017, primarily as a result of $21.3 million of exploratory well costs in 2017 related to the Central Basin Platform exploration project. During the third quarter of 2017, based on well performance and the analysis of the ultimate economic feasibility of this exploration project, QEP determined it would no longer pursue the development of the Central Basin Platform exploration project. Refer to Note 4 – Capitalized Exploratory Well Costs in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Impairment expense. During the year ended December 31, 2018, QEP recorded impairment charges of $1,560.9 million, compared to $78.9 million of impairment charges recorded during 2017. Of the $1,560.9 million of impairment charges recorded during 2018, $1,559.3 million related to proved and unproved properties impairment resulting from signing purchase and sale agreements for the divestitures of the Williston Basin and Uinta Basin assets. Of the $78.9 million of impairment charges recorded during 2017, $38.1 million was related to impairment of proved properties due to lower gas prices, primarily in the Other Northern area, $29.0 million was related to expiring leaseholds on unproved properties, an impairment of $6.5 million was related to an underground gas storage facility, and $5.3 million related to an impairment of goodwill.

General and administrative (G&A) expense. During 2018, G&A expense increased $68.2 million, or 44%, compared to 2017. QEP incurred $61.0 million in costs associated with the implementation of our 2018 Strategic Initiatives of which $54.3 million was related to restructuring costs. Refer to Note 8 – Restructuring Costs in Item 8 of Part II of this Annual Report on Form 10-K for more information on restructuring costs. In addition to the $61.0 million of costs related to our 2018 Strategic Initiatives, QEP recognized a $14.7 million increase related to reduced overhead recoveries, primarily associated with our Pinedale Divestiture, a $6.5 million increase in share-based compensation and changes in the mark-to-market value of the nonqualified, unfunded deferred compensation plan (the Wrap Plan) and an increase in labor, benefits and employee expenses. These increases were partially offset by a $5.5 million decrease in legal expenses and loss contingencies and a $2.3 million decrease in outside services expenses.

Net gain (loss) from asset sales, inclusive of restructuring costs. During the year ended December 31, 2018, QEP recognized a gain on sale of assets of $25.0 million, compared to a gain on sale of $213.5 million during the year ended December 31, 2017. The gain on sale of assets recognized in 2018 was primarily related to a net pre-tax gain on sale of $38.5 million related to the divestiture of properties outside our main operating areas and an additional pre-tax gain on sale of $1.2 million related to the Pinedale Divestiture, partially offset by a pre-tax loss on sale of $12.6 million related to the Uinta Basin Divestiture, which included $5.4 million of restructuring costs. Refer to Note 8 – Restructuring Costs in Item 8 of Part II of this Annual Report on Form 10-K for more information. The gain on sale of assets recognized in 2017 was primarily related to the Pinedale Divestiture, in which we recorded a pre-tax gain on sale of $180.4 million, and the sale of Other Northern properties.

December 31, 2017 compared to December 31, 2016

Lease operating expense. QEP's LOE increased $70.1 million, or $1.52 per Boe, during the year ended December 31, 2017, compared to 2016. The increase was driven by an increase in workovers in the Williston and Permian basins and Haynesville/Cotton Valley, power and fuel expenses, and services and supplies expenses in the Permian Basin and increased water disposal expenses in Haynesville/Cotton Valley. These increases were partially offset by a decrease in Pinedale due to the Pinedale Divestiture. Refer to Note 3 – Acquisitions and Divestitures in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Adjusted transportation and processing costs. QEP's adjusted transportation and processing costs decreased $43.9 million, or $0.57 per Boe, during the year ended December 31, 2017, compared to 2016. The decrease in expense during 2017 was primarily attributable to decreases in Pinedale, primarily related to the Pinedale Divestiture and recovery of historical transportation costs, and in Haynesville/Cotton Valley related to the recovery of fees for historical unutilized gathering and transportation capacity that was charged to QEP by the operator of wells in which QEP had a working interest. These decreases were partially offset by increased expenses in Haynesville/Cotton Valley due to increased production and the Williston Basin due to higher transportation rates.

Production and property taxes. Production and property taxes increased $19.5 million, or $0.45 per Boe, during 2017, primarily a result of increased oil and condensate and gas revenues primarily from higher field-level prices, partially offset by lower production.

Depreciation, depletion and amortization. DD&A expense decreased $116.6 million during the year ended December 31, 2017, compared to 2016. The decrease in DD&A expense was due to decreases in Pinedale, the Williston Basin and the Uinta Basin, partially offset by increases in Haynesville/Cotton Valley and the Permian Basin. The decrease in Pinedale was primarily the result of a rate decrease due to an impairment recognized in the first quarter of 2016, combined with no DD&A expense in Pinedale during the second half of 2017 as the asset was considered held for sale and sold in September 2017. The decrease in the Williston Basin was the result of decreased production, partially offset by a rate increase from decreased proved reserves. The decrease in the Uinta Basin was the result of decreased production and a rate decrease from increased proved reserves. The increases in Haynesville/Cotton Valley and the Permian Basin were primarily due to increased production.

Exploration expense. Exploration expense increased $20.3 million during the year ended December 31, 2017, compared to 2016, primarily as a result of charging $21.3 million of exploratory well costs related to the Central Basin Platform exploration project to exploration expense. During the third quarter of 2017, based on well performance and the analysis of the ultimate economic feasibility of this exploration project, QEP determined it would no longer pursue the development of the Central Basin Platform exploration project. Refer to Note 4 – Capitalized Exploratory Well Costs in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Impairment expense. During the year ended December 31, 2017, QEP recorded impairment charges of $78.9 million, compared to impairment charges of $1,194.3 million recorded during 2016. Of the $78.9 million of impairment charges recorded during 2017, $38.1 million was related to impairment of proved properties due to lower gas prices, $29.0 million was related to expiring leaseholds on unproved properties, an impairment of $6.5 million was related to an underground gas storage facility and $5.3 million related to an impairment of goodwill. Of the $38.1 million impairment on proved properties, $37.1 million related to the Other Northern area and $1.0 million related to Louisiana properties. Of the $1,194.3 million of impairment charges recorded during 2016, $1,172.7 million was related to impairment of proved properties due to lower future oil and gas prices, $17.9 million was related to expiring leaseholds on unproved properties and $3.7 million related to an impairment of goodwill. Of the $1,172.7 million impairment on proved properties, $1,164.0 million related to Pinedale properties, $4.7 million related to Uinta Basin properties, $3.4 million related to Other Northern properties and $0.6 million related to QEP's remaining Other

Southern properties.

General and administrative expense. During 2017, G&A expense decreased $43.0 million, or 22%, compared to 2016. The decrease in G&A expense in 2017 compared to 2016 was primarily due to a $27.7 million decrease in legal expenses and loss contingencies and a $19.1 million decrease in share-based compensation, primarily due to a decrease in the value of the performance share unit plan. These decreases were partially offset by an increase in labor, benefits and employee expenses.

Net gain (loss) from asset sales, inclusive of restructuring costs. During the year ended December 31, 2017, QEP recognized a gain on sale of assets of $213.5 million, compared to a gain on sale of $5.0 million during the year ended December 31, 2016. The gain on sale of assets recognized in 2017 was primarily related to the Pinedale Divestiture, in which we recorded a pre-tax gain on sale of $180.4 million, and the sale of Other Northern properties. The gain on sale of assets recognized in 2016 was primarily due to the continued divestitures of properties in the Other Southern area.

Non-Operating Expenses

December 31, 2018 compared to December 31, 2017

Realized and unrealized gains (losses) on derivative contracts. Gains and losses on derivative contracts are comprised of both realized and unrealized gains and losses on QEP's commodity derivative contracts, which are marked-to-market each period. During the year ended December 31, 2018, gains on commodity derivative instruments were $90.4 million, of which $254.4 million were unrealized gains on derivative contracts related to production and storage contracts, $5.9 million were unrealized losses on derivative contracts related to the Uinta Basin Divestiture and $158.1 million were realized losses. During 2017, gains on commodity derivative instruments were $24.5 million, of which $69.9 million were unrealized gains on derivative contracts related to production and storage contracts, $29.9 million were unrealized losses related to the Pinedale Divestiture and $15.5 million were realized losses. Refer to Note 7 – Derivative Contracts in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Interest and other income (expense). Interest and other income (expense) decreased $11.2 million during the year ended December 31, 2018, compared to 2017. The decrease was primarily related to a $4.0 million loss on the Wrap Plan, an increased loss on sale of inventory of $3.3 million, an increase in pension expense of $2.7 million and a $1.3 million decrease in interest income due to lower average balances on commercial paper.

Loss from early extinguishment of debt. Loss from early extinguishment of debt decreased $32.7 million during the year ended December 31, 2018, compared to 2017. The 2017 loss was the result of the early repayment of senior notes during the year ended December 31, 2017. Refer to Note 9 – Debt in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Interest expense. Interest expense increased $11.6 million, or 8%, during the year ended December 31, 2018, compared to 2017. The increase during the year ended December 31, 2018, was primarily related to increased interest on borrowings under the credit facility, partially offset by lower aggregate average interest rates on our senior notes.

Income tax (provision) benefit. Income tax benefit increased $5.2 million during the year ended December 31, 2018, compared to 2017. The increase in income tax benefit was the result of increased net loss before income taxes, partially offset by the federal rate change from 35% to 21% as a result of the federal tax reform and change in state income tax, which resulted in a combined effective federal and state income tax rate of 23.9% during the year ended December 31, 2018, compared to 727.7% for the year ended December 31, 2017.

December 31, 2017 compared to December 31, 2016

Realized and unrealized gains (losses) on derivative contracts. During the year ended December 31, 2017, gains on commodity derivative instruments were $24.5 million, of which $69.9 million were unrealized gains on derivative contracts related to production and storage contracts, $29.9 million were unrealized losses related to the Pinedale Divestiture (refer to Note 7 – Derivative Contracts in Item 8 of Part II of this Annual Report on Form 10-K for more information) and $15.5 million were realized losses. During 2016, losses on commodity derivative instruments were $233.0 million, of which $367.0 million were unrealized losses, partially offset by $134.0 million of realized gains.

Interest and other income (expense). Interest and other income (expense) decreased $22.1 million during the year ended December 31, 2017, compared to 2016. The decrease was primarily the result of $22.6 million of bargain purchase gains recognized in 2016 that related to acquisitions which were accounted for as a business combination under ASC 805, Business Combinations during the year ended December 31, 2016. Refer to Note 3 – Acquisitions and Divestitures in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Loss from early extinguishment of debt. Loss from early extinguishment of debt increased $32.7 million during the year ended December 31, 2017, compared to 2016. The increase during the year ended December 31, 2017, was primarily the result of the early repayment of senior notes. Refer to Note 9 – Debt in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Interest expense. Interest expense decreased $5.4 million, or 4%, during the year ended December 31, 2017, compared to 2016. The decrease during the year ended December 31, 2017, was primarily related to the repayment of the 6.05% senior notes in September 2016.

Income tax (provision) benefit. Income tax benefit decreased $396.0 million during the year ended December 31, 2017, compared to 2016. The decrease in income tax benefit was the result of a decreased net loss before income taxes, partially offset by the federal rate change from 35% to 21% as a result of the federal tax reform and a change in state income tax, which resulted in a combined effective federal and state income tax rate of 727.7% during the year ended December 31, 2017, compared to 36.3% for the year ended December 31, 2016.

LIQUIDITY AND CAPITAL RESOURCES

QEP strives to maintain sufficient liquidity to ensure financial flexibility, withstand commodity price volatility and fund its development projects, operations, capital expenditures and strategic initiatives. The Company utilizes derivative contracts to reduce the financial impact of commodity price volatility and provide a level of certainty to the Company's cash flows. QEP generally funds its operations and planned capital expenditures with cash flow from its operating activities, cash on hand and borrowings under its revolving credit facility. QEP also periodically accesses debt and equity markets and sells properties to enhance its liquidity. The Company expects that cash flows from its operating activities, cash on hand and borrowings under its revolving credit facility will be sufficient to fund its operations and capital expenditures during the next 12 months and the foreseeable future.

In January 2019, QEP closed the Haynesville Divestiture for net cash proceeds of $605.1 million, subject to post-closing purchase price adjustments. In addition, $32.2 million was placed in escrow due to title defects asserted prior to closing, all or a portion of which QEP expects to receive pursuant to the purchase and sale agreement's title dispute resolution procedures. QEP used the proceeds to repay the outstanding balance on its revolving credit facility and for general corporate purposes.

During the year ended December 31, 2018, QEP received cash proceeds of $243.6 million from the Uinta Basin Divestiture as well as the divestiture of other assets outside its main operating areas and used the net cash proceeds to pay down long-term debt outstanding under QEP's revolving credit facility. To the extent that the Company sells additional assets, the Company plans to use the proceeds to fund on-going operations, reduce debt, repurchase shares and for general corporate purposes.

During the year ended December 31, 2017, QEP received aggregate proceeds of approximately $806.8 million related to the Pinedale Divestiture and the divestiture of other assets outside its main operating areas. All of the proceeds from the Pinedale Divestiture were used to close the 2017 Permian Basin Acquisition.

In 2016, QEP issued 60.95 million shares of common stock through two public offerings and received net cash proceeds of approximately $781.4 million, which the Company used to fund the 2016 Permian Basin Acquisition and for general corporate purposes. QEP received aggregate cash proceeds of approximately $29.0 million related to the sale of non-core properties during the year ended December 31, 2016.

The Company estimates, that as of December 31, 2018, it could incur additional indebtedness of approximately $819.7 million and be in compliance with the covenants contained in its revolving credit facility. In January 2019, as a result of a downgrade in the ratings of our senior notes, the Company became subject to the present value coverage ratio, which may significantly reduce the additional indebtedness that could be incurred. To the extent actual operating results, realized commodity prices or uses of cash differ from the Company's assumptions, QEP's liquidity could be adversely affected.

Credit Facility

QEP's revolving credit facility, which matures, subject to satisfaction of certain conditions, in September 2022, provides for loan commitments of $1.25 billion. The credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions. The credit agreement contains financial covenants (that are defined in the credit agreement) that limit the amount of debt the Company can incur and may limit the amount available to be drawn under the credit facility including: (i) a net funded debt to capitalization ratio that may not exceed 60%, (ii) a leverage ratio under which net funded debt may not exceed 4.00 times consolidated EBITDA (as defined in the credit agreement), through the fiscal quarter ending December 31, 2018, and 3.75 times thereafter, and (iii) during a ratings trigger period (as defined), a present value coverage ratio under which the present value of the Company's proved reserves must exceed net funded debt by 1.40 times commencing on January 1, 2019 through December 31, 2019, and must exceed net funded debt by 1.50 times at any time on or after January 1, 2020. As of December 31, 2018, the Company was not subject to the present value coverage ratio; however, as of January 2019, the Company is in a ratings trigger period and subject to the present value coverage ratio. As of December 31, 2018 and 2017, QEP was in compliance with the covenants under the credit agreement.

During the year ended December 31, 2018, QEP's weighted-average interest rate on borrowings from its credit facility was 4.43%. As of December 31, 2018, QEP had $430.0 million outstanding and $0.3 million in letters of credit outstanding under the credit facility. As of December 31, 2017, QEP had $89.0 million outstanding and $1.0 million in letters of credit outstanding under the credit facility. As of February 15, 2019, QEP had no borrowings outstanding and had $0.3 million of letters of credit outstanding under the credit facility and was in compliance with the covenants under the credit agreement.

Senior Notes

The Company's senior notes outstanding as of December 31, 2018, totaled $2,099.3 million principal amount and are comprised of five issuances as follows:

- $51.7 million 6.80% Senior Notes due March 2020;
- $397.6 million 6.875% Senior Notes due March 2021;
- $500.0 million 5.375% Senior Notes due October 2022;
- $650.0 million 5.25% Senior Notes due May 2023; and
- $500.0 million 5.625% Senior Notes due March 2026.

Cash Flow from Operating Activities

Cash flows from operating activities are primarily affected by oil and condensate, gas and NGL production volumes and commodity prices (including the effects of settlements of the Company's derivative contracts) and by changes in working capital. QEP typically enters into commodity derivative transactions covering a substantial, but varying, portion of its anticipated future oil and condensate and gas production for the next 12 to 36 months.

Net cash provided by (used in) operating activities is presented below:

	Year Ended December 31,			Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
	(in millions)				
Net income (loss)	$(1,011.6)	269.3	$(1,245.0)	$(1,280.9)	$1,514.3
Non-cash adjustments to net income (loss)	1,942.6	335.8	1,794.1	1,606.8	(1,458.3)
Changes in operating assets and liabilities	(114.8)	(4.9)	118.1	(109.9)	(123.0)
Net cash provided by (used in) operating activities	$816.2	$600.2	$667.2	$216.0	$(67.0)

Net cash provided by operating activities during the year ended December 31, 2018, increased $216.0 million compared to 2017, which included a $1,280.9 million increase in net loss, a $1,606.8 million increase in non-cash adjustments to the net loss, and a $109.9 million increase in cash from operating assets and liabilities. During the year ended December 31, 2018, non-cash adjustments to net loss primarily included impairment expense of $1,560.9 million, DD&A expense of $857.1 million and share-based compensation expense of $39.1 million, partially offset by the fair value of unrealized gains on derivative contracts of $248.5 million, deferred income taxes of $247.6 million and a $25.0 million net gain from asset sales. The increase in changes in operating assets and liabilities of $114.8 million was primarily comprised of a decrease in accounts payable and accrued expenses of $74.2 million and a decrease in accrued income taxes of $71.0 million. These decreases were partially offset by a decrease in accounts receivable of $33.7 million.

Net cash provided by operating activities during the year ended December 31, 2017, decreased $67.0 million compared to 2016, which included a $1,514.3 million decrease in net loss, a $1,458.3 million decrease in non-cash adjustments to the net loss and a $123.0 million increase in cash from operating assets and liabilities. During the year ended December 31, 2017, non-cash adjustments to net loss primarily included DD&A expense of $754.5 million, impairment expense of $78.9 million and a $32.7 million loss from early extinguishment of debt, partially offset by deferred income taxes of $314.8 million and $213.5 million net gain from sales. The decrease in changes in operating assets and liabilities of $4.9 million was primarily comprised of an $18.8 million decrease in other that predominantly included decreases in interest payable and asset retirement obligation as well as an increase in accounts receivable of $2.0 million, primarily related to timing of receipts. These decreases were partially offset by a decrease in federal income taxes receivable of $13.7 million and an increase in accounts payable and accrued expenses of $3.5 million.

Cash Flow from Investing Activities

A comparison of capital expenditures for the years ended December 31, 2018, 2017 and 2016, are presented in the table below:

	Year Ended December 31,			Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
	(in millions)				
Property acquisitions	$65.6	$815.2	$645.2	$(749.6)	$170.0
Property, plant and equipment capital expenditures	1,176.6	1,219.8	530.1	(43.2)	689.7
Total accrued capital expenditures	1,242.2	2,035.0	1,175.3	(792.8)	859.7
Change in accruals and other non-cash adjustments	57.4	(60.2)	32.8	117.6	(93.0)
Total cash capital expenditures	$1,299.6	$1,974.8	$1,208.1	$(675.2)	$766.7

During the year ended December 31, 2018, on an accrual basis, the Company invested $1,176.6 million on property, plant and equipment capital expenditures, excluding property acquisitions, a decrease of $43.2 million compared to 2017, primarily due to decreased capital expenditures in the Williston Basin and Haynesville/Cotton Valley. In 2018, QEP's capital expenditures were $852.9 million in the Permian Basin (including midstream infrastructure of $75.5 million, primarily related to oil and gas gathering), $188.8 million in the Williston Basin, $117.8 million in Haynesville/Cotton Valley and $5.3 million in the Uinta Basin. In addition, during the year ended December 31, 2018, QEP acquired various oil and gas properties for a total purchase price of $65.6 million, which was primarily related to the 2017 Permian Basin Acquisition and included proved and unproved leasehold acreage in the Permian Basin. These acquisitions were primarily funded through borrowings under QEP's revolving credit facility.

During the year ended December 31, 2017, on an accrual basis, the Company invested $1,219.8 million on property, plant and equipment expenditures, excluding property acquisitions, an increase of $689.7 million compared to 2016, primarily due to increased capital expenditures in the Permian Basin and Haynesville/Cotton Valley. In 2017, QEP's capital expenditures were $704.3 million in the Permian Basin (including midstream infrastructure of $96.6 million, primarily related to oil and gas gathering), $283.5 million in the Williston Basin, $179.5 million in Haynesville/Cotton Valley, $22.9 million in Pinedale and $3.7 million in the Uinta Basin. In addition, during the year ended December 31, 2017, QEP acquired various oil and gas properties for a total purchase price of $815.2 million, which was primarily related to the 2017 Permian Basin Acquisition and included undeveloped leasehold acreage, producing wells and additional surface acreage in the Permian Basin. These acquisitions were primarily funded with proceeds of approximately $806.8 million from the Pinedale Divestiture and the sale of other assets.

The mid-point of our 2019 forecasted capital expenditures is $640.0 million. QEP intends to fund capital expenditures with cash flow from operating activities, cash on hand and borrowings under the credit facility. The aggregate levels of capital expenditures for 2019 and the allocation of those expenditures are dependent on a variety of factors, including drilling results, oil, gas and NGL prices, industry conditions, the extent to which properties or working interests are acquired or divested, the availability of capital resources to fund the expenditures; changes in management's business assessments as to where QEP's capital can be most profitably deployed; and plans or transactions resulting from our review of strategic alternatives. Accordingly, the actual levels of capital expenditures and the allocation of those expenditures may vary materially from QEP's estimates.

Cash Flow from Financing Activities

During the year ended December 31, 2018, net cash provided by financing activities was $244.6 million compared to net cash provided by financing activities of $125.8 million during the year ended December 31, 2017. During the year ended December 31, 2018, QEP had borrowings from the credit facility of $3,608.0 million and repayments on its credit facility of $3,267.0 million. In addition, QEP used $58.4 million of cash to repurchase and retire common stock under the Company's share repurchase program and had treasury stock repurchases of $8.7 million related to the settlement of income tax and related benefit withholding obligations arising from the vesting of restricted share grants. During 2018, QEP had a decrease in checks outstanding in excess of cash balances of $29.5 million. As of December 31, 2018, long-term debt consisted of $2,507.1 million total debt, of which $2,099.3 million is senior notes, $430.0 million is outstanding on the credit facility, and $22.2 million is net original issue discount and unamortized debt issuance costs.

During the year ended December 31, 2017, net cash provided by financing activities was $125.8 million compared to net cash provided by financing activities of $583.1 million during the year ended December 31, 2016. During the year ended December 31, 2017, the Company issued 5.625% Senior Notes due 2026 receiving gross cash proceeds of $500.0 million, and repaid $445.7 million of Senior Notes comprised of the redemption of the 6.80% Senior Notes due 2018 and settling the tender offers of the 6.80% Senior Notes due 2020 and 6.875% Senior Notes due 2021. In addition, during the year ended December 31, 2017, QEP had borrowings from the credit facility of $492.0 million and repayments on its credit facility of $403.0 million. As of December 31, 2017, long-term debt consisted of $2,160.8 million total debt, of which $2,099.3 million is senior notes, $89.0 million outstanding on the credit facility, and $27.5 million of net original issue discount and unamortized debt issuance costs.

Off-Balance Sheet Arrangements

QEP may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. At December 31, 2018, the Company's material off-balance sheet arrangements included operating leases; drilling, gathering, processing and firm transportation; and undrawn letters of credit. There are no other off-balance sheet arrangements that have or are reasonably likely to have a current or future material effect on QEP's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources. See "Contractual Cash Obligations and Other Commitments" below for more information regarding QEP's off-balance sheet arrangements.

Contractual Cash Obligations and Other Commitments

In the course of ordinary business activities, QEP enters into a variety of contractual cash obligations and other commitments. The following table summarizes the significant contractual cash obligations as of December 31, 2018:

	Payments Due by Year[1]						
	Total	2019	2020	2021	2022	2023	After 2023
	(in millions)						
Long-term debt	$2,099.3	$—	$51.7	$397.6	$500.0	$650.0	$500.0
Interest on fixed-rate, long-term debt[2]	513.4	119.9	117.0	93.7	82.4	39.5	60.9
Drilling contracts	2.0	2.0	—	—	—	—	—
Gathering, processing, firm transportation and other	265.3	70.2	55.4	31.3	27.1	15.3	66.0
Asset retirement obligations[3]	159.6	5.8	3.6	2.7	3.5	3.9	140.1
Building, compressor, generator and equipment operating leases	52.2	17.4	13.8	9.1	7.4	4.5	—
Total	$3,091.8	$215.3	$241.5	$534.4	$620.4	$713.2	$767.0

(1) This table excludes the Company's benefit plan liabilities as future payment dates are unknown. Refer to Note 12 – Employee Benefits in Item 8 of Part II of this Annual Report on Form 10-K for more information.

(2) Excludes variable rate debt interest payments and commitment fees related to the Company's revolving credit facility.

(3) These future obligations are discounted estimates of future expenditures based on expected settlement dates. Refer to Note 5 – Asset Retirement Obligations in Item 8 of Part II in this Annual Report on Form 10-K for more information.

Impact of Inflation/Deflation and Pricing

All of QEP's transactions are denominated in U.S. dollars. Typically, as prices for oil and gas increase, associated costs rise. Conversely, as prices for oil and gas decrease, costs decline. Cost declines tend to lag and may not adjust downward in proportion to declining commodity prices. Historically, field-level prices received for QEP's oil and gas production have been volatile. During each of the years ended December 31, 2018, 2017 and 2016, commodity prices increased from the previous year. Changes in commodity prices impact QEP's revenues, estimates of reserves, assessments of any impairment of oil and gas properties, as well as values of properties being acquired or sold. Price changes have the potential to affect QEP's ability to raise capital, borrow money, and retain personnel.

Critical Accounting Estimates

QEP's significant accounting policies are described in Note 1 – Summary of Significant Accounting Policies, in Item 8 of Part II of this Annual Report on Form 10-K. The Company's Consolidated Financial Statements are prepared in accordance with GAAP. The preparation of consolidated financial statements requires management to make assumptions and estimates that affect the reported results of operations and financial position. The following is a discussion of the accounting policies, estimates and judgments that management believes are most significant in the application of GAAP used in the preparation of the Company's financial statements.

Oil and condensate, gas and NGL Reserves
One of the most significant estimates the Company makes is the estimate of proved oil and condensate, gas and NGL reserves. Oil and condensate, gas and NGL reserve estimates require significant judgments in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may change substantially over time as a result of numerous factors including, but not limited to, additional development activity, production history, projected future production, economic assumptions relating to commodity prices, development costs, operating expenses, severance and other taxes, capital expenditures and remediation costs. The subjective judgments and variances in data for various fields make these estimates less precise than other estimates included in the financial statement disclosures.

Estimates of proved oil and condensate, gas and NGL reserves significantly affect the Company's DD&A expense. For example, if estimates of proved reserves decline, the Company's DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves could also cause QEP to perform an impairment analysis to determine if the carrying value of our oil and gas properties exceeds fair value, which could result in an impairment charge that would reduce earnings. See "Impairment of Long-Lived Assets" below.

QEP engages independent reservoir engineering consultants to prepare estimates of the proved oil and condensate, gas and NGL reserves. Reserve estimates are based on a complex and highly interpretive process that is subject to continuous revision as additional production and development drilling information becomes available. Refer to Note 15 – Supplemental Oil and Gas Information (unaudited) in Item 8 of Part II of this Annual Report on Form 10-K.

Successful Efforts Accounting for Oil and Gas Operations
The Company follows the successful efforts method of accounting for oil and gas property acquisitions, exploration, development and production activities. Under this method, the acquisition costs of proved and unproved properties, successful exploratory wells and development wells are capitalized. Other exploration costs, including geological and geophysical costs, delay rentals and administrative costs associated with unproved property and unsuccessful exploratory well costs are expensed. Costs to operate and maintain wells and field equipment are expensed as incurred. A gain or loss is generally recognized only when an entire field is sold or abandoned, or if the unit-of-production DD&A rate would be significantly affected. Capitalized costs of unproved properties are reclassified to proved property when related proved reserves are determined or charged against the impairment allowance when abandoned.

Impairment of Long-Lived Assets
Proved oil and gas properties are evaluated on a field-by-field basis for potential impairment. Other properties are evaluated on a specific asset basis or in groups of similar assets, as applicable. Impairment is indicated when a triggering event occurs and/or the sum of the estimated undiscounted future net cash flows of an evaluated asset is less than the asset's carrying value. Triggering events could include, but are not limited to, a reduction of oil and condensate, gas and NGL reserves caused by mechanical problems, faster-than-expected decline of production, lease ownership issues, potential divestiture of assets and declines in oil, gas and NGL prices. If impairment is indicated, fair value is estimated using a discounted cash flow approach. Cash flow estimates require forecasts and assumptions

for many years into the future for a variety of factors, including commodity prices, operating costs and estimates of proved, probable and possible reserves. If a range is estimated for the amount of possible future cash flows, the fair value of property is measured utilizing a probability-weighted approach whereas the likelihood of possible outcomes is taken into consideration. Specific to the Planned Williston Basin Divestiture, the Company obtained a Black-Scholes-Merton estimate of the value of the contractual rights to receive up to 5.8 million shares of the buyer's common stock at December 31, 2018. Cash flow estimates relating to future cash flows from probable and possible reserves are reduced by additional risk-weighting factors. During the years ended December 31, 2018, 2017 and 2016, QEP recorded impairment expense of $1,524.6 million, $38.1 million and $1,172.7 million, respectively. The impairment recorded during the year ended December 31, 2018 was primarily the result of signing purchase and sale agreements related to the Planned Williston Basin Divestiture and the Uinta Basin Divestiture. During the years ended December 31, 2017 and 2016 the impairment recorded related to some of its higher cost, proved properties in both of its Northern and Southern regions, due to lower forward prices.

Unproved properties are evaluated on a specific asset basis or in groups of similar assets, as applicable. The Company performs periodic assessments of unproved oil and gas properties for impairment and recognizes a loss at the time of impairment. In determining whether an unproved property is impaired, the Company considers numerous factors including, but not limited to, current development and exploration drilling plans, favorable or unfavorable exploration activity on adjacent leaseholds, in-house geologists' evaluation of the lease, future reserve cash flows and the remaining lease term. During the years ended December 31, 2018, 2017 and 2016, QEP recorded impairment charges of $36.3 million, $29.0 million and $17.9 million respectively, related to its unproved properties. The 2018 unproved property impairment charges primarily resulted from unproved leasehold acreage in the Williston and Uinta basins. The 2017 unproved property impairment charges primarily resulted from unproved leasehold acreage in the Central Basin Platform. Refer to Note 4 – Capitalized Exploratory Well Costs in Item 8 of Part II of this Annual Report on Form 10-K for more information. The 2016 unproved property impairment charges primarily resulted from lower forward prices and expiring leaseholds.

Asset Retirement Obligations
QEP records asset retirement obligations (ARO) associated with the retirement of tangible, long-lived assets. The Company's ARO liability applies primarily to abandonment costs associated with oil and gas wells and certain other properties. The fair values of such costs are estimated by Company personnel based on abandonment costs of similar assets and depreciated over the life of the related assets. ARO is subject to revisions because of the intrinsic uncertainties present when estimating asset retirement costs and asset retirement settlement dates. Revisions to the ARO estimate can result from changes in expected cash flows or material changes in estimated asset retirement costs. The ARO liability is adjusted to present value each period through an accretion calculation using a credit-adjusted risk-free interest rate. QEP's ARO liability at December 31, 2018 and 2017 was $159.6 million and $214.1 million, respectively, and is included in "Asset retirement obligations" and "Other long-term liabilities held for sale" on the Consolidated Balance Sheets.

Accounting for ARO represents a critical accounting estimate because (i) QEP will not incur most of these costs for a number of years, requiring QEP to make estimates over a long period, (ii) laws and regulations could change in the future and/or circumstances affecting QEP's operations could change, either of which could result in significant changes to its current plans, (iii) the methods used or required to plug and abandon non-producing oil and gas wellbores, remove platforms, tanks, production equipment and flow lines, and restore the well site could change, (iv) calculating the fair value of QEP's ARO requires management to estimate projected cash flows, make long-term assumptions about inflation rates, determine its credit-adjusted risk-free interest rates and determine market risk premiums that are appropriate for its operations, and (v) changes in any or all of these estimates could have an impact on QEP's results of operations.

Revenue Recognition
We recognize revenue from the sales of oil and condensate, gas and NGL in the period that the performance obligations are satisfied. Our performance obligations are satisfied when the customer obtains control of product, when we have no further obligations to perform related to the sale, when the transaction price has been determined and when collectability is probable. The sales of oil and condensate, gas and NGL are made under contracts with customers, which typically include consideration that is based on pricing tied to local indices and volumes delivered in the current month. Reported revenues include estimates for the two most recent months using published commodity price indexes and volumes supplied by field operators. Performance obligations under our contracts with customers are typically satisfied at a point in time through monthly delivery of oil and condensate, gas and/or NGL. Our contracts with customers typically require payment for oil and condensate, gas and NGL sales within 30 days following the calendar month of delivery.

Our oil is typically sold at specific delivery points under contract terms that are common in our industry. Our gas and NGL are also sold under contract types that are common in our industry; however, under these contracts, the gas and its components, including NGL, may be sold to a single purchaser or the residue gas and NGL may be sold to separate purchasers. Regardless of the contract type, the terms of these contracts compensate the Company for the value of the residue gas and NGL constituent components at market prices for each product. We purchase and resell oil to mitigate credit risk related to third party purchasers, to fulfill volume commitments when our production does not fulfill contractual commitments, and to capture additional margin from subsequent sales of third party purchases. We recognize revenue from these resale activities in the period that the performance obligations are satisfied.

Litigation and Other Contingencies

The Company is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business. In each reporting period, the Company assesses these claims in an effort to determine the degree of probability and range of potential loss for potential accrual in its Consolidated Financial Statements. In accordance with ASC 450, Contingencies, an accrual is recorded for a material loss contingency when its occurrence is probable and damages can be reasonably estimable based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes.

Legal proceedings are inherently unpredictable, and unfavorable resolutions can occur. Assessing contingencies is highly subjective and requires judgments about uncertain future events. When evaluating contingencies related to legal proceedings, the Company may be unable to estimate losses due to a number of factors, including potential defenses, the procedural status of the matter in question, the presence of complex legal and/or factual issues, the ongoing discovery and/or development of information important to the matter. Refer to Note 10 – Commitments and Contingencies in Item 8 of Part II of this Annual Report on Form 10-K for more information regarding litigation and other contingencies.

Derivative Contracts
The Company uses commodity derivative instruments, typically fixed-price swaps and costless collars, to reduce the impact of potential downward movements in commodity prices. Accounting rules for derivatives require marking these instruments to fair value at the balance sheet reporting date. The Company follows mark-to-market accounting and recognizes all gains and losses on such instruments in earnings in the period in which they occur. As a result, changes in the fair value of QEP's commodity derivative instruments could have a significant impact on net income. QEP does not engage in speculative hedging transactions, nor does it buy and sell energy contracts with the objective of generating profits on short-term differences in price. Refer to Note 7 – Derivative Contracts in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Pension and Other Postretirement Benefits
QEP maintains a closed, defined-benefit pension and other postretirement benefit plans, including both a qualified and a supplemental plan. QEP also provides certain health care and life insurance benefits for certain retired QEP employees. Determination of the benefit obligations for QEP's defined-benefit pension and other postretirement benefit plans impacts the recorded amounts for such obligations on the Consolidated Balance Sheets and the amount of benefit expense recorded on the Consolidated Statements of Operations.

QEP measures pension plan assets at fair value. Defined-benefit plan obligations and costs are actuarially determined, incorporating the use of various assumptions. Critical assumptions for pension and other postretirement benefit plans include the discount rate, the expected rate of return on plan assets (for funded pension plans) and the rate of future compensation increases. Other assumptions involve demographic factors such as retirement, mortality and turnover. QEP evaluates and updates its actuarial assumptions at least annually. QEP recognizes a pension curtailment immediately when there is a significant reduction in, or an elimination of, defined-benefit accruals for present employees' future services. Refer to Note 12 – Employee Benefits in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Share-Based Compensation
QEP issues stock options, restricted share awards and restricted share units to certain officers, employees and non-employee directors under its 2018 Long-Term Incentive Plan (LTIP). QEP uses the Black-Scholes-Merton mathematical model to estimate the fair value of stock options for accounting purposes. The grant date fair value for restricted share awards is determined based on the closing bid price of the Company's common stock on the grant date. Share-based compensation cost for restricted share units is equal to its fair value as of the end of the period and is classified as a liability. QEP uses an accelerated method in recognizing share-based compensation costs for stock options and restricted share awards with graded-vesting periods. Stock options held by employees generally vest in three equal, annual installments and primarily have a term of seven years. Restricted share awards and restricted share units vest in equal installments over a specified number of years after the grant date with the majority vesting in three years. Non-vested restricted share awards have voting and dividend rights; however, sale or transfer is restricted. Employees may elect to defer their grants of restricted share awards and these deferred awards are designated as restricted share units. Restricted share units vest over a three-year period and are deferred into the Company's nonqualified unfunded deferred compensation plan at the time of vesting. The Company also awards performance

share units under its Cash Incentive Plan (CIP) that are generally paid out in cash depending upon the Company's total shareholder return compared to a group of its peers over a three-year period. Share-based compensation cost for the performance share units is equal to its fair value as of the end of the period and is classified as a liability. Refer to Note 11 – Share-Based Compensation in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Income Taxes
The amount of income taxes recorded by QEP requires interpretations of complex rules and regulations of various tax jurisdictions throughout the United States. QEP has recognized deferred tax assets and liabilities for temporary differences, operating losses and tax credit carryforwards. QEP routinely assesses the realizability of its deferred tax assets and reduces such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. QEP routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts. The accruals for deferred tax assets and liabilities, including deferred state income tax assets and liabilities, are subject to significant judgment by management and are reviewed and adjusted routinely based on changes in facts and circumstances. Although management considers its tax accruals adequate, material changes in these accruals may occur in the future, based on the impact of tax audits, changes in legislation and resolution of pending or future tax matters. Refer to Note 13 – Income Taxes in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Purchase Price Allocations
QEP periodically acquires assets and assumes liabilities in transactions accounted for as business combinations, such as the 2016 Permian Basin Acquisition. In connection with a business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Any excess or shortage of amounts assigned to assets and liabilities over or under the purchase price is recorded as a bargain purchase gain or goodwill. The amount of goodwill or bargain purchase gain recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed and fluctuations in commodity prices.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, QEP makes various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved oil and gas properties. If sufficient market data is not available regarding the fair values of proved and unproved properties, QEP must prepare estimates. To estimate the fair values of these properties, QEP utilizes a discounted cash flow model which utilizes the following inputs to estimate future net cash flows: estimated quantities of oil and condensate, gas and NGL reserves; estimates of future commodity prices; and estimated production rates, future operating and development costs, which are based on the Company's historic experience with similar properties. The future net cash flows are discounted using a market-based weighted-average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted-average cost of capital rate is subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, when a discounted cash flow model is used, the discounted future net cash flows of probable and possible reserves are reduced by additional risk factors. In some instances, market comparable information of recent transactions is used to estimate fair value of unproved acreage.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in higher DD&A expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value, or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded. Refer to Note 3 – Acquisitions and Divestitures in Item 8 of Part II of this Annual Report on Form 10-K for more information regarding purchase price allocations.

Recent Accounting Developments

See Recent Accounting Developments in Note 1 – Summary of Significant Accounting Policies in Item 8 of Part II of this Annual Report on Form 10-K.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

QEP's primary market risks arise from changes in the market price for oil, gas and NGL and volatility in interest rates. These risks can affect revenues and cash flows from operating, investing and financing activities. Commodity prices have historically been volatile and are subject to wide fluctuations in response to relatively minor changes in supply and demand. If commodity prices fluctuate significantly, revenues and cash flow may significantly decrease or increase. QEP has long-term contracts for pipeline capacity and is obligated to pay for transportation services with no guarantee that it will be able to fully utilize the contractual capacity of these transportation commitments. In addition, additional non-cash impairment expense of the Company's oil and gas properties may be required if future oil and gas commodity prices experience a significant decline. Furthermore, the Company's revolving credit facility has a floating interest rate, which exposes QEP to interest rate risk if QEP has borrowings outstanding. To partially manage the Company's exposure to these risks, QEP enters into commodity derivative contracts in the form of fixed-price and basis swaps and collars to manage commodity price risk and periodically enters into interest rate swaps to manage interest rate risk.

Commodity Price Risk Management

QEP uses commodity derivative instruments in the normal course of business to reduce the risk of adverse commodity price movements. However, these arrangements typically limit future gains from favorable price movements. The types of commodity derivative instruments currently utilized by the Company are fixed-price and basis swaps and collars. The volume of commodity derivative instruments utilized by the Company may vary from year to year based on QEP's forecasted production. The Company's current derivative instruments do not have margin requirements or collateral provisions that would require payments prior to the scheduled cash settlement dates. As of December 31, 2018, QEP held commodity price derivative contracts, excluding basis swaps, totaling 13.9 million barrels of oil and 43.8 million MMBtu of gas. As of December 31, 2017, QEP held commodity price derivative contracts, excluding basis swaps, totaling 24.8 million barrels of oil, and 147.8 million MMBtu of gas.

The following table presents QEP's volumes and average prices for its derivative positions as of February 15, 2019. Refer to Note 7 – Derivative Contracts in Item 8 of Part II of this Annual Report on Form 10-K for open derivative positions as of December 31, 2018.

Production Commodity Derivative Swaps

Year	Index	Total Volumes	Average Swap Price per Unit
		(in millions)	
Oil sales		(bbls)	($/bbl)
2019	NYMEX WTI	10.6	$ 54.61
2020	NYMEX WTI	4.4	$ 60.22

Production Commodity Derivative Basis Swaps

Year	Index	Basis	Total Volumes (in millions)	Weighted-Average Differential
Oil sales			(bbls)	($/bbl)
2019	NYMEX WTI	Argus WTI Midland	6.0	$ (2.22)
2019	NYMEX WTI	Argus WTI Houston	0.7	$ 3.80
2020	NYMEX WTI	Argus WTI Midland	1.8	$ (0.80)

Changes in the fair value of derivative contracts from December 31, 2017 to December 31, 2018, are presented below:

	Commodity derivative contracts
	(in millions)
Net fair value of oil and gas derivative contracts outstanding at December 31, 2017	$ (131.9)
Contracts settled	158.1
Change in oil and gas prices on futures markets	469.8
Contracts added	(373.5)
Net fair value of oil and gas derivative contracts outstanding at December 31, 2018	$ 122.5

The following table shows the sensitivity of the fair value of oil and gas derivative contracts to changes in the market price of oil, gas and basis differentials:

	December 31, 2018
	(in millions)
Net fair value – asset (liability)	$ 122.5
Fair value if market prices of oil, gas and basis differentials decline by 10%	$ 110.3
Fair value if market prices of oil, gas and basis differentials increase by 10%	$ 134.8

Utilizing the actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these instruments by $12.3 million, while a 10% decrease in underlying commodity prices would increase the fair value of these instruments by $12.2 million as of December 31, 2018. However, a gain or loss eventually would be offset by the actual sales value of the physical production covered by the derivative instruments. For more information regarding the Company's commodity derivative transactions, refer to Note 7 – Derivative Contracts in Item 8 of Part II of this Annual Report on Form 10-K.

Interest Rate Risk Management

The Company's ability to borrow and the rates offered by lenders can be adversely affected by illiquid credit markets and the Company's credit rating, as described in the Risk Factors, in Item 1A of Part I of this Annual Report on Form 10-K. The Company's revolving credit facility has a floating interest rate, which exposes QEP to interest rate risk if QEP has borrowings outstanding. As of December 31, 2018 and 2017, QEP had $430.0 million and $89.0 million outstanding under its revolving credit facility, respectively. If interest rates were to increase or decrease 10% during the year ended December 31, 2018, at our average level of borrowing for those same periods, the Company's interest expense would increase or decrease by $2.0 million, or approximately 1% of total interest expense.

The remaining $2,099.3 million of the Company's debt is senior notes with fixed interest rates; therefore, it is not affected by interest rate movements. For more information regarding the Company's debt instruments, refer to Note 9 – Debt in Item 8 of Part II of this Annual Report on Form 10-K.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

All other schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or Notes thereto.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of QEP Resources, Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of QEP Resources, Inc. and its subsidiaries (the "Company") as of December 31, 2018 and 2017, and the related consolidated statements of operations, comprehensive income (loss), equity, and cash flows for each of the three years in the period ended December 31, 2018, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited 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 (COSO).

In our opinion, the consolidated financial statements referred to above 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 three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also 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 COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Assessment of Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (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 audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements 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. 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 audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

/s/ PricewaterhouseCoopers LLP
Denver, Colorado
February 20, 2019

We have served as the Company's auditor since 2012.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2018	2017	2016
REVENUES	(in millions, except per share amounts)		
Oil and condensate, gas and NGL sales	$1,871.3	$1,545.3	$1,269.7
Other revenues	12.5	15.0	6.2
Purchased oil and gas sales	48.8	62.6	101.2
Total Revenues	1,932.6	1,622.9	1,377.1
OPERATING EXPENSES			
Purchased oil and gas expense	51.0	64.3	105.5
Lease operating expense	263.1	294.8	224.7
Transportation and processing costs	117.6	245.3	289.2
Gathering and other expense	15.5	7.3	5.0
General and administrative	221.7	153.5	196.5
Production and property taxes	130.8	114.3	94.8
Depreciation, depletion and amortization	857.1	754.5	871.1
Exploration expenses	0.3	22.0	1.7
Impairment	1,560.9	78.9	1,194.3
Total Operating Expenses	3,218.0	1,734.9	2,982.8
Net gain (loss) from asset sales, inclusive of restructuring costs	25.0	213.5	5.0
OPERATING INCOME (LOSS)	(1,260.4)	101.5	(1,600.7)
Realized and unrealized gains (losses) on derivative contracts (Note 7)	90.4	24.5	(233.0)
Interest and other income (expense)	(9.6)	1.6	23.7
Loss from early extinguishment of debt	—	(32.7)	—
Interest expense	(149.4)	(137.8)	(143.2)
INCOME (LOSS) BEFORE INCOME TAXES	(1,329.0)	(42.9)	(1,953.2)
Income tax (provision) benefit	317.4	312.2	708.2
NET INCOME (LOSS)	$(1,011.6)	$269.3	$(1,245.0)
Earnings (loss) per common share			
Basic	$(4.25)	$1.12	$(5.62)
Diluted	$(4.25)	$1.12	$(5.62)
Weighted-average common shares outstanding			
Used in basic calculation	237.9	240.6	221.7
Used in diluted calculation	237.9	240.6	221.7

Refer to Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2018	2017	2016
	(in millions)		
Net income (loss)	$(1,011.6)	$269.3	$(1,245.0)
Other comprehensive income, net of tax:			
Future tax effective rate change[1]	—	(3.8)	—
Pension and other postretirement plans adjustments:			
Current period prior service cost[2]	(0.1)	2.4	—
Current period net actuarial (gain) loss[3]	(4.2)	5.8	(5.6)
Amortization of prior service cost[4]	0.4	0.5	0.8
Amortization of net actuarial (gain) loss[5]	0.6	0.3	0.5
Net curtailment and settlement cost incurred[6]	0.1	0.4	—
Other comprehensive income (loss)	(3.2)	5.6	(4.3)
Comprehensive income (loss)	$(1,014.8)	$274.9	$(1,249.3)

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(1) Refer to New Accounting Pronouncements in Note 1 – Summary of Significant Accounting Policies.

(2) Presented net of income tax benefit of $0.1 million for the year ended December 31, 2018 and net of income tax expense of $0.8 million for the year ended December 31, 2017.

(3) Presented net of income tax benefit of $1.3 million for the year ended December 31, 2018, net of income tax expense of $1.8 million for the year ended December 31, 2017 and net of income tax benefit of $3.3 million for the year ended December 31, 2016.

(4) Presented net of income tax expense of $0.1 million, $0.2 million and $0.5 million for the years ended December 31, 2018, 2017 and 2016, respectively.

(5) Presented net of income tax expense of $0.2 million, $0.1 million and $0.3 million for the years ended December 31, 2018, 2017 and 2016, respectively.

(6) Presented net of income tax expense $0.1 million for the year ended December 31, 2017.

Refer to Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2018	December 31, 2017
ASSETS	(in millions)	
Current Assets		
Cash and cash equivalents	$—	$ —
Accounts receivable, net	104.3	140.0
Income tax receivable	75.9	4.9
Fair value of derivative contracts	87.5	3.4
Prepaid expenses	12.7	10.1
Other current assets	0.2	3.6
Total Current Assets	280.6	162.0
Property, Plant and Equipment (successful efforts method for oil and gas properties)		
Proved properties	9,096.9	8,081.0
Unproved properties	705.5	1,028.5
Gathering and other	167.7	111.0
Materials and supplies	29.9	24.8
Total Property, Plant and Equipment	10,000.0	9,245.3
Less Accumulated Depreciation, Depletion and Amortization		
Exploration and production	4,882.4	3,315.2
Gathering and other	58.1	63.4
Total Accumulated Depreciation, Depletion and Amortization	4,940.5	3,378.6
Net Property, Plant and Equipment	5,059.5	5,866.7
Fair value of derivative contracts	35.4	0.1
Other noncurrent assets	49.6	45.1
Noncurrent assets held for sale	692.7	1,320.9
TOTAL ASSETS	$6,117.8	$ 7,394.8
LIABILITIES AND EQUITY		
Current Liabilities		
Checks outstanding in excess of cash balances	$14.6	$ 44.0
Accounts payable and accrued expenses	258.1	360.1
Production and property taxes	24.1	31.6
Interest payable	32.4	26.0
Fair value of derivative contracts	—	103.6
Asset retirement obligations	5.1	2.8
Total Current Liabilities	334.3	568.1
Long-term debt	2,507.1	2,160.8
Deferred income taxes	269.2	518.0
Asset retirement obligations	96.9	104.1
Fair value of derivative contracts	0.7	34.8
Other long-term liabilities	97.4	101.9
Other long-term liabilities held for sale	61.3	109.2
Commitments and Contingencies (Note 10)		
EQUITY		
Common stock - par value $0.01 per share; 500.0 million shares authorized; 239.8 million and 243.0 million shares issued, respectively	2.4	2.4
Treasury stock - 3.1 million and 2.0 million shares, respectively	(45.6)	(34.2)

Additional paid-in capital	1,431.9	1,398.2
Retained earnings	1,376.5	2,442.6
Accumulated other comprehensive income (loss)	(14.3)	(11.1)
Total Common Shareholders' Equity	2,750.9	3,797.9
TOTAL LIABILITIES AND EQUITY	$6,117.8	$ 7,394.8

Refer to Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF EQUITY

	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income(Loss)	Total
	Shares	Amount	Shares	Amount				
	(in millions)							
Balance at December 31, 2015	177.3	$ 1.8	(0.5)	$(14.6)	$ 554.8	$3,418.3	$ (12.4)	$3,947.9
Net income (loss)	—	—	—	—	—	(1,245.0)	—	(1,245.0)
Equity issuance, net of offering costs	61.0	0.6	—	—	780.8	—	—	781.4
Share-based compensation	2.4	—	(0.6)	(8.3)	31.0	—	—	22.7
Change in pension and postretirement liability, net of tax	—	—	—	—	—	—	(4.3)	(4.3)
Balance at December 31, 2016	240.7	2.4	(1.1)	(22.9)	1,366.6	2,173.3	(16.7)	3,502.7
Net income (loss)	—	—	—	—	—	269.3	—	269.3
Share-based compensation	2.3	—	(0.9)	(11.3)	31.6	—	—	20.3
Change in pension and postretirement liability, net of tax	—	—	—	—	—	—	5.6	5.6
Balance at December 31, 2017	243.0	2.4	(2.0)	(34.2)	1,398.2	2,442.6	(11.1)	3,797.9
Net income (loss)	—	—	—	—	—	(1,011.6)	—	(1,011.6)
Reclassification related to ASU 2018-02 adoption	—	—	—	—	—	3.8	(3.8)	—
Common stock repurchased and retired	(6.2)	(0.1)	—	—	—	(58.3)	—	(58.4)
Share-based compensation	3.0	0.1	(1.1)	(11.4)	33.7	—	—	22.4
Change in pension and postretirement liability, net of tax	—	—	—	—	—	—	0.6	0.6
Balance at December 31, 2018	239.8	$ 2.4	(3.1)	$(45.6)	$ 1,431.9	$1,376.5	$ (14.3)	$2,750.9

Refer to Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2018	2017	2016
OPERATING ACTIVITIES	(in millions)		
Net income (loss)	$(1,011.6)	$269.3	$(1,245.0)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	857.1	754.5	871.1
Deferred income taxes	(247.6)	(314.8)	(651.3)
Impairment	1,560.9	78.9	1,194.3
Dry hole exploratory well expense	—	21.3	—
Share-based compensation	39.1	22.4	35.6
Amortization of debt issuance costs and discounts	5.4	6.2	6.4
Bargain purchase gain from acquisitions	—	0.4	(22.6)
Net (gain) loss from asset sales, inclusive of restructuring costs	(25.0)	(213.5)	(5.0)
Loss from early extinguishment of debt	—	32.7	—
Unrealized (gains) losses on marketable securities	1.2	(2.9)	(1.4)
Unrealized (gains) losses on derivative contracts	(248.5)	(40.0)	367.0
Other non-cash activity	—	(9.4)	—
Changes in operating assets and liabilities			
Accounts receivable	33.7	(2.0)	95.3
Prepaid expenses	(2.0)	(1.3)	18.7
Accounts payable and accrued expenses	(74.2)	3.5	(50.3)
Income taxes receivable	(71.0)	13.7	68.7
Other	(1.3)	(18.8)	(14.3)
Net Cash Provided by (Used in) Operating Activities	816.2	600.2	667.2
INVESTING ACTIVITIES			
Property acquisitions	(65.6)	(815.2)	(639.0)
Property, plant and equipment, including exploratory well expense	(1,234.1)	(1,159.6)	(569.1)
Proceeds from disposition of assets	243.6	806.8	29.0
Net Cash Provided by (Used in) Investing Activities	(1,056.1)	(1,168.0)	(1,179.1)
FINANCING ACTIVITIES			
Checks outstanding in excess of cash balances	(29.5)	31.7	(17.5)
Long-term debt issued	—	500.0	—
Long-term debt issuance costs paid	(0.1)	(14.4)	—
Long-term debt extinguishment costs paid	—	(28.1)	—
Long-term debt repaid	—	(445.6)	(176.8)
Proceeds from credit facility	3,608.0	492.0	—
Repayments of credit facility	(3,267.0)	(403.0)	—
Common stock repurchased and retired	(58.4)	—	—
Treasury stock repurchases	(8.7)	(6.8)	(4.1)
Other capital contributions	0.3	—	—
Proceeds from issuance of common stock, net	—	—	781.4
Excess tax (provision) benefit on share-based compensation	—	—	0.1
Net Cash Provided by (Used in) Financing Activities	244.6	125.8	583.1
Change in cash, cash equivalents and restricted cash(1)	4.7	(442.0)	71.2
Beginning cash, cash equivalents and restricted cash(1)	23.4	465.4	394.2
Ending cash, cash equivalents and restricted cash(1)	$28.1	$23.4	$465.4

[1] Refer to New Accounting Pronouncements in Note 1 – Summary of Significant Accounting Policies.

Refer to Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
NOTES ACCOMPANYING THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 – Summary of Significant Accounting Policies

Nature of Business

QEP Resources, Inc. (QEP or the Company) is an independent crude oil and natural gas exploration and production company with operations in two regions of the United States: the Southern Region (primarily in Texas) and the Northern Region (primarily in North Dakota). During 2018, the Company sold its Uinta Basin assets and entered into purchase and sale agreements to divest substantially all of its Haynesville/Cotton Valley assets in Louisiana and its Williston Basin assets in North Dakota. In January, the Company closed the sale of its Haynesville/Cotton Valley assets. In February 2019, the Company agreed with the buyer to terminate the purchase and sale agreement related to its Williston Basin assets. Unless otherwise specified or the context otherwise requires, all references to "QEP" or the "Company" are to QEP Resources, Inc. and its subsidiaries on a consolidated basis. QEP's corporate headquarters are located in Denver, Colorado and shares of QEP's common stock trade on the New York Stock Exchange (NYSE) under the ticker symbol "QEP".

Principles of Consolidation

The Consolidated Financial Statements contain the accounts of QEP and its majority-owned or controlled subsidiaries. The Consolidated Financial Statements were prepared in accordance with GAAP and with the instructions for annual reports on Form 10-K and Regulation S-X. All significant intercompany accounts and transactions have been eliminated in consolidation.

All dollar and share amounts in this Annual Report on Form 10-K are in millions, except per share information and where otherwise noted.

Business Segments

QEP conducted a segment analysis in accordance with Accounting Standards Codification (ASC) Topic 280, Segment Reporting, and determined that QEP has one reportable segment.

Reclassifications

Certain prior period balances on the Consolidated Balance Sheets and Consolidated Statements of Cash Flows have been reclassified due to noncurrent held for sale classification related to the divestiture of the Uinta Basin assets and Haynesville/Cotton Valley assets and to conform to the current year presentation. Such reclassifications had no effect on the Company's net income (loss), earnings (loss) per share or retained earnings previously reported.

Use of Estimates

The preparation of the Consolidated Financial Statements and Notes in conformity with GAAP requires that management formulate estimates and assumptions that affect revenues, expenses, assets, liabilities and the disclosure of contingent assets and liabilities. A significant item that requires management's estimates and assumptions is the estimate of proved oil and condensate, gas and NGL reserves, which are used in the calculation of depreciation, depletion and amortization rates of its oil and gas properties, impairment of proved properties and asset retirement obligations. Changes in estimated quantities of its reserves could impact the Company's reported financial results as well as disclosures regarding the quantities and value of proved oil and gas reserves. Other items subject to estimates and assumptions include the carrying amount of property, plant and equipment, assigning fair value and allocating purchase price in connection with business combinations, valuation allowances for receivables, income taxes, valuation of derivatives instruments, contingencies, accrued liabilities, accrued revenue and related receivables and obligations related to employee benefits, among others. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Risks and Uncertainties

The Company's revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for oil, gas and NGL, which are affected by many factors outside of QEP's control, including changes in market supply and demand. Changes in market supply and demand are impacted by weather conditions, pipeline capacity constraints, inventory storage levels, basis differentials, export capacity, strength of the U.S. dollar and other factors. Field-level prices received for QEP's oil and condensate and gas production have historically been volatile and may be subject to significant fluctuations in the future. The Company's derivative contracts serve to mitigate in part the effect of this price volatility on the Company's cash flows, and the Company has derivative contracts in place for a portion of its expected future oil and condensate and gas production. Refer to Note 7 – Derivative Contracts for the Company's open oil and gas commodity derivative contracts.

Revenue Recognition

QEP recognizes revenue from the sales of oil and condensate, gas and NGL in the period that the performance obligations are satisfied. QEP's performance obligations are satisfied when the customer obtains control of product, when we have no further obligations to perform related to the sale, when the transaction price has been determined and when collectability is probable. The sales of oil and condensate, gas and NGL are made under contracts with customers, which typically include consideration that is based on pricing tied to local indices and volumes delivered in the current month. Reported revenues include estimates for the two most recent months using published commodity price indexes and volumes supplied by field operators. Performance obligations under our contracts with customers are typically satisfied at a point in time through monthly delivery of oil and condensate, gas and/or NGL. Our contracts with customers typically require payment for oil and condensate, gas and NGL sales within 30 days following the calendar month of delivery.

QEP's oil is typically sold at specific delivery points under contract terms that are common in our industry. QEP's gas and NGL are also sold under contract types that are common in our industry; however, under these contracts, the gas and its components, including NGL, may be sold to a single purchaser or the residue gas and NGL may be sold to separate purchasers. Regardless of the contract type, the terms of these contracts compensate the Company for the value of the residue gas and NGL constituent components at market prices for each product. QEP also purchases and resells oil and gas primarily to mitigate losses on unutilized capacity related to firm transportation commitments and storage activities. QEP recognizes revenue from these resale activities in the period that the performance obligations are satisfied.

Cash, Cash Equivalents and Restricted Cash

Cash equivalents consist principally of highly liquid investments in securities with original maturities of three months or less made through commercial bank accounts that result in available funds the next business day. Restricted cash are funds that are legally or contractually reserved for a specific purpose and therefore not available for immediate or general business use.

The following table provides a reconciliation of cash, cash equivalents and restricted cash reported within the Consolidated Balance Sheets to the amounts shown in the Consolidated Statements of Cash Flows:

	December 31,	
	2018	2017
	(in millions)	
Cash and cash equivalents	$—	$—
Restricted cash[(1)]	28.1	23.4

Total cash, cash equivalents and restricted cash shown in the Consolidated Statements of Cash Flows	$28.1	$23.4

(1) As of December 31, 2018 and 2017, the restricted cash balance related to cash deposited into an escrow account for a title dispute between outside parties in the Williston Basin, and the restricted cash balance is recorded within "Other noncurrent assets" on the Consolidated Balance Sheets.

Supplemental cash flow information is shown in the table below:

	Year Ended December 31,		
	2018	2017	2016
Supplemental Disclosures:	(in millions)		
Cash paid for interest, net of capitalized interest	$136.9	$134.9	$139.1
Cash paid (refund received) for income taxes, net	$0.8	$(0.3)	$(123.5)
Non-cash Investing Activities:			
Change in capital expenditure accrual balance	$(57.4)	$60.2	$(32.8)

Accounts Receivable

Accounts receivable consists mainly of receivables from oil and gas purchasers and joint interest owners on properties the Company operates. For receivables from joint interest owners, the Company has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Generally, the Company's oil and gas receivables are collected and bad debts are minimal. However, if commodity prices remain low for an extended period of time, the Company could incur increased levels of bad debt expense. Bad debt expense associated with accounts receivable for the years ended December 31, 2018 and 2016 was $0.6 million and $1.8 million, respectively. Recovery of bad debt associated with accounts receivable for the year ended December 31, 2017 was $1.0 million. Bad debt expense or recovery is included in "General and administrative" expense on the Consolidated Statements of Operations. The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectability. The allowance for bad debt expenses was $1.3 million at December 31, 2018, and $1.6 million at December 31, 2017.

Property, Plant and Equipment

Property, plant and equipment balances are stated at historical cost. Material and supplies inventories are valued at the lower of cost or net realizable value. Maintenance and repair costs are expensed as incurred. Significant accounting policies for our property, plant and equipment are as follows:

Successful Efforts Accounting for Oil and Gas Operations
The Company follows the successful efforts method of accounting for oil and gas property acquisitions, exploration, development and production activities. Under this method, the acquisition costs of proved and unproved properties, successful exploratory wells and development wells are capitalized. Other exploration costs, including geological and geophysical costs, delay rentals and administrative costs associated with unproved property and unsuccessful exploratory well costs are expensed. Costs to operate and maintain wells and field equipment are expensed as incurred. A gain or loss is generally recognized only when an entire field is sold or abandoned, or if the unit-of-production depreciation, depletion and amortization rate would be significantly affected. Capitalized costs of unproved properties are reclassified to proved property when related proved reserves are determined or charged against the impairment allowance when abandoned.

Depreciation, Depletion and Amortization (DD&A)
Capitalized proved leasehold costs are depleted on a field-by-field basis using the unit-of-production method and the estimated total proved oil and gas reserves. Capitalized costs of exploratory wells that have found proved oil and gas reserves and capitalized development costs are depreciated using the unit-of-production method based on estimated proved developed reserves for a successful effort field. The Company capitalizes an estimate of the fair value of future abandonment costs.

DD&A for the Company's remaining properties is generally based upon rates that will systematically charge the costs of assets against income over the estimated useful lives of those assets using the straight-line method. The estimated useful lives of those assets depreciated under the straight-line basis generally range as follows:

Buildings	10 to 30 years
Leasehold improvements	3 to 10 years
Service, transportation and field service equipment	3 to 7 years
Furniture and office equipment	3 to 7 years

Impairment of Long-Lived Assets
Proved oil and gas properties are evaluated on a field-by-field basis for potential impairment. Other properties are evaluated on a specific asset basis or in groups of similar assets, as applicable. Impairment is indicated when a triggering event occurs and/or the sum of the estimated undiscounted future net cash flows of an evaluated asset is less than the asset's carrying value. Triggering events could include, but are not limited to, a reduction of oil and condensate, gas and NGL reserves caused by mechanical problems, faster-than-expected decline of production, lease ownership issues, potential disposition of assets and declines in oil, gas and NGL prices. If impairment is indicated, fair value is estimated using a discounted cash flow approach. Cash flow estimates require forecasts and assumptions for many years into the future for a variety of factors, including commodity prices, operating costs and estimates of proved, probable and possible reserves. The signing of a purchase and sale agreement could also cause the Company to recognize an impairment of proved properties. For assets subject to a purchase and sale agreement, the terms of the purchase and sale agreement are used as an indicator of fair value. If a range is estimated for the amount of possible future cash flows, the fair value of property is measured utilizing a probability-weighted approach whereas the likelihood of possible outcomes is taken into consideration. Specific to the Planned Williston Basin Divestiture, the Company obtained a Black-Scholes-Merton estimate of the value of the contractual rights to receive up to 5.8 million shares of the buyer's common stock at December 31, 2018. Cash flow estimates relating to future cash flows from probable and possible reserves are reduced by additional risk-weighting factors.

Unproved properties are evaluated on a specific asset basis or in groups of similar assets, as applicable. The Company performs periodic assessments of unproved oil and gas properties for impairment and recognizes a loss at the time of impairment. In determining whether an unproved property is impaired, the Company considers numerous factors including, but not limited to, current development and exploration drilling plans, favorable or unfavorable exploration activity on adjacent leaseholds, in-house geologists' evaluation of the lease, future reserve cash flows and the remaining lease term.

During the year ended December 31, 2018, QEP recorded impairment charges of $1,560.9 million, of which $1,559.3 million related to proved and unproved properties impairment as a result of signing purchase and sale agreements for the divestitures of the Williston Basin and Uinta Basin assets. The Williston Basin assets were impaired in the fourth quarter utilizing a probability-weighted assets held and use model, and the Uinta Basin assets were impaired in the second quarter utilizing an assets held for sale model.

During the year ended December 31, 2017, QEP recorded impairment charges of $78.9 million, of which $38.1 million, primarily in the Other Northern area, was related to proved properties due to lower future gas prices, $29.0 million was primarily related to unproved leasehold acreage in the Central Basin Platform (refer to Note 4 – Capitalized Exploratory Well Costs for more information), $6.5 million was related to the impairment of an underground gas storage facility and $5.3 million was related to the impairment of goodwill.

During the year ended December 31, 2016, QEP recorded impairment charges of $1,194.3 million, of which $1,172.7 million was related to proved properties due to lower future oil and gas prices, $17.9 million was related to expiring leaseholds on unproved properties and $3.7 million was related to the impairment of goodwill. Of the $1,172.7 million impairment of proved properties, $1,164.0 million was related to Pinedale properties, $4.7 million related to Uinta Basin properties, $3.4 million related to the Other Northern area and $0.6 million related to QEP's remaining Other Southern properties.

Asset Retirement Obligations (ARO)
QEP is obligated to fund the costs of disposing of long-lived assets upon their abandonment. The Company's ARO liability applies primarily to abandonment costs associated with oil and gas wells and certain other properties. ARO associated with the retirement of tangible long-lived assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived assets in the period incurred. The cost of the tangible asset, including the asset

retirement costs, is depreciated over the useful life of the asset. ARO are recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligations discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value. If estimated future costs of ARO change, an adjustment is recorded to both the ARO liability and the long-lived asset. Revisions to estimated ARO can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment. Refer to Note 5 – Asset Retirement Obligations for more information.

Goodwill

Goodwill represents the excess of the amount paid over the fair value of assets acquired in a business combination and is not subject to amortization. QEP performs an annual goodwill impairment test by comparing the fair value of a reporting unit with its carry amount, with an impairment charge being recognized for the amount by which the carrying amount exceeds the reporting unit's fair value. QEP determines the fair value of its reporting units in which goodwill is allocated using the income approach in which the fair value is estimated based on the value of expected future cash flows. Key assumptions used in the cash flow model include estimated quantities of oil and condensate, gas and NGL reserves, including both proved reserves and risk-adjusted unproved reserves, and including probable and possible reserves; estimates of market prices considering forward commodity price curves as of the measurement date; estimates of revenue and operating costs over a multi-year period; and estimates of capital costs.

During the years ended December 31, 2017 and 2016, QEP recorded $5.3 million and $3.7 million, respectively, of goodwill. During the years ended December 31, 2017 and 2016, QEP tested goodwill for impairment, which resulted in a full write down of $5.3 million and $3.7 million, respectively.

Litigation and Other Contingencies

The Company is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business. In each reporting period, the Company assesses these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in its Consolidated Financial Statements. The amount of ultimate loss may differ from these estimates. In accordance with ASC 450, Contingencies, an accrual is recorded for a material loss contingency when its occurrence is probable and damages are reasonably estimable based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes. Refer to Note 10 – Commitments and Contingencies for more information.

QEP accrues material losses associated with environmental obligations when such losses are probable and can be reasonably estimated. Accruals for estimated environmental losses are recognized no later than at the time the remediation feasibility study, or the evaluation of response options, is complete. These accruals are adjusted as more information becomes available or as circumstances change. Future environmental expenditures are not discounted to their present value. Recoveries of environmental costs from other parties are recorded separately as assets at their undiscounted value when receipt of such recoveries is probable.

Derivative Contracts

QEP has established policies and procedures for managing commodity price volatility through the use of derivative instruments. QEP uses commodity derivative instruments, typically fixed-price swaps and costless collars to realize a known price or price range for a specific volume of production delivered into a regional sales point. QEP's commodity derivative instruments do not require the physical delivery of oil or gas between the parties at settlement. All transactions are settled in cash with one party paying the other for the net difference in prices, multiplied by the contract volume, for the settlement period. QEP does not engage in speculative hedging transactions, nor does it buy and sell energy contracts with the objective of generating profits on short-term differences in price. Additionally, QEP does not currently have any commodity derivative transactions that have margin requirements or collateral provisions that would require payments prior to the scheduled settlement dates.

These derivative contracts are recorded in "Realized and unrealized gains (losses) on derivative contracts" on the Consolidated Statements of Operations in the month of settlement and are also marked-to-market monthly. Refer to Note 7 – Derivative Contracts for more information.

Credit Risk

Management believes that its credit review procedures, loss reserves, cash deposits and investments, and collection procedures have adequately provided for usual and customary credit-related losses. Exposure to credit risk may be affected by extended periods of low commodity prices, as well as the concentration of customers in certain regions due to changes in economic or other conditions. Customers include commercial and industrial enterprises and financial institutions that may react differently to changing conditions.

The Company utilizes various processes to monitor and evaluate its credit risk exposure, which include closely monitoring current market conditions and counterparty credit fundamentals, including public credit ratings, where available. Credit exposure is controlled through credit approvals and limits based on counterparty credit fundamentals. Credit exposure is aggregated across all lines of business, including derivatives, physical exposure and short-term cash investments. To further manage the level of credit risk, the Company requests credit support and, in some cases, requests parental guarantees, letters of credit or prepayment from companies with perceived higher credit risk. Loss reserves are periodically reviewed for adequacy and, if needed, are established on a specific case basis. The Company also has master-netting agreements with some counterparties that allow the offsetting of receivables and payables in a default situation.

The Company enters into International Swap Dealers Association Master Agreements (ISDA Agreements) with each of its derivative counterparties prior to executing derivative contracts. The terms of the ISDA Agreements provide the Company and the counterparties with rights of set-off upon the occurrence of defined acts of default by either the Company or counterparty to a derivative contract. The Company routinely monitors and manages its exposure to counterparty risk related to derivative contracts by requiring specific minimum credit standards for all counterparties, actively monitoring counterparties public credit ratings, and avoiding concentration of credit exposure by transacting with multiple counterparties. The Company's commodity derivative contract counterparties are typically financial institutions and energy trading firms with investment-grade credit ratings.

The Company's five largest customers accounted for 49%, 59%, and 48% of QEP's revenues for the years ended December 31, 2018, 2017 and 2016, respectively. The following table presents the percentages by customer that accounted for 10% or more of QEP's total revenues.

Year Ended December 31, 2018	
Occidental Energy Marketing	16%
Plains Marketing LP	12%
Year Ended December 31, 2017	
Shell Trading Company	14%
Occidental Energy Marketing	13%
Andeavor Logistics LP	13%
BP Energy Company	10%
Plains Marketing LP	10%
Year Ended December 31, 2016	
Shell Trading Company	14%
BP Energy Company	10%
Valero Marketing & Supply Company	10%

Income Taxes

The amount of income taxes recorded by QEP requires interpretations of complex rules and regulations of various tax jurisdictions throughout the United States. QEP has recognized deferred tax assets and liabilities for temporary differences, operating losses and tax credit carryforwards. Deferred income taxes are provided for the temporary differences arising between the book and tax carrying amounts of assets and liabilities. These differences create taxable or tax-deductible amounts for future periods.

ASC 740, Income Taxes, specifies the accounting for uncertainty in income taxes by prescribing a minimum recognition threshold for a tax position to be reflected in the financial statements. If recognized, the tax benefit is measured as the largest amount of tax benefit that is more-likely-than-not to be realized upon ultimate settlement. Management has considered the amounts and the probabilities of the outcomes that could be realized upon ultimate settlement and believes that it is more-likely-than-not that the Company's recorded income tax benefits will be fully realized, except as noted below. As of December 31, 2018, the Company had a valuation allowance of $82.3 million against the state net operating loss deferred tax asset mainly because management does not forecast future income in Oklahoma, Utah and Louisiana to offset net operating losses before they expire. All federal income tax returns prior to 2018 have been examined by the Internal Revenue Service and are closed. Income tax returns for 2018 have not yet been filed. Most state tax returns for 2015 and subsequent years remain subject to examination.

The benefits of uncertain tax positions taken or expected to be taken on income tax returns is recognized in the consolidated financial statements at the largest amount that is more-likely-than-not to be sustained upon examination by the relevant taxing authorities. Our policy is to recognize any interest earned on income tax refunds in "Interest and other income (expense)" on the Consolidated Statements of Operations, any interest expense related to uncertain tax positions in "Interest expense" on the Consolidated Statements of Operations and to recognize any penalties related to uncertain tax positions in "General and administrative" expense on the Consolidated Statements of Operations. As of December 31, 2018 and 2017, QEP had $19.0 million of unrecognized tax benefits related to uncertain tax positions for asset sales that occurred in 2014, which was included within "Other long-term liabilities" on the Consolidated Balance Sheets. During the years ended December 31, 2018, 2017 and 2016, the Company incurred $0.7 million of estimated interest expense related to uncertain tax positions. During the year ended December 31, 2016, the Company incurred $0.6 million of estimated penalties related to uncertain tax positions.

In December 2017, the Tax Cuts and Jobs Act (H.R.1) (Tax Legislation) was signed into law, which resulted in significant changes to U.S. federal income tax law. QEP expects that these changes will positively impact QEP's future after-tax earnings in the U.S., primarily due to the lower federal statutory tax rate of 21% compared to 35%. The impact of the Tax Legislation may differ from the statements above due to, among other things, changes in interpretations and assumptions the Company has made and actions the Company may take as a result of the Tax Legislation. Additionally, guidance issued by the relevant regulatory authorities regarding the Tax Legislation may materially impact QEP's financial statements. As additional guidance to the Tax Legislation is published in the form of Treasury Regulations and other IRS communications, the Company will monitor, assess, and determine the impact of these communications on the Company's consolidated financial statements and operations. In addition to the Tax Legislation, QEP is continuing to monitor proposed regulations regarding the 163(j) Limitation on Deduction for Business Interest Expense, which when finalized, could require QEP to re-characterize the Company's deferred tax assets, resulting in changes in QEP's income tax disclosures. QEP expects the impact to the Company's results of operations to be immaterial.

Treasury Stock

We record treasury stock purchases at cost, which includes incremental direct transaction costs. Amounts are recorded as a reduction in shareholders' equity in the Consolidated Balance Sheets. QEP acquires treasury stock from stock forfeitures and withholdings and uses the acquired treasury stock for stock option exercises and certain stock grants to employees. Refer to Note 11 – Share-Based Compensation for more information.

Earnings (Loss) Per Share

Basic earnings (loss) per share (EPS) are computed by dividing net income (loss) by the weighted-average number of common shares outstanding during the reporting period. Diluted EPS includes the potential increase in the number of outstanding shares that could result from the exercise of in-the-money stock options. QEP's unvested restricted share awards are included in weighted-average basic common shares outstanding because, once the shares are granted, the restricted share awards are considered issued and outstanding, the historical forfeiture rate is minimal and the restricted share awards are eligible to receive dividends.

Unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are considered participating securities and are included in the computation of earnings (loss) per share pursuant to the two-class method. The Company's unvested restricted share awards contain non-forfeitable dividend rights and participate equally with common stock with respect to dividends issued or declared. However, the Company's unvested restricted share awards do not have a contractual obligation to share in losses of the Company. The Company's unexercised stock options do not contain rights to dividends. Under the two-class method, the earnings used to determine basic earnings (loss) per common share are reduced by an amount allocated to participating securities. When the Company records a net loss, none of the loss is allocated to the participating securities since the securities are not obligated to share in Company losses. Use of the two-class method has an insignificant impact on the calculation of basic and diluted earnings (loss) per common share. For the years ended December 31, 2018 and 2017, there were no anti-dilutive shares. For the year ended December 31, 2016, there were 0.1 million shares not included in diluted common shares outstanding as they were anti-dilutive due to QEP's net loss from continuing operations.

The following is a reconciliation of the components of basic and diluted shares used in the EPS calculation:

	December 31,		
	2018	2017	2016
	(in millions)		
Weighted-average basic common shares outstanding	237.9	240.6	221.7
Potential number of shares issuable upon exercise of in-the-money stock options under the Long-Term Stock Incentive Plan	—	—	—
Average diluted common shares outstanding	237.9	240.6	221.7

Share-Based Compensation

QEP issues stock options, restricted share awards and restricted share units to certain officers, employees and non-employee directors under its 2018 Long-Term Incentive Plan (LTIP). QEP uses the Black-Scholes-Merton mathematical model to estimate the fair value of stock options for accounting purposes. The grant date fair value for restricted share awards is determined based on the closing bid price of the Company's common stock on the grant date. Share-based compensation cost for restricted share units is equal to its fair value as of the end of the period and is classified as a liability. QEP uses an accelerated method in recognizing share-based compensation costs for stock options and restricted share awards with graded-vesting periods. Stock options held by employees generally vest in three equal, annual installments and primarily have a term of seven years. Restricted share awards and restricted share units vest in equal installments over a specified number of years after the grant date with the majority vesting in three years. Non-vested restricted share awards have voting and dividend rights; however, sale or transfer is restricted. Employees may elect to defer their grants of restricted share awards and these deferred awards are designated as restricted share units. Restricted share units vest over a three-year period and are deferred into the Company's nonqualified unfunded deferred compensation plan at the time of vesting. The Company also awards performance share units under its Cash Incentive Plan (CIP) that are generally paid out in cash depending upon the Company's total shareholder return compared to a group of its peers over a three-year period. Share-based compensation cost for the performance share units is equal to its fair value as of the end of the period and is classified as a liability. Refer to Note 11 – Share-Based Compensation for more information.

Pension and Other Postretirement Benefits

QEP maintains closed, defined-benefit pension and other postretirement benefit plans, including both a qualified and a supplemental plan. QEP also provides certain health care and life insurance benefits for certain retired QEP employees. Determination of the benefit obligations for QEP's defined-benefit pension and other postretirement benefit plans impacts the recorded amounts for such obligations on the Consolidated Balance Sheets and the amount of benefit expense recorded to the Consolidated Statements of Operations.

QEP measures pension plan assets at fair value. Defined-benefit plan obligations and costs are actuarially determined, incorporating the use of various assumptions. Critical assumptions for pension and other postretirement benefit plans include the discount rate, the expected rate of return on plan assets (for funded pension plans) and the rate of future compensation increases. Other assumptions involve demographic factors such as retirement, mortality and turnover. QEP evaluates and updates its actuarial assumptions at least annually. QEP recognizes a pension curtailment immediately when there is a significant reduction in, or an elimination of, defined-benefit accruals for present employees' future services. Refer to Note 12 – Employee Benefits for more information.

Comprehensive Income (Loss)

Comprehensive income (loss) is the sum of net income (loss) as reported in the Consolidated Statements of Operations and changes in the components of other comprehensive income (loss). Other comprehensive income (loss) includes certain items that are recorded directly to equity and classified as accumulated other comprehensive income (AOCI), which includes changes in the underfunded portion of the Company's defined-benefit pension and other postretirement benefits plans and changes in deferred income taxes on such amounts. These transactions do not represent the culmination of the earnings process but result from periodically adjusting historical balances to fair value.

Recent Accounting Developments

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers (Topic 606), which seeks to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries and across capital markets. The FASB subsequently issued various ASUs which deferred the effective date of ASU No. 2014-09 and provided additional implementation guidance, including industry specific guidance. The revenue standard contains principles that an entity will apply to determine the measurement of revenue and timing of when revenue is recognized. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. In addition, new and enhanced disclosures are required. The amendment was effective for public companies prospectively for reporting periods beginning on or after December 15, 2017, and early adoption was permitted for periods beginning on or after December 15, 2016. The two permitted transition methods under the new standard are the full retrospective method, in which case the standard would be applied to each prior reporting period presented, or the modified retrospective method, in which case the cumulative effect of applying the standard would be recognized at the date of initial application. The Company selected the modified retrospective method and adopted this standard in the first quarter of 2018. Refer to Note 2 – Revenue for more information.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which requires lessees to recognize the lease assets and lease liabilities classified as operating leases on the balance sheet and disclose key quantitative and qualitative information about leasing arrangements. The FASB subsequently issued various ASUs which provided additional implementation guidance. ASU 2016-02 and its amendments will be effective for reporting periods beginning after December 15, 2018, and early adoption is permitted. The Company will adopt ASU 2016-02 on January 1, 2019, using the modified retrospective transition approach with a cumulative effect adjustment as of the date of adoption. This standard does not apply to leases to explore for or use minerals, oil or natural gas resources, including the right to explore for those natural resources. This new guidance will increase other assets and other liabilities recorded on the Company's Consolidated Balance Sheets due to an increase in right of use assets and corresponding lease liabilities primarily related to leases for office buildings, compressors and generators. Also, any deferred rent balances as of December 31, 2018 will be reclassified to the right of use asset. The new guidance will not have a significant impact on the income statement.

In October 2016, the FASB issued ASU No. 2016-16, Accounting for Income Taxes: Intra-Entity Asset Transfers of Assets Other than Inventory, which intends to reduce the complexity in accounting standards related to intra-entity asset transfers by requiring a reporting entity to recognize the tax effects from the sale of assets when a transfer occurs, even though the pre-tax effects of the transaction are eliminated in consolidation. This amendment was effective retrospectively for reporting periods beginning after December 15, 2017, and early adoption was permitted. The Company adopted this standard in the first quarter of 2018 and the adoption did not have a material impact on the Company's Consolidated Financial Statements.

In November 2016, the FASB issued ASU No. 2016-18, Statement of Cash Flows (Topic 230): Restricted cash, which intends to clarify how entities should present restricted cash and restricted cash equivalents in the statement of cash flows. This amendment was effective retrospectively for reporting periods after December 15, 2017, and early adoption was permitted. The Company adopted this standard in the first quarter of 2018 and the adoption did not have a material impact on the Company's Consolidated Statements of Cash Flows.

In February 2018, the FASB issued ASU No. 2018-02, Income statement – Reporting comprehensive income (Topic 220) – Reclassification of certain tax effects from accumulated other comprehensive income, which allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Legislation. This amendment is effective for reporting periods beginning after December 15, 2018, and early adoption was permitted. The Company early adopted this standard in the fourth quarter of 2018 and the adoption did not have a material impact on the Company's Consolidated Financial Statements.

In March 2018, the FASB issued ASU No. 2018-05, Income Taxes (Topic 740) – Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118, which amends guidance on certain investments and income taxes as a result of the Tax Legislation. The amendment was effective upon issuance. The adoption did not have a material impact on the Company's Consolidated Financial Statements.

In August 2018, the FASB issued ASU No. 2018-13, Fair value measurement (Topic 820) – Disclosure framework – Changes to the disclosure requirements for fair value measurement, which modifies the disclosure requirements on fair value measurements in Topic 820. The amendment will be effective for reporting periods beginning after December 15, 2019, and early adoption is permitted. The Company is currently assessing the impact of the ASU on the Company's Consolidated Financial Statements.

In August 2018, the FASB issued ASU No. 2018-14, Compensation – retirement benefits – Defined benefit plans – General (Subtopic 715-20) – Disclosure Framework – Changes to the disclosure requirements for defined benefit plans, which modifies disclosure requirements on defined benefit plans in Topic 715. The amendment will be effective for reporting periods beginning after December 15, 2020, and early adoption is permitted. The Company is currently assessing the impact of the ASU on the Company's Consolidated Financial Statements.

Note 2 – Revenue

Adoption of ASC Topic 606, Revenue from Contracts with Customers

On January 1, 2018, QEP adopted ASC Topic 606, Revenue from Contracts with Customers, using the modified retrospective approach, which was applied to those contracts which were not completed as of January 1, 2018. Results for reporting periods beginning January 1, 2018, are presented in accordance with ASC Topic 606, while prior period amounts are reported in accordance with ASC Topic 605, Revenue Recognition.

In accordance with ASC Topic 606, QEP now records transportation and processing costs that are incurred after control of its product has transferred to the customer as a reduction of "Oil and condensate, gas and NGL sales" on the Consolidated Statements of Operations. Prior to the adoption of ASC Topic 606, these transportation and processing costs were recorded as an expense within "Transportation and processing costs" on the Consolidated Statements of Operations. There was no impact to net income (loss) or opening retained earnings as a result of adopting ASC Topic 606.

The following table presents the impact to the Consolidated Statements of Operations as a result of adopting ASC Topic 606.

	Year Ended December 31, 2018		
	As Reported	ASC Topic 606 Adjustments	As Adjusted[(1)]
REVENUES	(in millions, except per share amounts)		
Oil and condensate, gas and NGL sales	$ 1,871.3	$ 55.0	$ 1,926.3
Other revenues	12.5	—	12.5
Purchased oil and gas sales	48.8	—	48.8
Total Revenues	1,932.6	55.0	1,987.6
OPERATING EXPENSES			
Purchased oil and gas expense	51.0	—	51.0
Lease operating expense	263.1	—	263.1
Transportation and processing costs	117.6	55.0	172.6
Gathering and other expense	15.5	—	15.5
General and administrative	221.7	—	221.7
Production and property taxes	130.8	—	130.8
Depreciation, depletion and amortization	857.1	—	857.1
Exploration expenses	0.3	—	0.3
Impairment	1,560.9	—	1,560.9
Total Operating Expenses	3,218.0	55.0	3,273.0
Net gain (loss) from asset sales, inclusive of restructuring costs	25.0	—	25.0
OPERATING INCOME (LOSS)	(1,260.4)	—	(1,260.4)
Realized and unrealized gains (losses) on derivative contracts (Note 7)	90.4	—	90.4
Interest and other income (expense)	(9.6)	—	(9.6)
Interest expense	(149.4)	—	(149.4)
INCOME (LOSS) BEFORE INCOME TAXES	(1,329.0)	—	(1,329.0)
Income tax (provision) benefit	317.4	—	317.4
NET INCOME (LOSS)	$ (1,011.6)	$ —	$ (1,011.6)
Earnings (loss) per common share			
Basic	$ (4.25)	$ —	$ (4.25)
Diluted	$ (4.25)	$ —	$ (4.25)
Weighted-average common shares outstanding			
Used in basic calculation	237.9	—	237.9
Used in diluted calculation	237.9	—	237.9

(1) This column excludes the impact of adopting ASC Topic 606 and is consistent with the presentation prior to January 1, 2018.

The following tables present our revenues that are disaggregated by revenue source and by geographic area. Transportation and processing costs in the following tables are not all of the transportation and processing costs that the Company incurs, only the expenses that are netted against revenues pursuant to ASC Topic 606.

	Oil and condensate sales	Gas sales	NGL sales	Transportation and processing costs included in revenue	Oil and condensate, gas and NGL sales, as reported
	(in millions)				
	Year Ended December 31, 2018				
Northern Region					
Williston Basin	$707.0	$45.3	$56.5	$ (43.1)	$ 765.7
Uinta Basin	25.3	25.0	4.8	—	55.1
Other Northern[1]	4.9	2.0	—	—	6.9
Southern Region					
Permian Basin	684.4	17.3	49.5	(11.9)	739.3
Haynesville/Cotton Valley	1.0	303.1	—	—	304.1
Other Southern	(0.2)	0.4	—	—	0.2
Total oil and condensate, gas and NGL sales	$1,422.4	$393.1	$110.8	$ (55.0)	$ 1,871.3
	Year Ended December 31, 2017[2]				
Northern Region					
Williston Basin	$586.5	$42.3	$51.5	$ —	$ 680.3
Pinedale	18.0	154.8	31.8	—	204.6
Uinta Basin	29.6	50.0	5.9	—	85.5
Other Northern	4.9	16.6	0.3	—	21.8
Southern Region					
Permian Basin	298.8	15.5	22.0	—	336.3
Haynesville/Cotton Valley	1.2	214.4	0.4	—	216.0
Other Southern	0.4	0.4	—	—	0.8
Total oil and condensate, gas and NGL sales	$939.4	$494.0	$111.9	$ —	$ 1,545.3
	Year Ended December 31, 2016[2]				
Northern Region					
Williston Basin	$541.6	$33.1	$22.7	$ —	$ 597.4
Pinedale	25.8	194.1	40.6	—	260.5
Uinta Basin	28.0	52.5	6.4	—	86.9
Other Northern	5.0	18.7	0.3	—	24.0
Southern Region					
Permian Basin	166.1	11.6	12.9	—	190.6
Haynesville/Cotton Valley	1.1	106.6	0.4	—	108.1
Other Southern	1.5	0.5	0.2	—	2.2
Total oil and condensate, gas and NGL sales	$769.1	$417.1	$83.5	$ —	$ 1,269.7

(1) For the year ended December 31, 2018, immaterial amounts of revenue associated with adjustments in Pinedale have been included in Other Northern.
(2) Prior period amounts have not been adjusted under the modified retrospective method.

Note 3 – Acquisitions and Divestitures

Acquisitions

2017 Permian Basin Acquisition

In the fourth quarter of 2017, QEP acquired additional oil and gas properties in the Permian Basin for an aggregate purchase price of $721.0 million (2017 Permian Basin Acquisition). The 2017 Permian Basin Acquisition consists of approximately 15,100 acres, mainly in Martin County, Texas, which are held by production from existing vertical wells. QEP structured the transaction as a like-kind exchange under Section 1031 of the Internal Revenue Service Code and funded the purchase price with the proceeds from the Pinedale Divestiture (defined below). The 2017 Permian Basin Acquisition meets the definition of an asset acquisition because substantially all of the total fair value acquired relates to undeveloped leaseholds which do not have outputs. During the year ended December 31, 2018, QEP closed $49.1 million of acquisitions from various entities that owned additional oil and gas interests in certain properties included in the 2017 Permian Basin Acquisition on substantially the same terms and conditions as the 2017 Permian Basin Acquisition.

2016 Permian Basin Acquisition

In October 2016, QEP acquired oil and gas properties in the Permian Basin for an aggregate purchase price of approximately $591.0 million (2016 Permian Basin Acquisition). The 2016 Permian Basin Acquisition consists of approximately 9,600 net acres in Martin County, Texas, which are primarily held by production from existing vertical wells. The 2016 Permian Basin Acquisition was funded with cash on hand, which included proceeds from an equity offering in June 2016.

The 2016 Permian Basin Acquisition meets the definition of a business combination under ASC 805, Business Combinations, as it included significant proved properties. QEP allocated the cost of the 2016 Permian Basin Acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Revenues of $498.4 million and $80.2 million and net income of $282.4 million and $221.4 million were generated from the acquired properties for the years ended December 31, 2018 and 2017. Revenues of $3.8 million and a net loss of $0.7 million were generated from the acquired properties from October 19, 2016 to December 31, 2016. The revenue and net income (loss) are included in QEP's Consolidated Statements of Operations. During the year ended December 31, 2016, QEP incurred acquisition-related costs of $2.3 million, which are included in "General and administrative" expense on the Consolidated Statements of Operations. In conjunction with the 2016 Permian Basin Acquisition, the Company recorded a $17.8 million bargain purchase gain. The acquisition resulted in a bargain purchase gain primarily as a result of an increase in future oil prices from the execution of the purchase and sale agreement to the closing date of the acquisition. The bargain purchase gain is reported on the Consolidated Statements of Operations within "Interest and other income (expense)".

The following table presents a summary of the Company's final purchase accounting entries (in millions):

Consideration:	
Total consideration	$591.0
Amounts recognized for fair value of assets acquired and liabilities assumed:	
Proved properties	$406.2
Unproved properties	214.2
Asset retirement obligations	(11.6)
Bargain purchase gain	(17.8)

Total fair value	$591.0

The following unaudited, pro forma results of operations are provided for the year ended December 31, 2016. Pro forma results are not provided for the years ended December 31, 2018 and 2017, because the 2016 Permian Basin Acquisition occurred during the fourth quarter of 2016; and therefore, the results are included in QEP's results of operations for the years ended December 31, 2018 and 2017. The supplemental pro forma results of operations are provided for illustrative purposes only and may not be indicative of the actual results that would have been achieved by the acquired properties for the periods presented, or that may be achieved by such properties in the future. Future results may vary significantly from the results reflected in this pro forma financial information because of future events and transactions, as well as other factors. The pro forma information is based on QEP's consolidated results of operations for the year ended December 31, 2016, the acquired properties' historical results of operations and estimates of the effect of the transaction on the combined results. The pro forma results of operations have been prepared by adjusting, and quantifying, the historical results of QEP to include the historical results of the acquired properties based on information provided by the seller and the impact of the purchase price allocation. The pro forma results of operations do not include any cost savings or other synergies that may result from the 2016 Permian Basin Acquisition or any estimated costs that have been or will be incurred by the Company to integrate the acquired properties.

	Year ended December 31, 2016	
	Actual	Pro forma
	(in millions, except per share amounts)	
Revenues	$1,377.1	$1,392.5
Net income (loss)	$(1,245.0)	$(1,246.8)
Earnings (loss) per common share		
Basic	$(5.62)	$(5.62)
Diluted	$(5.62)	$(5.62)

Other Acquisitions

In addition to the acquisitions related to the 2017 Permian Basin Acquisition, during the year ended December 31, 2018, QEP acquired various oil and gas properties, which primarily included proved and unproved leasehold acreage in the Permian Basin for an aggregate purchase price of $16.5 million, subject to post-closing purchase price adjustments.

In addition to the 2017 Permian Basin Acquisition, QEP acquired various oil and gas properties in 2017, which primarily included undeveloped leasehold acreage, producing wells and additional surface acreage in the Permian Basin, for an aggregate purchase price of $94.5 million, subject to post-closing purchase price adjustments. In conjunction with the acquisitions, the Company recorded $5.3 million of goodwill, which was subsequently impaired.

In addition to the 2016 Permian Basin Acquisition, QEP acquired various oil and gas properties in 2016, primarily in the Permian and Williston basins, for an aggregate purchase price of $54.6 million, which included acquisitions of additional interests in QEP operated wells and additional undeveloped leasehold acreage. In conjunction with the acquisitions, the Company recorded $3.7 million of goodwill, which was subsequently impaired, and a $4.4 million bargain purchase gain. The bargain purchase gain is reported on the Consolidated Statements of Operations within "Interest and other income (expense)".

Divestitures

In February 2018, QEP's Board of Directors unanimously approved certain strategic and financial initiatives (2018 Strategic Initiatives) including plans to market its assets in the Williston Basin, the Uinta Basin and Haynesville/Cotton Valley and focus its activities in the Permian Basin. As of December 31, 2018, the Company closed the sale of its Uinta Basin assets and entered into purchase and sale agreements for its Williston Basin and Haynesville/Cotton Valley assets. Assets are considered held for sale once it is deemed unlikely that there will be any significant changes to QEP's divestiture plan. Refer to Note 16 – Subsequent Events for more information.

Haynesville/Cotton Valley Divestiture

In November 2018, the Company's wholly owned subsidiaries, QEP Energy Company, QEP Marketing Company, and QEP Oil & Gas Company, entered into a definitive agreement to sell its assets in Haynesville/Cotton Valley for a purchase price of $735.0 million, subject to purchase price adjustments, including adjustments for certain title and environmental defects asserted prior to the closing (Haynesville Divestiture). In January 2019, QEP closed the Haynesville Divestiture for net cash proceeds of $605.1 million, subject to post-closing purchase price adjustments. In addition, $32.2 million was placed in escrow due to title defects asserted prior to closing, to be resolved pursuant to the purchase and sale agreement's title dispute resolution procedures. Since the transaction was substantially finalized as of December 31, 2018, the assets and liabilities associated with the Haynesville Divestiture have been classified as noncurrent assets and liabilities held for sale on the Consolidated Balance Sheets and the notes accompanying the Consolidated Financial Statements. In addition, QEP recorded $3.0 million of estimated restructuring costs related to this divestiture during the year ended December 31, 2018, included in "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations. Refer to Note 8 – Restructuring Costs for more information.

The following table presents the carrying amounts of the major classes of assets and liabilities classified as noncurrent assets and liabilities held for sale on the Consolidated Balance Sheets:

	December 31, 2018	December 31, 2017[(1)]
	(in millions)	
Assets		
Current assets, total	$1.2	$3.4
Property, Plant and Equipment	683.7	1,290.3
Other noncurrent assets	7.8	27.2
Noncurrent assets held for sale	$692.7	$1,320.9
Liabilities		
Current liabilities, total	$3.4	$4.5
Asset retirement obligations, current	0.7	4.7
Asset retirement obligations, long-term	56.9	102.5
Fair value of derivative contracts, long-term	—	(3.0)
Other long-term liabilities	0.3	0.5
Other long-term liabilities held for sale	$61.3	$109.2

(1) For the year ended December 31, 2017, the asset and liabilities held for sale also includes the Uinta Basin Divestiture.

Planned Williston Basin Divestiture

In November 2018, the Company's wholly owned subsidiary, QEP Energy Company, entered into a purchase and sale agreement for its assets in the Williston Basin for a purchase price of $1,725.0 million, subject to purchase price adjustments which may be material (Planned Williston Basin Divestiture). The purchase price is comprised of $1,650.0 million in cash and contractual rights to receive $75.0 million of the buyer's common stock if certain conditions are met. The transaction is subject to certain conditions, including, but not limited to, approval of buyer's shareholders and regulatory approvals. As of December 31, 2018, the Williston Basin assets were classified as held and used in the Company's Consolidated Financial Statements as the assets did not meet the held for sale criteria. As a part of the 2018 Strategic Initiatives, QEP has incurred or expects to incur costs associated with contractual termination benefits, including severance, accelerated vesting of share-based compensation and other expenses. Refer to Note 8 – Restructuring Costs and Note 16 – Subsequent Events for more information.

Uinta Basin Divestiture

In September 2018, QEP sold substantially all of its natural gas and oil producing properties, undeveloped acreage and related assets located in the Uinta Basin for net cash proceeds of $153.0 million, subject to post-closing purchase price adjustments (Uinta Basin Divestiture). During the year ended December 31, 2018, QEP recorded a pre-tax loss of $12.6 million related to the Uinta Basin Divestiture, which included $5.4 million related to estimated restructuring costs recorded on the Consolidated Statements of Operations within "Net gain (loss) from asset sales, inclusive of restructuring costs". In conjunction with the Uinta Basin Divestiture, QEP recorded $402.8 million of proved and unproved properties impairment during the year ended December 31, 2018. Refer to Note 1 – Summary of Significant Accounting Policies and Note 8 – Restructuring Costs for more information.

Pinedale Divestiture

In September 2017, QEP sold its Pinedale assets (Pinedale Divestiture), for net cash proceeds (after purchase price adjustments) of $718.2 million. During the year ended December 31, 2017 QEP recorded a pre-tax gain on sale of $180.4 million, which was recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations. For the year ended December 31, 2018, QEP recorded a pre-tax gain on sale of $1.2 million, due to additional post-closing purchase price adjustments.

QEP agreed to reimburse the buyer for certain deficiency charges it incurs related to gas processing and NGL transportation and fractionation contracts, if any, between the effective date of the sale and December 31, 2019, in an aggregate amount not to exceed $45.0 million. As of December 31, 2018, the liability associated with estimated future payments for this commitment was $9.3 million and is reported on the Consolidated Balance Sheets within "Accounts payable and accrued expenses".

For the year ended December 31, 2017, QEP recorded net income before income taxes related to Pinedale, prior to the divestiture of $251.0 million, which includes the pre-tax gain on sale of $180.4 million. For the year ended December 31, 2016, QEP recorded a net loss before income taxes of $1,152.7 million. The net loss before income taxes was primarily due to an impairment on proved properties of $1,164.0 million recognized in 2016 as a result of a decrease in expected future gas prices.

Other Divestitures

In addition to the Uinta Basin Divestiture, during the year ended December 31, 2018, QEP received net cash proceeds of $90.6 million and recorded a net pre-tax gain on sale of $38.5 million related to the divestiture of properties outside our main operating areas.

In addition to the Pinedale Divestiture, during the year ended December 31, 2017, QEP also sold its Central Basin Platform assets (Central Basin Platform Divestiture) and received net cash proceeds of $3.5 million. Refer to Note 4 – Capitalized Exploratory Well Costs for more information. In addition, QEP received net cash proceeds of $85.1 million and recorded a pre-tax gain on sale of $33.1 million, primarily related to the sale of properties in the Other Northern area.

During the year ended December 31, 2016, QEP sold its interest in certain non-core properties, primarily in the Other Southern area for aggregate proceeds of $29.0 million and recorded a pre-tax gain on sale of $8.6 million.

These gains and losses are reported on the Consolidated Statements of Operations within "Net gain (loss) from asset sales, inclusive of restructuring costs".

Note 4 – Capitalized Exploratory Well Costs

Net changes in capitalized exploratory well costs are presented in the table below.

	Capitalized Exploratory Well Costs		
	2018	2017	2016
	(in millions)		
Balance at January 1,	$—	$14.2	$2.6
Additions to capitalized exploratory well costs	—	10.7	11.7
Reclassifications to proved properties	—	(3.6)	—
Capitalized exploratory well costs charged to expense	—	(21.3)	(0.1)
Balance at December 31,	$—	$—	$14.2

The balance at December 31, 2016 represents the amount of capitalized exploratory well costs that were pending the determination of proved reserves.

During the years ended December 31, 2017 and 2016, QEP's exploratory well activity was related to the Central Basin Platform exploration project in the Permian Basin targeting the Woodford Formation. QEP completed a second exploratory well related to this project in the first half of 2017. During the year ended December 31, 2017, based on the performance of the two exploratory wells that were drilled and the analysis of the ultimate economic feasibility of this exploration project, QEP determined it would no longer pursue the development of the Central Basin Platform exploration project and would seek to monetize the assets. QEP charged $21.3 million of exploratory well costs to exploration expense. In conjunction with the expensing of the exploratory well costs, QEP charged $28.3 million of the associated unproved leasehold acreage in the Central Basin Platform to impairment expense during the year ended December 31, 2017. QEP wrote down the Central Basin Platform assets to their fair market value of $3.6 million and reclassified the assets to proved properties. During the fourth quarter of 2017, QEP closed the Central Basin Platform Divestiture for net cash proceeds of $3.5 million.

Note 5 – Asset Retirement Obligations

QEP records ARO associated with the retirement of tangible, long-lived assets. The Company's ARO liability applies primarily to abandonment costs associated with oil and gas wells and certain other properties. The fair values of such costs are estimated by Company personnel based on abandonment costs of similar assets and depreciated over the life of the related assets. Revisions to the ARO estimates result from changes in expected cash flows or material changes in estimated asset retirement costs. The ARO liability is adjusted to present value each period through an accretion calculation using a credit-adjusted risk-free interest rate.

The Consolidated Balance Sheet line items of QEP's ARO liability are presented in the table below:

	Asset Retirement Obligations	
	December 31,	
	2018	2017
Balance Sheet line item	(in millions)	
Current:		
Asset retirement obligations, current liability	$5.1	$2.8
Long-term:		
Asset retirement obligations	96.9	104.1

Other long-term liabilities held for sale	57.6	107.2
Total ARO Liability	$159.6	$214.1

The following is a reconciliation of the changes in the Company's ARO for the periods specified below:

	Asset Retirement Obligations	
	2018	2017
	(in millions)	
ARO liability at January 1,	$214.1	$231.6
Accretion	6.4	7.7
Additions[1]	4.1	23.5
Revisions	(4.9)	8.5
Liabilities related to assets sold[2]	(56.8)	(34.9)
Liabilities settled	(3.3)	(22.3)
ARO liability at December 31,	$159.6	$214.1

(1) Additions for the year ended December 31, 2017, include $14.2 million related to the 2017 Permian Basin Acquisition. Refer to Note 3 – Acquisitions and Divestitures for more information.

(2) Liabilities related to assets sold for the year ended December 31, 2018, includes $51.0 million related to the Uinta Basin Divestiture. Liabilities related to assets sold for the year ended December 31, 2017 includes $34.9 million related to the Pinedale Divestiture. Refer to Note 3 – Acquisitions and Divestitures for more information.

Note 6 – Fair Value Measurements

QEP measures and discloses fair values in accordance with the provisions of ASC 820, Fair Value Measurements and Disclosures. This guidance defines fair value in applying GAAP, establishes a framework for measuring fair value and expands disclosures about fair value measurements. ASC 820 also establishes a fair value hierarchy. Level 1 inputs are quoted prices (unadjusted) for identical assets or liabilities in active markets that the Company has the ability to access at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability.

QEP has determined that its commodity derivative instruments are Level 2. The Level 2 fair value of commodity derivative contracts (refer to Note 7 – Derivative Contracts for more information) is based on market prices posted on the respective commodity exchange on the last trading day of the reporting period and industry standard discounted cash flow models. QEP primarily applies the market approach for recurring fair value measurements and maximizes its use of observable inputs and minimizes its use of unobservable inputs. QEP considers bid and ask prices for valuing the majority of its assets and liabilities measured and reported at fair value. In addition to using market data, QEP makes assumptions in valuing its assets and liabilities, including assumptions about risk and the risks inherent in the inputs to the valuation technique. The Company's policy is to recognize significant transfers between levels at the end of the reporting period.

Certain of the Company's commodity derivative instruments are valued using industry standard models that consider various inputs, including quoted forward prices for commodities, time value, volatility, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable prices at which transactions are executed in the marketplace. The determination of fair value for derivative assets and liabilities also incorporates nonperformance risk for counterparties and for QEP. Derivative contract fair values are reported on a net basis to the extent a legal right of offset with the counterparty exists.

The fair value of financial assets and liabilities at December 31, 2018 and 2017, is shown in the table below:

	Fair Value Measurements				
	Gross Amounts of Assets and Liabilities			Netting Adjustments[1]	Net Amounts Presented on the Consolidated Balance Sheets
	Level 1	Level 2	Level 3		
	(in millions)				
	December 31, 2018				
Financial Assets					
Fair value of derivative contracts – short-term[2]	$ —	$ 88.2	$ —	$ (0.4)	$ 87.8
Fair value of derivative contracts – long-term	—	35.4	—	—	35.4
Total financial assets	$ —	$ 123.6	$ —	$ (0.4)	$ 123.2
Financial Liabilities					
Fair value of derivative contracts – short-term	$ —	$ 0.4	$ —	$ (0.4)	$ —
Fair value of derivative contracts – long-term	—	0.7	—	—	0.7
Total financial liabilities	$ —	$ 1.1	$ —	$ (0.4)	$ 0.7
	December 31, 2017				
Financial Assets					
Fair value of derivative contracts – short-term	$ —	$ 20.6	$ —	$ (17.2)	$ 3.4
Fair value of derivative contracts – long-term	—	2.3	—	(2.2)	0.1
Total financial assets	$ —	$ 22.9	$ —	$ (19.4)	$ 3.5
Financial Liabilities					
Fair value of derivative contracts – short-term	$ —	$ 120.8	$ —	$ (17.2)	$ 103.6
Fair value of derivative contracts – long-term[2]	—	34.0	—	(2.2)	31.8
Total financial liabilities	$ —	$ 154.8	$ —	$ (19.4)	$ 135.4

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(1) The Company nets its derivative contract assets and liabilities outstanding with the same counterparty on the Consolidated Balance Sheets for the contracts that contain netting provisions. Refer to Note 7 – Derivative Contracts for more information regarding the Company's derivative contracts.

(2) Includes fair value of derivative contracts classified as "Noncurrent assets held for sale" of $0.3 million as of December 31, 2018 and "Other long-term liabilities held for sale" of $3.0 million as of December 31, 2017 on the Consolidated Balance Sheets related to the Haynesville Divestiture.

The following table discloses the fair value and related carrying amount of certain financial instruments not disclosed in other Notes to the Consolidated Financial Statements in this Annual Report on Form 10-K:

	Carrying Amount	Level 1 Fair Value	Carrying Amount	Level 1 Fair Value
	December 31, 2018		December 31, 2017	
Financial Assets	(in millions)			
Cash and cash equivalents	$—	$—	$—	$—
Financial Liabilities				
Checks outstanding in excess of cash balances	$14.6	$14.6	$44.0	$44.0
Long-term debt	$2,507.1	$2,350.5	$2,160.8	$2,256.2

The carrying amounts of cash and cash equivalents and checks outstanding in excess of cash balances approximate fair value. The fair value of fixed-rate long-term debt is based on the trading levels and dollar prices for the Company's debt at the end of the year. The carrying amount of variable-rate long-term debt approximates fair value because the floating interest rate paid on such debt was set for periods of one month.

The fair value of the deficiency charge obligation associated with the Pinedale Divestiture was measured utilizing an internally developed cash flow model discounted at QEP's weighted average cost of debt. Given the unobservable nature of the inputs, the fair value calculation associated with the deficiency charges is considered Level 3 within the fair value hierarchy. Refer to Note 3 – Acquisitions and Divestitures for more information.

The initial measurement of ARO at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with property, plant and equipment. Significant Level 3 inputs used in the calculation of ARO include plugging costs and reserve lives. A reconciliation of the Company's ARO is presented in Note 5 – Asset Retirement Obligations.

Nonrecurring Fair Value Measurements

The provisions of the fair value measurement standard are also applied to the Company's nonrecurring measurements. The Company utilizes fair value on a periodic basis, at least annually, to review its proved oil and gas properties for potential impairment when events and changes in circumstances indicate that the carrying amount of such property may not be recoverable. The fair value of property is measured utilizing the income approach, and utilizing inputs that are primarily based upon internally developed cash flow models discounted at an appropriate weighted average cost of capital. In addition, the signing of a purchase and sale agreement could also trigger an impairment of proved properties. For assets subject to a purchase and sale agreement, the terms of the purchase and sale agreement are used as an indicator of fair value. If a range is estimated for the amount of possible future cash flows, the fair value of property is measured utilizing a probability-weighted approach whereas the likelihood of possible outcomes is taken into consideration. Specific to the Planned Williston Basin Divestiture, the Company obtained a Black-Scholes-Merton estimate of the value of the contractual rights to receive up to 5.8 million shares of the buyer's common stock at December 31, 2018. The estimated fair value of these contractual rights at December 31, 2018 was determined using a five-year contractual period, a 5% risk-free interest rate and a 49.3% weighted-average expected price volatility. Given the unobservable nature of the inputs, fair value calculations associated with proved oil and gas property impairments are considered Level 3 within the fair value hierarchy. During the years ended December 31, 2018, 2017 and 2016, the Company recorded impairments on certain proved oil and gas properties of $1,524.6 million, $38.1 million and $1,172.7 million, respectively, resulting in a reduction of the associated carrying value to fair value. Refer to Note 1 – Summary of Significant Accounting Policies for more information on impairment of oil and gas properties.

Acquisitions of proved and unproved properties are also measured at fair value on a nonrecurring basis. The Company utilizes a discounted cash flow model to estimate the fair value of acquired property as of the acquisition date which utilizes the following inputs to estimate future net cash flows: (i) estimated quantities of oil and condensate, gas and NGL reserves; (ii) estimates of future commodity prices; and (iii) estimated production rates, future operating and development costs, which are based on the Company's historic experience with similar properties. In some instances, market comparable information of recent transactions is used to estimate fair value of unproved acreage. Due to the unobservable characteristics of the inputs, the fair value of the acquired properties is considered Level 3 within the fair value hierarchy. Refer to Note 3 – Acquisitions and Divestitures for more information on the fair value of acquired properties.

Note 7 – Derivative Contracts

QEP has established policies and procedures for managing commodity price volatility through the use of derivative instruments. In the normal course of business, QEP uses commodity price derivative instruments to reduce the impact of potential downward movements in commodity prices on cash flow, returns on capital investment, and other financial results. However, these instruments typically limit gains from favorable price movements. The volume of production subject to commodity derivative instruments and the mix of the instruments are frequently evaluated and adjusted by management in response to changing market conditions. QEP may enter into commodity derivative contracts for up to 100% of forecasted production, but generally, QEP enters into commodity derivative contracts for approximately 50% to 75% of its forecasted annual production by the end of the first quarter of each fiscal year. In addition, QEP has historically entered into commodity derivative contracts on a portion of its storage transactions. QEP does not enter into commodity derivative contracts for speculative purposes.

QEP uses commodity derivative instruments known as fixed-price swaps or costless collars to realize a known price or price range for a specific volume of production delivered into a regional sales point. QEP's commodity derivative instruments do not require the physical delivery of oil or gas between the parties at settlement. All transactions are settled in cash with one party paying the other for the net difference in prices, multiplied by the contract volume, for the settlement period. Oil price derivative instruments are typically structured as NYMEX fixed-price swaps based at Cushing, Oklahoma. Gas price derivative instruments are typically structured as fixed-price swaps or costless collars at NYMEX Henry Hub or regional price indices. QEP also enters into oil and gas basis swaps to achieve a fixed-price swap for a portion of its oil and gas sales at prices that reference specific regional index prices.

QEP does not currently have any commodity derivative transactions that have margin requirements or collateral provisions that would require payments prior to the scheduled settlement dates. QEP's commodity derivative contract counterparties are typically financial institutions and energy trading firms with investment-grade credit ratings. QEP routinely monitors and manages its exposure to counterparty risk by requiring specific minimum credit standards for all counterparties, actively monitoring counterparties' public credit ratings and avoiding the concentration of credit exposure by transacting with multiple counterparties. The Company has master-netting agreements with some counterparties that allow the offsetting of receivables and payables in a default situation.

Derivative Contracts – Production

The following table presents QEP's volumes and average prices for its commodity derivative swap contracts as of December 31, 2018:

Year	Index	Total Volumes	Average Swap Price per Unit
		(in millions)	
Oil sales		(bbls)	($/bbl)
2019	NYMEX WTI	11.0	$ 54.49
2020	NYMEX WTI	2.9	$ 62.37
Gas sales		(MMBtu)	($/MMBtu)
2019	NYMEX HH	43.8	$ 2.86

QEP uses oil basis swaps, combined with NYMEX WTI fixed price swaps, to achieve fixed price swaps for the location at which it sells its physical production. The following table presents details of QEP's oil basis swaps as of December 31, 2018:

Year	Index	Basis

Oil sales			Total Volumes (in millions) (bbls)	Weighted-Average Differential ($/bbl)
2019	NYMEX WTI	Argus WTI Midland	6.6	$ (2.22)
2019	NYMEX WTI	Argus WTI Houston	0.4	$ 4.35
2020	NYMEX WTI	Argus WTI Midland	1.5	$ (1.01)

QEP Derivative Financial Statement Presentation

The following table identifies the Consolidated Balance Sheet location of QEP's outstanding derivative contracts on a gross contract basis as opposed to the net contract basis presentation on the Consolidated Balance Sheets and the related fair values at the balance sheet dates:

		Gross asset derivative instruments fair value		Gross liability derivative instruments fair value	
		December 31,			
	Balance Sheet line item	2018	2017	2018	2017
Current:		(in millions)			
Commodity	Fair value of derivative contracts	$88.2	$20.6	$0.4	$120.8
Long-term:					
Commodity	Fair value of derivative contracts	35.4	2.3	0.7	34.0
Total derivative instruments[(1)]		$123.6	$22.9	$1.1	$154.8

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(1) Includes fair value of derivative contracts classified as "Noncurrent assets held for sale" of $0.3 million as of December 31, 2018 and "Other long-term liabilities held for sale" of $3.0 million as of December 31, 2017 on the Consolidated Balance Sheets related to the Haynesville Divestiture.

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Derivative contracts	Year Ended December 31,		
	2018	2017	2016
Realized gains (losses) on commodity derivative contracts	(in millions)		
Production			
Oil derivative contracts	$(153.4)	$6.8	$86.3
Gas derivative contracts	(5.0)	(22.3)	44.8
Gas Storage			
Gas derivative contracts	0.3	—	2.9
Realized gains (losses) on commodity derivative contracts	(158.1)	(15.5)	134.0
Unrealized gains (losses) on commodity derivative contracts			
Production			
Oil derivative contracts	277.0	(66.2)	(217.2)
Gas derivative contracts	(22.3)	133.6	(145.4)
Gas Storage			
Gas derivative contracts	(0.3)	2.5	(4.4)
Unrealized gains (losses) on commodity derivative contracts	254.4	69.9	(367.0)
Total realized and unrealized gains (losses) on commodity derivative contracts related to production and storage contracts	$96.3	$54.4	$(233.0)
Derivatives associated with Uinta and Pinedale divestitures			
Unrealized gains (losses) on commodity derivative contracts			
Production			
Oil derivative contracts	$(2.7)	$(1.3)	$—
Gas derivative contracts	—	(23.5)	—
NGL derivative contracts	(3.2)	(5.1)	—
Unrealized gains (losses) on commodity derivative contracts related to divestitures[(1)(2)]	$(5.9)	$(29.9)	$—
Total realized and unrealized gains (losses) on commodity derivative contracts	$90.4	$24.5	$(233.0)

(1) During the year ended December 31, 2018, the unrealized gains (losses) on commodity derivative contracts related to the Uinta Basin Divestiture are comprised of derivatives entered into in conjunction with the execution of the Uinta Basin purchase and sale agreement, which were subsequently novated to the buyer upon the closing of the sale in September 2018. Refer to Note 3 – Acquisitions and Divestitures for more information. The unrealized gains (losses) on commodity derivatives associated with the Uinta Basin Divestiture are offset by an equal amount recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations.

(2) During the year ended December 31, 2017, the unrealized gains (losses) on commodity derivative contracts related to the Pinedale Divestiture are comprised of derivatives entered into in conjunction with the execution of the Pinedale purchase and sale agreement, which were subsequently novated to the buyer upon the closing of the sale in September 2017. Refer to Note 3 – Acquisitions and Divestitures for more information. The unrealized gains (losses) on commodity derivatives associated with the Pinedale Divestiture are offset by an equal amount recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations.

Note 8 – Restructuring Costs

In connection with our 2018 Strategic Initiatives, QEP has incurred or expects to incur restructuring costs associated with contractual termination benefits including severance, accelerated vesting of share-based compensation and other expenses. The termination benefits will be accounted for under ASC 712, Compensation – Nonretirement Postemployment Benefits and ASC 718, Compensation – Stock Compensation.

Restructuring costs recognized associated with the 2018 restructuring (2018 Restructuring) are summarized below:

	Year Ended December 31, 2018			
	Total recognized	Recognized in "General and administrative"	Recognized in "Net gain (loss) from asset sales, inclusive of restructuring costs"	Recognized in "Interest and other income (expense)"
	(in millions)			
Termination benefits	$32.3	$ 25.7	$ 6.6	—
Office lease termination costs	1.0	1.0	—	—
Accelerated share-based compensation[1]	11.0	8.8	2.2	—
Retention expense (including share-based compensation)	18.8	18.8	—	—
Pension and Medical Plan curtailment	0.1	—	(0.2)	0.3
Total restructuring costs	$63.2	$ 54.3	$ 8.6	$ 0.3

(1) Accelerated share based compensation represents the additional expense or loss recognized in the Consolidated Statement of Operations for the year ended December 31, 2018. Total accelerated share based compensation was $11.2 million and was determined based on the contractual vesting date, with $11.0 million recognized in 2018 as shown above, and the remaining amount recognized in prior periods.

	Costs recognized period from inception to December 31, 2018	Total remaining costs expected to be incurred[4]	
	(in millions)		
Termination benefits	$32.3	$ —	[1]
Office lease termination costs	1.0	—	[1]
Accelerated share-based compensation	11.2	15.5	[1][2]
Retention expense (including share-based compensation)	18.8	21.4	[3]
Pension and Medical Plan curtailment	0.1	—	[1]
Total restructuring costs	$63.4	$ 36.9	

(1) Due to the nature of the strategic initiatives and uncertain factors such as the timing and terms of the potential divestitures, the Company is not able to reasonably estimate the total cost to be incurred as a part of these restructurings.

(2) In January 2019, QEP had $15.5 million of accelerated share-based compensation due to the departure of two officers. The accelerated share-based compensation of $15.5 million was determined based on the contractual vesting date with $6.0 million expected to be recognized in the first quarter of 2019 and the remaining amount previously recognized in 2018 and prior periods.

(3) QEP expects to incur an additional $3.9 million in 2019 related to the 2018 retention program and $17.5 million related to the 2019 retention program, which includes $16.0 million of cash and $1.5 million of share-based

compensation.

(4) Refer to the Note 16 – Subsequent Events for more information regarding expected restructuring costs.

The following table is a reconciliation of QEP's restructuring liability, which is included within "Accounts payable and accrued expenses" on the Consolidated Balance Sheets.

	Restructuring liability					
	Termination benefits	Office lease termination costs	Accelerated share-based compensation	Retention expense	Pension curtailment	Total
	(in millions)					
Balance at December 31, 2017	$—	$ —	$ 0.2	$ —	$ —	$0.2
Costs incurred and charged to expense	32.3	1.0	11.0	18.8	0.1	63.2
Costs paid or otherwise settled	(12.8)	(1.0)	(11.2)	(8.0)	(0.1)	(33.1)
Balance at December 31, 2018	$19.5	$ —	$ —	$ 10.8	$ —	$30.3

Note 9 – Debt

As of the indicated dates, the principal amount of QEP's debt consisted of the following:

	December 31,	
	2018	2017
	(in millions)	
Revolving Credit Facility due 2022	$430.0	$89.0
6.80% Senior Notes due 2020	51.7	51.7
6.875% Senior Notes due 2021	397.6	397.6
5.375% Senior Notes due 2022	500.0	500.0
5.25% Senior Notes due 2023	650.0	650.0
5.625% Senior Notes due 2026	500.0	500.0
Less: unamortized discount and unamortized debt issuance costs	(22.2)	(27.5)
Total long-term debt outstanding	$2,507.1	$2,160.8

Of the total debt outstanding on December 31, 2018, the 6.80% Senior Notes due March 1, 2020, the 6.875% Senior Notes due March 1, 2021, the 5.375% Senior Notes due October 1, 2022 and the 5.25% Senior Notes due May 1, 2023, will mature within the next five years. In addition, the revolving credit facility matures on September 1, 2022.

Credit Facility

QEP's revolving credit facility, which matures, subject to satisfaction of certain conditions, in September 2022, provides for loan commitments of $1.25 billion. The credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions. The credit agreement contains financial covenants (that are defined in the credit agreement) that limit the amount of debt the Company can incur and may limit the amount available to be drawn under the credit facility including: (i) a net funded debt to capitalization ratio that may not exceed 60%, (ii) a leverage ratio under which net funded debt may not exceed 4.00 times consolidated EBITDA (as defined in the credit agreement), through the fiscal quarter ending December 31, 2018, and 3.75 times thereafter, and (iii) during a ratings trigger period (as defined), a present value coverage ratio under which the present value of the Company's proved reserves must exceed net funded debt by 1.40 times commencing on January 1, 2019 through December 31, 2019, and must exceed net funded debt by 1.50 times at any time on or after January 1, 2020. As of December 31, 2018, the Company is not subject to the present value coverage ratio. As of December 31, 2018 and 2017, QEP was in compliance with the covenants under the credit agreement.

During the years ended December 31, 2018 and 2017, QEP's weighted-average interest rates on borrowings from its credit facility were 4.43% and 3.52%, respectively. As of December 31, 2018, QEP had $430.0 million of borrowings outstanding and $0.3 million in letters of credit outstanding under the credit facility. As of December 31, 2017, QEP had $89.0 million of borrowings outstanding and $1.0 million in letters of credit outstanding under the credit facility.

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Senior Notes
At December 31, 2018, the Company had $2,099.3 million principal amount of senior notes outstanding with maturities ranging from March 2020 to March 2026 and coupons ranging from 5.25% to 6.875%. The senior notes pay interest semi-annually, are unsecured senior obligations and rank equally with all of our other existing and future unsecured and senior obligations. QEP may redeem some or all of its senior notes at any time before their maturity at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. The indentures governing QEP's senior notes contain customary events of default and covenants that may limit QEP's ability to, among other things, place liens on its property or assets.

Note 10 – Commitments and Contingencies

The Company is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business. In each reporting period, the Company assesses these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in its Consolidated Financial Statements. In accordance with ASC 450, Contingencies, an accrual is recorded for a material loss contingency when its occurrence is probable and damages are reasonably estimable based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes.

Legal proceedings are inherently unpredictable and unfavorable resolutions can occur. Assessing contingencies is highly subjective and requires judgment about uncertain future events. When evaluating contingencies related to legal proceedings, the Company may be unable to estimate losses due to a number of factors, including potential defenses, the procedural status of the matter in question, the presence of complex legal and/or factual issues, the ongoing discovery and/or development of information important to the matter.

Landowner Litigation – In October, 2017, the owners of certain surface and mineral interests in Martin and Andrews County, Texas, filed suit against QEP, alleging QEP improperly used the surface of the properties and failed to correctly pay royalties, and seeking money damages and a declaratory judgment that portions of the oil and gas leases covering the properties are no longer in effect.

Mandan, Hidatsa and Arikara Nation ("MHA Nation") Title Dispute – In June 2018, the MHA Nation notified QEP of its position that QEP has no valid lease covering certain minerals underlying the Missouri and Little Missouri Riverbeds on the Fort Berthold Reservation in North Dakota. The MHA Nation also passed a resolution purporting to rescind those portions of QEP's IMDA lease covering the disputed minerals underlying the Missouri River.

The Company is unable to make an estimate of the range of reasonably possible loss related to its contingencies.

Commitments

QEP has contracted for gathering, processing and firm transportation services with various third parties. Market conditions, drilling activity and competition may prevent full utilization of the contractual capacity. In addition, QEP has contracts with third parties who provide drilling services. Annual payments and the corresponding years for gathering, processing, transportation, drilling and fractionation contracts are as follows:

Year	Amount (in millions)
2019	$ 72.2
2020	$ 55.4
2021	$ 31.3

2022	$ 27.1
2023	$ 15.3
After 2023	$ 66.0

QEP rents office space, compressors, generators and equipment throughout its scope of operations from third-party lessors. Expense from operating leases amounted to $30.3 million, $24.9 million, and $21.7 million during the years ended December 31, 2018, 2017 and 2016, respectively. Minimum future payments under the terms of long-term operating leases are as follows:

Year	Amount (in millions)
2019	$ 17.4
2020	$ 13.8
2021	$ 9.1
2022	$ 7.4
2023	$ 4.5
After 2023	$ —

Note 11 – Share-Based Compensation

In 2018, QEP's Board of Directors and QEP's shareholders approved the QEP Resources, Inc. 2018 Long-Term Incentive Plan (LTIP), which replaces the 2010 Long-Term Stock Incentive Plan (LTSIP) and provides for the issuance of up to 10.0 million shares such that the Board of Directors may grant long-term incentive compensation. QEP issues stock options, restricted share awards and restricted share units under its LTSIP or LTIP and awards performance share units under its CIP to certain officers, employees, and non-employee directors. Grants issued prior to May 15, 2018 are under the LTSIP and the grants issued on or after May 15, 2018 are under the LTIP. QEP recognizes the expense over the vesting periods for the stock options, restricted share awards, restricted share units and performance share units. There were 10.1 million shares available for future grants under the LTIP at December 31, 2018.

Share-based compensation expense is recognized within "General and administrative" expense on the Consolidated Statements of Operations and is summarized in the table below. During the year ended December 31, 2018, the Company recorded an additional $11.0 million of share-based compensation expense related to the acceleration of vesting that occurred as part of the restructuring program, of which $2.2 million for the year ended December 31, 2018 was recorded in "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations and the remaining $8.8 million is included in share-based compensation expense below (refer to Note 8 – Restructuring Costs for more information):

	Year Ended December 31,		
	2018	2017	2016
	(in millions)		
Stock options	$1.2	$2.3	$2.3
Restricted share awards	27.5	24.6	23.7
Performance share units	8.1	(4.5)	9.4
Restricted share units	0.1	—	0.2
Total share-based compensation expense	$36.9	$22.4	$35.6

Stock Options

QEP uses the Black-Scholes-Merton mathematical model to estimate the fair value of stock option awards at the date of grant. Fair value calculations rely upon subjective assumptions used in the mathematical model and may not be representative of future results. The Black-Scholes-Merton model is intended for calculating the value of options not traded on an exchange. The Company utilizes the "simplified" method to estimate the expected term of the stock options granted as there is limited historical exercise data available in estimating the expected term of the stock options. QEP uses a historical volatility method to estimate the fair value of stock options awards and the risk-free interest rate is based on the yield on U.S. Treasury strips with maturities similar to those of the expected term of the stock options. The stock options typically vest in equal installments over a three-year period from the grant date and are exercisable immediately upon vesting through the seventh anniversary of the grant date. To fulfill options exercised, QEP either reissues treasury stock or issues new shares. The Company recognizes forfeitures of stock options as they occur. In 2018, QEP did not issue stock options.

The calculated fair value of options granted and major assumptions used in the model at the date of grant are listed below:

	Stock Option Assumptions Year Ended December 31,	
	2017	2016
Weighted-average grant date fair value of awards granted during the period	$6.44	$3.77
Risk-free interest rate range	1.66% - 1.81%	0.99% - 1.15%
Weighted-average risk-free interest rate	1.8 %	1.2 %
Expected price volatility range	43.82% - 46.70%	43.42% - 43.66%
Weighted-average expected price volatility	43.9 %	43.4 %
Expected dividend yield	— %	— %
Expected term in years at the date of grant	4.5	4.5

Stock option transactions under the terms of the LTSIP are summarized below:

	Options Outstanding	Weighted-Average Exercise Price (per share)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in millions)
Outstanding at December 31, 2017	2,354,277	$ 23.62		
Exercised	(23,337)	10.12		
Cancelled	(232,007)	37.16		
Outstanding at December 31, 2018	2,098,933	$ 22.27	2.87	$ —
Options Exercisable at December 31, 2018	1,732,827	$ 23.90	2.46	$ —
Unvested Options at December 31, 2018	366,106	$ 14.57	4.81	$ —

The total intrinsic value (the difference between the market price at the exercise date and the exercise price) of stock options exercised was $0.1 million during the year ended December 31, 2018. During the years ended December 31, 2017 and 2016, there were no exercises of stock options. There was no income tax impact for the years ended December 31, 2018 and 2017. The Company realized an income tax benefit of $0.2 million for the year ended December 31, 2016. As of December 31, 2018, $0.4 million of unrecognized compensation cost related to stock options granted under the LTSIP is expected to be recognized over a weighted-average period of 1.19 years. The weighted-average vesting period may be reduced due to accelerated vesting under the restructuring program. Refer to Note 8 – Restructuring Costs for more information.

Restricted Share Awards

Restricted share award grants typically vest in equal installments over a three-year period from the grant date. The grant date fair value is determined based on the closing bid price of the Company's common stock on the grant date. The Company recognizes restricted share forfeitures as they occur. The total fair value of restricted share awards that vested during the years ended December 31, 2018, 2017 and 2016, was $21.5 million, $18.4 million and $24.3

million, respectively. There was no income tax impact for the years ended December 31, 2018 and 2017. The weighted-average grant date fair value of restricted share awards granted was $9.56 per share, $13.90 per share and $10.50 per share for the years ended December 31, 2018, 2017 and 2016, respectively. As of December 31, 2018, $15.2 million of unrecognized compensation cost related to restricted share awards granted under the LTSIP is expected to be recognized over a weighted-average vesting period of 1.98 years. The weighted-average vesting period may be reduced due to accelerated vesting of awards under the restructuring program. Refer to Note 8 – Restructuring Costs for more information.

Transactions involving restricted share awards under the terms of the LTSIP and LTIP are summarized below:

	Restricted Share Awards Outstanding	Weighted-Average Grant Date Fair Value
		(per share)
Unvested balance at December 31, 2017	3,721,334	$ 13.23
Granted	2,997,743	9.56
Vested	(2,630,959)	12.87
Forfeited	(265,985)	10.96
Unvested balance at December 31, 2018	3,822,133	$ 10.76

Performance Share Units

The payouts for performance share units are dependent upon the Company's total shareholder return compared to a group of its peers over a three-year period. The awards are denominated in share units and have historically been paid in cash. Beginning with awards granted in 2015, the Company has the option to settle earned awards in cash or shares of common stock under the Company's LTIP; however, as of December 31, 2018, the Company expects to settle all awards in cash under the CIP. These awards are classified as liabilities and are included within "Other long-term liabilities" on the Consolidated Balance Sheets. As these awards are dependent upon the Company's total shareholder return and stock price, they are measured at fair value at the end of each reporting period. The Company paid $2.8 million, $5.3 million and $2.8 million for vested performance share units during the years ended December 31, 2018, 2017 and 2016, respectively. The weighted-average grant date fair value of the performance share units granted during the years ended December 31, 2018, 2017 and 2016, was $9.55, $16.90, and $10.16 per share, respectively. As of December 31, 2018, $7.3 million of unrecognized compensation cost, which represents the unvested portion of the fair market value of performance shares granted, is expected to be recognized over a weighted-average vesting period of 1.84 years. The weighted-average vesting period may be reduced due to accelerated vesting under the restructuring program. Refer to Note 8 – Restructuring Costs for more information.

Transactions involving performance share units under the terms of the CIP are summarized below:

	Performance Share Units Outstanding	Weighted-Average Grant Date Fair Value
		(per share)
Unvested balance at December 31, 2017	1,199,336	$ 14.59
Granted	724,095	9.55
Vested	(364,119)	17.26
Unvested balance at December 31, 2018	1,559,312	$ 11.47

Restricted Share Units

Employees may elect to defer their grants of restricted share awards and these deferred awards are designated as restricted share units. Restricted share units vest over a three-year period and are deferred into the Company's nonqualified, unfunded deferred compensation plan at the time of vesting. These awards are ultimately paid in cash. They are classified as liabilities in "Other long-term liabilities" on the Consolidated Balance Sheets and are measured at fair value at the end of each reporting period. The weighted-average grant date fair value of the restricted share units was $9.55, $16.98 and $10.12 per share for the years ended December 31, 2018, 2017 and 2016, respectively. As of December 31, 2018, $0.1 million of unrecognized compensation cost, which represents the unvested portion of the fair market value of restricted share units granted, is expected to be recognized over a weighted-average vesting period of 0.88 years. The weighted-average vesting period may be reduced due to accelerated vesting of awards under the restructuring program. Refer to Note 8 – Restructuring Costs for more information.

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Transactions involving restricted share units under the terms of the LTSIP are summarized below:

	Restricted Share Units Outstanding	Weighted-Average Grant Date Fair Value (per share)
Unvested balance at December 31, 2017	21,946	$ 13.22
Granted	31,835	9.55
Vested	(11,106)	13.27
Unvested balance at December 31, 2018	42,675	$ 10.47

Note 12 – Employee Benefits

Pension and Other Postretirement Benefits

The Company provides pension and other postretirement benefits to certain employees through three benefit plans: the QEP Resources, Inc. Retirement Plan (Pension Plan), the Supplemental Executive Retirement Plan (SERP), and a postretirement medical plan (Medical Plan).

The Pension Plan is a closed, qualified, defined-benefit pension plan that is funded and provides pension benefits to certain QEP employees, which, as of December 31, 2018, covers 20 active and suspended participants, or 4%, of QEP's active employees, and 194 participants that are retired or were terminated and vested. Pension Plan benefits are based on the employee's age at retirement, years of service as of the earlier of the participant's termination of employment or December 31, 2015, and highest earnings in a consecutive 72 semi-monthly pay period during the 10 years preceding termination of employment or, if earlier, December 31, 2015. During the year ended December 31, 2018, the Company made contributions of $5.0 million to the Pension Plan and expects to contribute approximately $5.0 million to the Pension Plan in 2019. Contributions to the Pension Plan increase plan assets.

The SERP is a nonqualified retirement plan that is unfunded and provides pension benefits to certain QEP employees. SERP benefits are based on the employee's age at retirement, years of service and highest earnings in a consecutive 72 semi-monthly pay period during the 10 years preceding the participant's termination of employment. During the year ended December 31, 2018, the Company made contributions of $0.7 million to its SERP and expects to contribute approximately $0.5 million in 2019. Contributions to the SERP are used to fund current benefit payments. The SERP was amended and restated in June 2015 and is closed to new participants effective January 1, 2016.

During the year ended December 31, 2017, the Company recognized a $0.7 million loss on curtailment related to the SERP in connection with the Pinedale Divestiture, which was recorded on the Consolidated Statements of Operations within "Net gain (loss) from asset sales, inclusive of restructuring costs".

The Medical Plan is a self-insured plan. It is unfunded and provides other postretirement benefits including certain health care and life insurance benefits for certain retired QEP employees. The Medical Plan was originally provided only to employees hired by Questar Corporation before January 1, 1997. Of the 20 active, pension eligible employees, 12 are also eligible for the Medical Plan when they retire. As of December 31, 2018, 35 retirees are enrolled in the Medical Plan. The Company has capped its exposure to increasing medical costs by paying a fixed dollar monthly contribution toward these retiree benefits. The Company's contribution is prorated based on an employee's years of service at retirement; only those employees with 25 or more years of service receive the maximum company contribution. During the year ended December 31, 2018, the Company made contributions of $0.4 million and expects to contribute approximately $0.2 million of benefits in 2019. At December 31, 2018 and 2017, QEP's accumulated benefit obligation exceeded the fair value of its qualified retirement plan assets.

In February 2017, the Company changed the eligibility requirements for active employees eligible for the Medical Plan, as well as retirees currently enrolled. Effective July 1, 2017, the Company no longer offers the Medical Plan to a retiree and spouse that are both Medicare eligible. In addition, the Company no longer offers life insurance to individuals retiring on or after July 1, 2017.

The Company's execution of its strategic initiatives may trigger curtailments related to the Pension Plan, SERP and/or Medical Plan at the closing of the various transactions. Refer to Note 8 – Restructuring Costs for more information. The Company recognized a $0.3 million curtailment loss related to the Pension Plan as part of the Uinta Basin Divestiture, which is included in "Interest and other income (expense)" on the Consolidated Statements of Operations. The Company recognized a $0.2 million curtailment gain related to the Medical Plan as part of the continued divestiture activity included in "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations.

In accordance with the early adoption of ASU No. 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the presentation of net periodic pension cost and net periodic postretirement benefit cost, the Company recast years ended December 31, 2017 and 2016 by recognizing service costs related to SERP and Medical Plan benefits within "General and administrative" expense on the Consolidated Statements of Operations. All other expenses related to the Pension Plan, SERP and Medical Plan are recognized within "Interest and other income (expense)" on the Consolidated Statements of Operations.

The accumulated benefit obligation for all defined-benefit pension plans was $121.6 million and $128.7 million at December 31, 2018 and 2017, respectively.

The following table sets forth changes in the benefit obligations and fair value of plan assets for the Company's Pension Plan, SERP and Medical Plan for the years ended December 31, 2018 and 2017, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2018 and 2017:

	Pension Plan and SERP benefits		Medical Plan benefits	
	2018	2017	2018	2017
Change in benefit obligation	(in millions)			
Benefit obligation at January 1,	$130.0	$129.2	$2.9	$5.4
Service cost	0.8	0.8	—	—
Interest cost	4.6	4.7	0.1	0.1
Curtailments	0.1	(0.3)	—	—
Benefit payments	(5.8)	(6.9)	(0.4)	(0.1)
Plan amendments	—	—	—	(2.4)
Actuarial loss (gain)	(7.6)	2.5	(0.1)	(0.1)
Benefit obligation at December 31,	$122.1	$130.0	$2.5	$2.9
Change in plan assets				
Fair value of plan assets at January 1,	$100.5	$86.1	$—	$—
Actual return on plan assets	(7.1)	15.3	—	—
Company contributions to the plan	5.7	6.0	0.4	0.1
Benefit payments	(5.8)	(6.9)	(0.4)	(0.1)
Fair value of plan assets at December 31,	93.3	100.5	—	—
Underfunded status (current and long-term)	$(28.8)	$(29.5)	$(2.5)	$(2.9)
Amounts recognized in balance sheets				
Accounts payable and accrued expenses	$(1.1)	$(1.5)	$(0.2)	$(0.2)
Other long-term liabilities	(27.7)	(27.9)	(2.3)	(2.6)
Total amount recognized in balance sheet	$(28.8)	$(29.4)	$(2.5)	$(2.8)
Amounts recognized in AOCI				
Net actuarial loss (gain)	$19.4	$15.0	$(0.5)	$(0.5)
Prior service cost	0.4	1.2	(0.8)	(1.2)
Total amount recognized in AOCI	$19.8	$16.2	$(1.3)	$(1.7)

The following table sets forth the Company's Pension Plan, SERP and Medical Plan cost and amounts recognized in other comprehensive income (before tax) for the respective years ended December 31:

	Pension Plan and SERP benefits			Medical Plan benefits		
	2018	2017	2016	2018	2017	2016
Components of net periodic benefit cost	(in millions)					
Service cost	$0.8	$0.8	$1.2	$—	$—	$—
Interest cost	4.6	4.7	5.2	0.1	0.1	0.2
Expected return on plan assets	(5.8)	(5.4)	(5.6)	—	—	—
Curtailment loss	0.3	0.7	—	(0.2)	—	—
Settlements	—	0.2	—	—	—	—
Amortization of prior service costs	0.8	1.0	1.1	(0.3)	(0.3)	0.2
Amortization of actuarial loss	0.8	0.5	0.8	—	(0.1)	—
Periodic expense	$1.5	$2.5	$2.7	$(0.4)	$(0.3)	$0.4
Components recognized in accumulated other comprehensive income						
Current period prior service cost	$—	$(0.7)	$—	$0.2	$(2.5)	$—
Current period actuarial (gain) loss	5.6	(7.5)	8.5	(0.1)	(0.1)	0.4
Amortization of prior service cost	(0.8)	(1.0)	(1.1)	0.3	0.3	(0.2)
Amortization of actuarial gain (loss)	(0.8)	(0.5)	(0.8)	—	0.1	—
Loss on curtailment in current period	(0.1)	(0.3)	—	—	—	—
Settlements	—	(0.2)	—	—	—	—
Total amount recognized in accumulated other comprehensive income	$3.9	$(10.2)	$6.6	$0.4	$(2.2)	$0.2

The Company recognizes service costs related to SERP and Medical Plan benefits on the Consolidated Statements of Operations within "General and administrative" expense. All other expenses related to the Pension Plan, SERP and Medical Plan are recognized on the Consolidated Statements of Operations within "Interest and other income (expense)".

The estimated portion of net actuarial loss and net prior service cost for the Pension Plan and SERP that will be amortized from AOCI into net periodic benefit cost in 2019 is $1.8 million, which represents amortization of prior service cost recognized and actuarial losses. The estimated portion of net actuarial loss and net prior service cost for the Medical Plan that will be amortized from AOCI into net periodic benefit cost in 2019 is $0.3 million, which represents amortization of prior service cost recognized and actuarial gains. Amortization of prior service costs and actuarial gains or losses out of AOCI are recognized in the Consolidated Statements of Operations in "Interest and other income (expense)".

Following are the weighted-average assumptions (weighted by the plan level benefit obligation for pension benefits) used by the Company to calculate the Pension Plan, SERP and Medical Plan obligations at December 31, 2018 and 2017:

	Pension Plan and SERP benefits		Medical Plan benefits	
	2018	2017	2018	2017
Discount rate	4.19%	3.52%	4.30%	3.60%
Rate of increase in compensation[1]	3.00%	3.50%	n/a	n/a

[1] The Pension Plan was frozen effective January 1, 2016, and as a result, the rate of increase in compensation for participants is no longer considered an assumption used by the Company to calculate the value of the Pension Plan. As such, for the years ended December 31, 2018 and 2017, the rate of increase in compensation is only used for the

SERP.

The discount rate assumptions used by the Company represents an estimate of the interest rate at which the Pension Plan, SERP and Medical Plan obligations could effectively be settled on the measurement date.

Following are the weighted-average assumptions (weighted by the net period benefit cost for pension benefits) used by the Company in determining the net periodic Pension Plan, SERP and Medical Plan cost for the years ended December 31:

	Pension Plan and SERP benefits			Medical Plan benefits		
	2018	2017	2016	2018	2017	2016
Discount rate	3.50%	4.00%	4.23%	3.60%	4.10%	4.40%
Expected long-term return on plan assets	6.00%	6.00%	6.50%	n/a	n/a	n/a
Rate of increase in compensation[1]	3.50%	3.50%	4.00%	n/a	3.50%	4.00%

(1) The Pension Plan was frozen effective January 1, 2016, and as a result, the rate of increase in compensation for participants is no longer considered an assumption used by the Company to calculate the value of the Pension Plan. As such, for the year ended December 31, 2018, the rate of increase in compensation is only used for the SERP. For the year ended December 31, 2017, the rate of increase in compensation is only used for the SERP and Medical Plan.

In selecting the assumption for expected long-term rate of return on assets, the Company considers the average rate of return expected on the funds to be invested to provide benefits. This includes considering the plan's asset allocation, historical returns on these types of assets, the current economic environment and the expected returns likely to be earned over the life of the plan. No plan assets are expected to be returned to the Company in 2019. Historical health care cost trend rates are not applicable to the Company, because the Company's medical costs are capped at a fixed amount. As the Company's medical costs are capped at a fixed amount, the sensitivity to increases and decreases in the health-care inflation rate is not applicable.

Plan Assets

The Company's Employee Benefits Committee (EBC) oversees investment of qualified pension plan assets. The EBC uses a third-party asset manager to assist in setting targeted-policy ranges for the allocation of assets among various investment categories. The EBC allocates pension plan assets among broad asset categories and reviews the asset allocation at least annually. Asset allocation decisions consider risk and return, future-benefit requirements, participant growth and other expected cash flows. These characteristics affect the level, risk and expected growth of postretirement-benefit assets. The EBC uses asset-mix guidelines that include targets for each asset category, return objectives for each asset group and the desired level of diversification and liquidity. These guidelines may change from time to time based on the EBC's ongoing evaluation of each plan's risk tolerance. The EBC estimates an expected overall long-term rate of return on assets by weighting expected returns of each asset class by its targeted asset allocation percentage. Expected return estimates are developed from analysis of past performance and forecasts of long-term return expectations by third-parties. Responsibility for individual security selection rests with each investment manager, who is subject to guidelines specified by the EBC. The EBC sets performance objectives for each investment manager that are expected to be met over a three-year period or a complete market cycle, whichever is shorter. Performance and risk levels are regularly monitored to confirm policy compliance and that results are within expectations. Performance for each investment is measured relative to the appropriate index benchmark for its category. QEP securities may be considered for purchase at an investment manager's discretion, but within limitations prescribed by the Employee Retirement Income Security Act of 1974 (ERISA) and other laws. There was no direct investment in QEP shares for the periods disclosed. The majority of retirement-benefit assets were invested as follows:

Equity securities: Domestic equity assets were invested in a combination of index funds and actively managed products, with a diversification goal representative of the whole U.S. stock market. International equity securities consisted of developed and emerging market foreign equity assets that were invested in funds that hold a diversified portfolio of common stocks of corporations in developed and emerging foreign countries.

Debt securities: Investment grade intermediate-term debt assets are invested in funds holding a diversified portfolio of debt of governments, corporations and mortgage borrowers with average maturities of five to ten years and investment grade credit ratings. Investment grade long-term debt assets are invested in a diversified portfolio of debt of corporate and non-corporate issuers, with an average maturity of more than ten years and investment grade credit ratings. High yield and bank loan assets are held in funds holding a diversified portfolio of these instruments with an average maturity of five to seven years.

Although the actual allocation to cash and short-term investments is minimal (less than 5%), larger cash allocations may be held from time to time if deemed necessary for operational aspects of the retirement plan. Cash is invested in a high-quality, short-term temporary investment fund that purchases investment-grade quality short-term debt issued by governments and corporations.

The EBC made the decision to invest all of the retirement plan assets in commingled funds as these funds typically have lower expense ratios and are more tax efficient than mutual funds. These investments are public investment vehicles valued using the net asset value (NAV) as a practical expedient. The NAV is based on the underlying assets owned by the fund excluding transaction costs and minus liabilities, which can be traced back to observable asset values. No assets held by the Pension Plan that were valued using the NAV methodology were subject to redemption restrictions on their valuation date. These commingled funds are audited annually by an independent accounting firm. The following table summarizes investments for which fair value is measured using the NAV per share practical expedient as of December 31, 2018 and 2017, respectively:

	December 31, 2018			December 31, 2017		
	Total	Percentage of total		Total	Percentage of total	
	(in millions, except percentages)					
Cash and short-term investments	$0.7	1	%	$0.5	—	%
Equity securities:						
Domestic	20.7	22	%	35.0	35	%
International	10.0	11	%	15.3	15	%
Fixed income	61.9	66	%	49.7	50	%
Total investments	$93.3	100	%	$100.5	100	%

Expected Benefit Payments

As of December 31, 2018, the following future benefit payments are expected to be paid:

	Pension Plan and SERP benefits	Medical Plan benefits
	(in millions)	
2019	$6.6	$ 0.2
2020	$16.7	$ 0.2
2021	$6.4	$ 0.2
2022	$6.4	$ 0.2
2023	$8.1	$ 0.2
2024 through 2026	$32.7	$ 0.5

Employee Investment Plan

QEP employees may participate in the QEP Employee Investment Plan, a defined-contribution plan (401(k) Plan). The 401(k) Plan allows eligible employees to make investments, including purchasing shares of QEP common stock, through payroll deduction at the current fair market value on the transaction date. Both employees and QEP make contributions to the 401(k) Plan. The Company may contribute a discretionary portion beyond the Company's matching contribution to employees not in the Pension Plan or SERP. During the years ended December 31, 2018, 2017 and 2016, the Company made contributions of $5.8 million, $6.0 million and $5.6 million to the 401(k) Plan, respectively. The Company recognizes expense equal to its yearly contributions. Due to the Company's strategic initiatives, the amount expected to be contributed to the 401(k) Plan is subject to change. Participants receive 100% employer matching contributions on participant 401(k) plan contributions up to a percentage of qualifying earnings as described below.

Year Ended
December 31,

	2018	2017	2016
Employees who do not accrue a benefit in the SERP			
Maximum employer matching of qualifying earnings	8%	8 %	8 %
Employees who accrue a benefit in the SERP			
Maximum employer matching of qualifying earnings	6%	6 %	6 %

As a result of freezing benefits under the Pension Plan, the 401(k) Plan and a nonqualified, unfunded deferred compensation plan (the Wrap Plan), were amended to allow the Company to make discretionary contributions in the form of Company Transition Credits to eligible participants. Eligible participants are certain highly and non-highly compensated employees who were active participants in the Pension Plan on December 31, 2015. During the years ended December 31, 2018, 2017 and 2016, the Company made a discretionary contribution of $0.3 million, $0.4 million and $0.5 million, respectively, to active participants of the Pension Plan.

Note 13 – Income Taxes

On December 22, 2017 the Tax Legislation was signed into law, which resulted in significant changes to U.S. federal income tax law. QEP expects that these changes will positively impact QEP's future after-tax earnings in the U.S., primarily due to the lower federal statutory tax rate of 21% compared to 35%. The impact of the Tax Legislation may differ from the statements above due to, among other things, changes in interpretations and assumptions the Company has made and actions the Company may take as a result of the Tax Legislation. Additionally, guidance issued by the relevant regulatory authorities regarding the Tax Legislation may materially impact QEP's financial statements. As additional guidance to the Tax Legislation is published in the form of Treasury Regulations and other IRS communications, the Company will monitor, assess, and determine the impact of these communications on the Company's consolidated financial statements and operations. In addition to the Tax Legislation, QEP is continuing to monitor proposed regulations regarding the 163(j) Limitation on Deduction for Business Interest Expense, which when finalized, could require QEP to re-characterize the Company's deferred tax assets, resulting in changes in QEP's income tax disclosures. QEP expects the impact to the Company's results of operations to be immaterial.

Details of income tax provisions and deferred income taxes from continuing operations are provided in the following tables.

The components of income tax provisions and benefits were as follows:

	Year Ended December 31,		
	2018	2017	2016
Federal income tax provision (benefit)	(in millions)		
Current	$(71.3)	$2.1	$(55.5)
Deferred	(257.8)	(339.8)	(614.3)
State income tax provision (benefit)			
Current	1.5	0.5	(1.5)
Deferred	10.2	25.0	(36.9)
Total income tax provision (benefit)	$(317.4)	$(312.2)	$(708.2)

The difference between the statutory federal income tax rate and the Company's effective income tax rate is explained as follows:

	Year Ended December 31,		
	2018	2017	2016
Federal income taxes statutory rate	21.0 %	35.0 %	35.0 %
Increase (decrease) in rate as a result of:			
State income taxes, net of federal income tax benefit(1)	(0.7)%	(40.1)%	2.4 %
Federal rate change(2)	— %	741.3 %	— %
State rate change	— %	2.1 %	(1.1)%
Permanent adjustments	(0.1)%	(0.4)%	— %
Return to provision adjustment	(0.1)%	(0.7)%	— %
Uncertain tax provision (federal rate change)	— %	(7.7)%	— %

AMT Credit Reclass due to NOL Carryback(3)	3.8 %	(1.8)%	— %
Effective income tax rate	23.9 %	727.7 %	36.3 %

(1) State income taxes changed significantly from prior years mainly due to the change in valuation allowance recorded during 2017 of $36.2 million.

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(2) The Tax Legislation changed the federal corporate income tax rate from 35% to 21% starting in 2018. The rate change caused the Company to revalue its deferred tax liabilities and assets as of December 31, 2017 from a 35% to 21% federal corporate income tax rate which caused the majority of the change in rate.

(3) In 2018, QEP agreed to an IRS proposed change to the initial treatment of the 2016 carryback of net operating losses. This change resulted in a reduction of available net operating loss carryforwards valued at $75.7 million and an increase in alternative minimum tax (AMT) credit carryforwards of $126.0 million. The net change in value of $50.3 million was recorded in deferred income taxes.

Significant components of the Company's deferred income taxes were as follows:

	December 31,	
	2018	2017
Deferred tax liabilities	(in millions)	
Property, plant and equipment	$665.1	$898.7
Commodity price derivatives	30.1	—
Deferred tax assets		
Net operating loss and tax credit carryforwards	$385.6	$308.8
Employee benefits and compensation costs	26.1	26.4
Bonus and vacation accrual	7.1	6.2
Commodity price derivatives	—	29.9
Other	7.2	9.4
Total deferred tax assets	426.0	380.7
Net deferred income tax liability	$269.2	$518.0
Balance sheet classification		
Deferred income tax liability – noncurrent	269.2	518.0
Net deferred income tax liability	$269.2	$518.0

The amounts and expiration dates of net operating loss and tax credit carryforwards at December 31, 2018, are as follows:

	Expiration Dates	Amounts (in millions)
State net operating loss and tax credit carryforwards	2019-2038	$ 121.4
State net operating loss valuation allowance		$ (82.3)
U.S. net operating loss[1]	2036-2037	$ 272.3
U.S. alternative minimum tax credit	Indefinite	$ 74.2

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(1) Net operating losses created in tax years beginning after December 31, 2017 can be carried forward indefinitely under the Tax Legislation (limited to 80% of taxable income computed without the net operating loss deduction).

The valuation allowance of $82.3 million was established in 2014, 2017 and 2018 against the available state net operating loss and is related primarily to losses incurred in Oklahoma, Utah and Louisiana. Due to the 2014 property sales in the Other Southern area, in which the Company sold its interests in most of its properties in Oklahoma, the Company does not forecast sufficient taxable income to utilize the net operating loss in Oklahoma. As of December 31, 2018, $26.4 million of the allowance is related to Oklahoma net operating loss. In 2018, a valuation allowance of $49.0 million was established against Louisiana's net operating loss as the Company does not forecast sufficient taxable income to utilize the entire net operating loss in Louisiana. In 2018, a valuation allowance of $6.7 million was established against available Utah net operating losses, mainly due to the Uinta Basin Divestiture in 2018.

The Tax Legislation eliminated AMT and QEP has the ability to offset its regular tax liability or claim refunds for taxable years 2018 through 2021 for AMT credits carried forward from prior years. The Company currently anticipates it will realize approximately $148.4 million in AMT credit refunds over the next four years with $74.2 million to be realized in 2019 for tax year 2018, which is shown in "Income tax receivable" with the remaining $74.2 million included in "Deferred income taxes" on the Consolidated Balance Sheet as of December 31, 2018.

Unrecognized Tax Benefit

As of December 31, 2018 and 2017, QEP had $19.0 million of unrecognized tax benefit related to uncertain tax positions for asset sales that occurred in 2014, which were recorded within "Other long-term liabilities" on the Consolidated Balance Sheets. The $15.6 million uncertain tax position the Company reported during the year ended December 31, 2016, was expensed during the year ended December 31, 2014, with an additional $3.4 million expensed during the year ended December 31, 2017 with the Tax Legislation. The benefits of uncertain tax positions taken or expected to be taken on income tax returns is recognized in the consolidated financial statements at the largest amount that is more likely than not to be sustained upon examination by the relevant taxing authorities. Our policy is to recognize any interest expense related to uncertain tax positions in "Interest expense" on the Consolidated Statements of Operations and to recognize any penalties related to uncertain tax positions in "General and administrative" expense on the Consolidated Statements of Operations. During the years ended December 31, 2018, 2017 and 2016, the Company incurred $0.7 million of estimated interest expense related to uncertain tax positions. During the year ended December 31, 2016, the Company incurred $0.6 million of estimated penalties related to uncertain tax positions.

The following is a reconciliation of our beginning and ending amounts of unrecognized tax benefits for the years ended December 31, 2018 and 2017:

	Unrecognized Tax Benefits	
	2018	2017
	(in millions)	
Balance as of January 1,	$ 19.0	$ 15.6
Federal benefit of state (change from 35% to 21%)	—	3.4
Balance as of December 31,	$ 19.0	$ 19.0

As of December 31, 2018 and 2017, QEP had $19.0 million of unrecognized tax benefit that would impact its effective tax rate if recognized.

Note 14 – Quarterly Financial Information (unaudited)

The following table provides a summary of unaudited quarterly financial information:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2018	(in millions, except per share amounts or otherwise specified)				
Revenues	$428.9	$532.4	$ 560.8	$410.5	$1,932.6
Operating income (loss)	$21.4	$(321.8)	$ 156.8	$(1,116.8)	$(1,260.4)
Net income (loss)	$(53.6)	$(336.0)	$ 7.3	$(629.3)	$(1,011.6)
Net gain (loss) from asset sales, inclusive of restructuring costs and impairment	$2.8	$(407.6)	$ 27.1	$(1,158.2)	$(1,535.9)
Per share information					
Basic EPS	$(0.22)	$(1.42)	$ 0.03	$(2.66)	$(4.25)
Diluted EPS	$(0.22)	$(1.42)	$ 0.03	$(2.66)	$(4.25)
Production information					
Total equivalent production (Mboe)	11,724.6	14,106.1	14,400.0	11,627.2	51,857.9
2017					
Revenues	$420.1	$383.7	$390.1	$429.0	$1,622.9
Operating income (loss)	$(5.2)	$(0.9)	$132.1	$(24.5)	$101.5
Net income (loss)	$76.9	$45.4	$(3.3)	$150.3	$269.3
Net gain (loss) from asset sales and impairment	$(0.1)	$19.8	$157.1	$(42.2)	$134.6
Nonrecurring items in operating income (loss)[(1)]	$—	$—	$8.2	$—	$8.2
Per share information					
Basic EPS	$0.32	$0.19	$(0.01)	$0.62	$1.12
Diluted EPS	$0.32	$0.19	$(0.01)	$0.62	$1.12
Production information					
Total equivalent production (Mboe)	13,090.3	13,860.6	14,124.1	12,069.9	53,144.9

(1) Reflects legal expenses and loss contingencies incurred during the years ended December 31, 2017.

Note 15 – Supplemental Oil and Gas Information (unaudited)

The Company is making the following supplemental disclosures of oil and gas producing activities, in accordance with ASC 932, Extractive Activities – Oil and Gas, as amended by ASU 2010-03, Oil and Gas Reserve Estimation and Disclosures, and SEC Regulation S-X. The Company uses the successful efforts accounting method for its oil and gas exploration and development activities.

Capitalized Costs

The aggregate amounts of costs capitalized for oil and gas exploration and development activities and the related amounts of accumulated depreciation, depletion and amortization are shown below and includes capitalized costs classified as “Noncurrent assets held for sale” on the Consolidated Balance Sheets:

	December 31,	
	2018	2017
	(in millions)	
Proved properties	$12,140.7	$12,470.9
Unproved properties, net	759.1	1,095.8
Total proved and unproved properties	12,899.8	13,566.7
Accumulated depreciation, depletion and amortization	(7,450.5)	(6,642.9)
Net capitalized costs	$5,449.3	$6,923.8

Costs Incurred

The costs incurred in oil and gas acquisition, exploration and development activities are displayed in the table below. Costs associated with the Company's midstream and corporate activities are not included. Development costs are net of the change in accrued capital costs of $59.2 million and ARO additions and revisions of $0.8 million during the year ended December 31, 2018. The costs incurred for the development of reserves that were classified as proved undeveloped were approximately $606.5 million in 2018, $389.3 million in 2017 and $258.1 million in 2016.

	Year Ended December 31,		
	2018	2017	2016
	(in millions)		
Proved property acquisitions	$39.1	$269.6	$431.6
Unproved property acquisitions	25.8	532.4	208.7
Other acquisitions	0.8	13.2	—
Exploration costs (capitalized and expensed)	0.3	32.7	13.4
Development costs	1,133.1	1,189.3	509.2
Total costs incurred	$1,199.1	$2,037.2	$1,162.9

Results of Operations

Following are the results of operations of QEP's oil and gas producing activities, before allocated corporate overhead and interest expenses. Revenues and expenses relating to the Company's midstream and corporate activities are not included.

	Year Ended December 31,		
	2018	2017	2016
	(in millions)		
Revenues	$1,920.3	$1,548.1	$1,271.0
Production costs	507.3	675.4	616.7
Exploration expenses	0.3	22.0	1.7
Depreciation, depletion and amortization	836.4	735.1	852.3
Impairment	1,560.9	72.3	1,194.3
Total expenses	2,904.9	1,504.8	2,665.0
Income (loss) before income taxes	(984.6)	43.3	(1,394.0)
Income tax benefit (expense)	243.2	(16.0)	517.2
Results of operations from producing activities excluding allocated corporate overhead and interest expenses	$(741.4)	$27.3	$(876.8)

Estimated Quantities of Proved Oil and Gas Reserves

Estimates of proved oil and gas reserves have been completed in accordance with professional engineering standards and the Company's established internal controls, which include the oversight of a multi-functional Reserves Review Committee reporting to the Company's Audit Committee of the Board of Directors. The Company retained Ryder Scott Company, L.P. (RSC), independent oil and gas reserve evaluation engineering consultants, to prepare the estimates of all of its proved reserves as of December 31, 2018, 2017 and 2016. The estimated proved reserves have been prepared in accordance with the SEC's Regulation S-X and ASC 932 as amended. The individuals performing reserves estimates possess professional qualifications and demonstrate competency in reserves estimation and evaluation. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

All of QEP's proved undeveloped reserves at December 31, 2018, are scheduled to be developed within five years from the date such locations were initially disclosed as proved undeveloped reserves. The Company plans to continue development of its leaseholds and anticipates that it will have the financial capability to continue development in the manner estimated. While the majority of QEP's PUD reserves are located on leaseholds that are held by production, any PUD locations on expiring leaseholds are scheduled for development during the primary term of the lease.

As of December 31, 2018, all of the Company's oil and gas reserves are attributable to properties within the United Sates. A summary of the Company's changes in quantities of proved oil and condensate, gas and NGL reserves for the years ended December 31, 2016, 2017 and 2018 are as follows:

	Oil and condensate (MMbbl)	Gas (Bcf)	NGL (MMbbl)	Total[13] (MMboe)
Balance at December 31, 2015	193.1	2,108.9	58.8	603.4
Revisions of previous estimates[1]	(9.7)	412.8	(0.3)	58.8
Extensions and discoveries[2]	13.0	158.1	3.3	42.6
Purchase of reserves in place[3]	62.7	54.6	11.5	83.3
Sale of reserves in place[4]	(0.2)	(3.6)	(0.1)	(0.9)
Production	(20.3)	(177.0)	(6.0)	(55.8)
Balance at December 31, 2016	238.6	2,553.8	67.2	731.4
Revisions of previous estimates[5]	3.7	12.5	(3.1)	2.7
Extensions and discoveries[6]	59.1	101.9	10.4	86.4
Purchase of reserves in place[7]	46.6	125.5	8.7	76.3
Sale of reserves in place[8]	(7.9)	(831.2)	(12.6)	(159.0)
Production	(19.6)	(168.9)	(5.4)	(53.1)
Balance at December 31, 2017	320.5	1,793.6	65.2	684.7
Revisions of previous estimates[9]	2.1	314.0	6.7	61.0
Extensions and discoveries[10]	57.1	56.5	9.8	76.3
Purchase of reserves in place[11]	8.2	7.9	1.3	10.9
Sale of reserves in place[12]	(24.9)	(544.8)	(7.1)	(122.8)
Production	(23.9)	(139.6)	(4.7)	(51.9)
Balance at December 31, 2018	339.1	1,487.6	71.2	658.2
Proved developed reserves				
Balance at December 31, 2015	109.7	1,245.3	34.4	351.6
Balance at December 31, 2016	103.2	1,309.8	35.7	357.2
Balance at December 31, 2017	116.0	655.5	27.9	253.1
Balance at December 31, 2018	133.6	382.3	31.5	228.9
Proved undeveloped reserves				
Balance at December 31, 2015	83.4	863.6	24.4	251.8
Balance at December 31, 2016	135.4	1,244.0	31.5	374.2
Balance at December 31, 2017	204.5	1,138.1	37.3	431.6
Balance at December 31, 2018	205.5	1,105.3	39.7	429.3

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(1) Revisions of previous estimates in 2016 include 77.3 MMboe of positive revisions, primarily related to successful workovers in Haynesville/Cotton Valley; reserves associated with increased density wells in areas that have been previously developed on lower density spacing; and 5.5 MMboe of positive performance revisions. These positive revisions were partially offset by 18.5 MMboe of negative revisions related to pricing, driven by lower oil, gas and NGL prices.

(2) Extensions and discoveries in 2016 were primarily in the Permian and Uinta basins and related to new well completions and associated new PUD locations.

(3) Purchase of reserves in place in 2016 primarily relates to QEP's 2016 Permian Basin Acquisition as discussed in Note 3 – Acquisitions and Divestitures.

(4) Sale of reserves in place in 2016 relates to the divestiture of QEP's interest in certain non-core properties as discussed in Note 3 – Acquisitions and Divestitures.

(5) Revisions of previous estimates in 2017 include 2.7 MMboe of positive revisions, primarily related to 32.0 MMboe of positive revisions related to pricing, driven by higher oil, gas and NGL prices and 2.2 MMboe of positive performance revisions. These positive revisions were partially offset by 11.0 MMboe of negative revisions related to higher operating costs and 20.5 MMboe of other revisions primarily from changing to a horizontal development plan from a vertical well development plan in the Uinta Basin and increased longer laterals in Haynesville/Cotton Valley. These negative other revisions are partially offset by positive other revisions from successful infill drilling in Haynesville/Cotton Valley and the Williston Basin.

(6) Extensions and discoveries in 2017 primarily related to new well completions and associated new PUD locations in the Permian Basin.

(7) Purchase of reserves in place in 2017 was primarily related to QEP's 2017 Permian Basin Acquisition and various other acquired oil and gas properties as discussed in Note 3 – Acquisitions and Divestitures.

(8) Sale of reserves in place in 2018 was primarily related to QEP's Pinedale Divestiture as discussed in Note 3 – Acquisitions and Divestitures.

(9) Revisions of previous estimates in 2018 totaling 61.0 MMboe of positive revisions include 23.4 MMboe of other revisions, primarily related to changing our development plans in the Haynesville/Cotton Valley; 17.3 MMboe of positive revisions related to pricing, primarily driven by higher oil prices; 11.7 MMboe of positive revisions related to lower operating costs; and 8.7 MMboe of positive performance revisions.

(10) Extensions and discoveries in 2018 primarily related to new well completions and associated new PUD locations in the Permian Basin.

(11) Purchase of reserves in place in 2018 primarily relates to the additional acquisitions in the Permian Basin as discussed in Note 3 – Acquisitions and Divestitures.

(12) Sale of reserves in place in 2018 was primarily related to QEP's Uinta Basin Divestiture as discussed in Note 3 – Acquisitions and Divestitures.

(13) Generally, gas consumed in operations was excluded from reserves, however, in some cases, produced gas consumed in operations was included in reserves when the volumes replaced fuel purchases.

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

Future net cash flows were calculated at December 31, 2018, 2017 and 2016, by applying prices, which were the simple average of the first-of-the-month commodity prices, adjusted for location and quality differentials, for each of the 12 months during 2018, 2017 and 2016, with consideration of known contractual price changes. The prices used do not include any impact of QEP's commodity derivatives portfolio. The following table provides the average benchmark prices per unit, before location and quality differential adjustments, used to calculate the related reserve category:

	For the year ended December 31,		
	2018	2017	2016
Average benchmark price per unit:			
Oil price (per bbl)	$65.56	$51.34	$42.75
Gas price (per MMBtu)	$3.10	$2.98	$2.48

Year ended operating expenses, development costs and appropriate statutory income tax rates, with consideration of future tax rates, were used to compute the future net cash flows. All cash flows were discounted at 10% to reflect the time value of cash flows, without regard to the risk of specific properties. The estimated future costs to develop proved undeveloped reserves are approximately $620.1 million in 2019, $882.0 million in 2020 and $1,025.1 million in 2021. Estimated future development costs include capital spending on major development projects, some of which will take several years to complete. QEP believes cash flow from its operating activities, cash on hand and borrowings under its revolving credit facility will be sufficient to cover these estimated future development costs.

The assumptions used to derive the standardized measure of discounted future net cash flows are those required by accounting standards and do not necessarily reflect the Company's expectations. The information may be useful for certain comparative purposes but should not be solely relied upon in evaluating QEP or its performance. Furthermore, information contained in the following table may not represent realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company's reserves. Management believes that the following factors should be considered when reviewing the information below:

- Future commodity prices received for selling the Company's net production will likely differ from those required to be used in these calculations.
- Future operating and capital costs will likely differ from those required to be used in these calculations and do not reflect cost savings of Company owned midstream operations on future operating expenses.
- Future market conditions, government regulations, reservoir conditions and risks inherent in the production of oil and gas may cause production rates in future years to vary significantly from those rates used in the calculations.
- Future revenues may be subject to different production, severance and property taxation rates.
- The selection of a 10% discount rate is arbitrary and may not be a reasonable factor in adjusting for future economic conditions or in considering the risk that is part of realizing future net cash flows from the reserves.

The standardized measure of discounted future net cash flows relating to proved reserves is presented in the table below:

	Year Ended December 31,		
	2018	2017	2016
	(in millions)		
Future cash inflows	$26,482.6	$22,028.9	$16,239.8
Future production costs	(9,539.9)	(9,074.2)	(7,789.0)
Future development costs[1]	(4,441.5)	(4,726.0)	(3,432.9)
Future income tax expenses[2]	(2,553.6)	(1,439.1)	(913.4)
Future net cash flows	9,947.6	6,789.6	4,104.5
10% annual discount for estimated timing of net cash flows	(4,991.9)	(3,692.3)	(2,176.5)
Standardized measure of discounted future net cash flows	$4,955.7	$3,097.3	$1,928.0

(1) Future development costs include future abandonment and salvage costs.

(2) The standardized measure of discounted future net cash flows for the year ended December 31, 2018 and 2017, were estimated assuming a 21% federal tax rate from the Tax Legislation enacted in December 2017.

The principal sources of change in the standardized measure of discounted future net cash flows relating to proved reserves is presented in the table below:

	Year Ended December 31,		
	2018	2017	2016
	(in millions)		
Balance at January 1,	$3,097.3	$1,928.0	$2,476.3
Sales of oil and condensate, gas and NGL produced, net of production costs	(1,413.0)	(872.7)	(654.3)
Net change in sales prices and in production (lifting) costs related to future production	1,632.5	1,457.2	(739.4)
Net change due to extensions and discoveries	692.6	556.8	81.8
Net change due to revisions of quantity estimates	732.0	9.9	122.7
Net change due to purchases of reserves in place	117.0	342.7	256.5
Net change due to sales of reserves in place	(369.6)	(504.7)	(4.3)
Previously estimated development costs incurred during the period	735.6	475.4	374.6
Changes in estimated future development costs	(28.3)	(283.4)	(476.5)
Accretion of discount	375.4	235.7	311.1
Net change in income taxes	(615.7)	(227.4)	205.4
Other	(0.1)	(20.2)	(25.9)
Net change	1,858.4	1,169.3	(548.3)
Balance at December 31,	$4,955.7	$3,097.3	$1,928.0

Note 16 – Subsequent Events

On January 10, 2019, QEP closed its previously announced divestiture of its oil and gas assets and the gathering system in the Haynesville/Cotton Valley for net cash proceeds of $605.1 million, subject to post-closing purchase price adjustments. In addition, $32.2 million was placed in escrow due to title defects asserted prior to closing, to be resolved pursuant to the purchase and sale agreement's title dispute resolution procedures. The resolution of the asserted title defects could result in a gain or loss on sale.

On February 20, 2019, the Company agreed with the buyer to terminate the purchase and sale agreement for its assets in the Williston Basin. Following the termination of the Planned Williston Basin Divestiture, QEP will continue operating its assets in the Williston Basin, including the Company's South Antelope and Fort Berthold leaseholds. Additionally, in light of the reduction of the Company's operational footprint over the last 12 months, QEP has reassessed its organizational needs and intends to significantly reduce its general and administrative expense to ensure its cost structure is competitive with industry peers. The Company expects the majority of the organizational changes will be implemented during the first half of 2019. QEP expects to incur restructuring costs associated with contractual termination benefits including severance, accelerated vesting of share-based compensation and other expenses.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

The Company's Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the design and operation of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(b) under the Securities Exchange Act of 1934, as amended), as of December 31, 2018. Based on such evaluation, such officers have concluded that, as of December 31, 2018, the Company's disclosure controls and procedures are designed and effective to ensure that information required to be included in the Company's reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms and that information required to be disclosed in the Company's reports filed or submitted under the Exchange Act is accumulated and communicated to the Company's management including its principal executive officer and principal financial officer, or persons performing similar functions, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating the Company's disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events and the application of judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of these and other inherent limitations of control systems, there is only reasonable assurance that the Company's controls will succeed in achieving their goals under all potential future conditions.

Changes in Internal Control over Financial Reporting

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

Management's Assessment of Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rules 13a-15(f) and 15d-15(f). The Company's internal control over financial reporting is a process designed under the supervision of QEP's chief executive officer and chief financial officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted. Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Also, projections of any evaluation of the 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 processes may deteriorate.

As of December 31, 2018, management assessed the effectiveness of our internal control over financial reporting based on the criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission for effective internal control over financial reporting. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2018. Management included in its assessment of internal control over financial reporting all consolidated entities.

PricewaterhouseCoopers, LLP, the independent registered public accounting firm that audited the Consolidated Financial Statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of internal control over financial reporting as of December 31, 2018, which is included in the Consolidated Financial Statements in Item 8 of Part II of this Annual Report on Form 10-K.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by Item 10 concerning QEP's directors and nominees for directors and other corporate governance matters will be presented in the Company's definitive Proxy Statement prepared for the solicitation of proxies in connection with the Company's Annual Meeting of Stockholders, which the Company expects to file with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2018 (Proxy Statement), and is incorporated by reference herein.

Information about the Company's executive officers can be found in Item 1 of Part I in this Annual Report on Form 10-K.

Information concerning compliance with Section 16(a) of the Exchange Act will be set forth in the Proxy Statement and is incorporated herein by reference.

The Company has a Code of Conduct that applies to all of its directors, officers (including its chief executive officer and chief financial officer) and employees. QEP has posted the Code of Conduct on its website, www.qepres.com. Any waiver of the Code of Conduct for executive officers must be approved by the Company's Board of Directors. QEP will post on its website any amendments to or waivers of the Code of Conduct that apply to executive officers.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 will be set forth in the Proxy Statement and is incorporated herein by reference.

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

The information required by Item 12 will be set forth in the Proxy Statement and is incorporated herein by reference.

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

The information required by Item 13 will be set forth in the Proxy Statement and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by Item 14 will be set forth in the Proxy Statement and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial statements and financial statement schedules filed as part of this report are listed in the index included in Item 8 of Part II Financial Statements and Supplementary Data of this report.

(b) Exhibits. The following is a list of exhibits required to be filed as a part of this report in Item 15(b).

Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation dated May 15, 2018 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on May 17, 2018)

3.2	Amended and Restated Bylaws, dated effective October 23, 2017 (incorporated by reference to Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on October 25, 2017), as amended by the First Amendment to Amended and Restated Bylaws, dated effective January 11, 2019 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8 K, filed with the Securities and Exchange Commission on January 14, 2019)

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4.1	Indenture dated as of March 1, 2001, between Questar Market Resources, Inc. (predecessor-in-interest to QEP Resources, Inc.) and Bank One, NA, (predecessor-in-interest to Wells Fargo Bank, National Association), as Trustee (incorporated by reference to Exhibit 4.01 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on March 13, 2001)
4.2	6.80% Notes due 2020 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on September 2, 2009)
4.3	Officers' Certificate, dated as of August 31, 2009, setting forth the terms of the 6.80% Notes due 2020 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on September 2, 2009)
4.4	Officers' Certificate, dated as of August 16, 2010 (including the form of the 6.875% Notes due 2021) (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on August 16, 2010)
4.5	Indenture, dated as of March 1, 2012, between the Company and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on March 1, 2012)
4.6	Officer's Certificate, dated as of March 1, 2012 (including the form of the 5.375% Notes due 2022) (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on March 1, 2012)
4.7	Officer's Certificate, dated as of September 12, 2012 (including form of the 5.250% Notes due 2023) (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on September 14, 2012)
4.8	Officer's Certificate, dated as of November 21, 2017 (including the form of the 5.625% Senior Notes due 2026) (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K, filed with the Securities Exchange Commission on November 21, 2017)
10.1	Credit Agreement, dated as of August 25, 2011, among QEP Resources, Inc., Wells Fargo Bank, National Association, as the administrative agent, letter of credit issuer and swing line lender, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on August 29, 2011), as amended by the First Amendment to Credit Agreement, dated as of July 6, 2012, the Second Amendment to Credit Agreement, dated as of August 13, 2013 (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on August 16, 2013), the Third Amendment to Credit Agreement, dated as of January 31, 2014 (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on May 7, 2014), the Fourth Amendment to Credit Agreement and Commitment Increase Agreement, dated as of December 2, 2014 (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on December 4, 2014), the Fifth Amendment to Credit Agreement, dated as of November 23, 2015 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on November 23, 2015), the Sixth Amendment to Credit Agreement, dated as of May 5, 2017 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on May 9, 2017), the Seventh Amendment to Credit Agreement, dated as of November 21, 2017 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on November 27, 2017)
10.2+	Employee Matters Agreement, dated as of June 14, 2010, by and between Questar Corporation and QEP Resources, Inc. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on June 16, 2010)
10.3+	Amended and Restated QEP Resources, Inc. Deferred Compensation Wrap Plan, dated May 15, 2017 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q, filed by the Company with the Securities and Exchange Commission on July 26, 2017)
10.4+	

	Amended and Restated QEP Resources, Inc. Deferred Compensation Plan for Directors, dated July 24, 2017 (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q, filed by the Company with the Securities and Exchange Commission on July 26, 2017)
10.5+	Cash Incentive Plan, dated effective as of January 1, 2012 (incorporated by reference to Appendix A to the Company's Proxy Statement on Schedule 14A, filed with the Securities and Exchange Commission on April 3, 2012), as amended by Amendment Number One to Cash Incentive Plan, effective as of October 26, 2015 (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8 K, filed with the Securities and Exchange Commission on October 29, 2015)
10.6+	2010 Long-Term Stock Incentive Plan, adopted June 12, 2010 (incorporated by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on June 16, 2010), as amended by Amendment Number One to Long-Term Stock Incentive Plan, effective as of October 26, 2015 (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on October 29, 2015)

10.7+	2018 Long-Term Incentive Plan, as adopted on May 15, 2018 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the Company with the Securities and Exchange Commission on May 17, 2018)
10.8+	Executive Severance Compensation Plan - CIC, as Amended and Restated Effective as of October 26, 2015 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on October 29, 2015)
10.9+	Form of Indemnification Agreement for directors and officers (incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on November 5, 2013)
10.10+	Supplemental Executive Retirement Plan, effective as of January 1, 2016 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on August 3, 2015)
10.11+	Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to the CEO and CFO in 2012 and 2013 under the 2010 Long-Term Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on June 29, 2010)
10.12+	Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to executive officers other than the CEO and CFO in 2012 and 2013 under the 2010 Long-Term Stock Incentive Plan (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on June 29, 2010)
10.13+	Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to executive officers in 2014 and 2015 under the 2010 Long-Term Stock Incentive Plan (incorporated by reference to Exhibit 10.3, to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on January 23, 2014)
10.14+	Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to executive officers in 2016 and 2017 under the 2010 Long-Term Stock Incentive Plan (incorporated by reference to Exhibit 10.4, to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on October 29, 2015)
10.15+	Form of Amendment to Certain Stock Option Agreements under the QEP Resources, Inc. 2010 Long-Term Stock Incentive Plan adopted January 20, 2014 (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on January 23, 2014)
10.16+	Form of Restricted Stock Agreement for restricted stock granted to executive officers in 2016 and 2017 under the 2010 Long-Term Stock Incentive Plan (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on October 29, 2015)
10.17+	Form of Restricted Stock Agreement for restricted stock granted to executive officers in 2018 under the 2010 Long-Term Stock Incentive Plan (incorporated by reference to Exhibit 10.17 to the Annual Report on Form 10-K, filed by the Company with the Securities and Exchange Commission on February 28, 2018)
10.18+	Form of Restricted Stock Agreement for restricted stock granted to executive officers in 2019 under the 2018 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q, filed by the Company with the Securities and Exchange Commission on July 25, 2018)
10.19+	Form of Restricted Stock Agreement for restricted stock granted to non-employee directors under the 2018 Long-Term Incentive Plan
10.20+	Form of Phantom Stock Agreement for phantom stock granted to non-employee directors under the 2010 Long-Term Stock Incentive Plan (incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on June 29, 2010)
10.21+	Form of Performance Share Unit Award Agreement for performance share units granted to executive officers in 2016 under the 2012 Cash Incentive Plan (incorporated by reference to Exhibit 10.7 to the Company's Annual Report on Form 8-K, filed with the Securities and Exchange Commission on October 29, 2015)
10.22+	

	Form of Performance Share Unit Award Agreement for performance share units granted to executive officers in 2017 under the 2012 Cash Incentive Plan (incorporated by reference to Exhibit 10.33 to the Company's Annual Report on Form 10-K, filed with the Securities and Exchange Commission on February 22, 2017)
10.23+	Form of Performance Share Unit Award Agreement for performance share units granted to executive officers in 2018 under the 2012 Cash Incentive Plan (incorporated by reference to Exhibit 10.23 to the Annual Report on Form 10-K, filed by the Company with the Securities and Exchange Commission on February 28, 2018)
10.24+	Form of Performance Share Unit Award Agreement for performance share units granted to executive officers in 2019 under the 2012 Cash Incentive Plan (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q, filed by the Company with the Securities and Exchange Commission on July 25, 2018)

10.25+	Form of Deferred Share Award Agreement for shares of common stock granted to executives under the 2018 Long-Term Incentive Plan and for deferral of receipt of such shares in accordance with the terms of the Deferred Compensation Wrap Plan - Deferred Compensation Program (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q, filed by the Company with the Securities and Exchange Commission on July 25, 2018)
10.26+	Form of Severance Compensation Program Letter Agreement, dated February 26, 2018, between the Company and each of its executive officers (incorporated by reference to Exhibit 10.30 to the Annual Report on Form 10-K, filed by the Company with the Securities and Exchange Commission on February 28, 2018)
10.27+	Form of Retention Bonus Letter Agreement, dated February 26, 2018, between the Company and certain of its executive officers (incorporated by reference to Exhibit 10.29 to the Annual Report on Form 10-K, filed by the Company with the Securities and Exchange Commission on February 28, 2018)
10.28+	Form of Retention Letter, dated December 5, 2018, between the Company and certain executive officers (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the Company with the Securities and Exchange Commission on December 6, 2018)
10.29	Purchase and Sale Agreement, dated June 21, 2016, by and among QEP Energy Company, as purchaser, and RK Petroleum Corp. and various other owners of certain oil and gas properties in the Permian Basin, as sellers (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on July 27, 2016), as amended by the First Amendment to Purchase and Sale Agreement, dated as of September 7, 2016 (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on October 26, 2016), and the Second Amendment to Purchase and Sale Agreement, dated September 14, 2016 (incorporated by reference to Exhibit 1.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on September 19, 2016)
10.30	Purchase and Sale Agreement, dated July 26, 2017, by and between QEP Energy Company, as buyer, and JM Cox Resources, L.P., Alpine Oil Company, and Kelly Cox, collectively as sellers (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed by the Company with the Securities and Exchange Commission on July 26, 2017)
10.31	Purchase and Sale Agreement, dated July 24, 2017, by and between QEP Energy Company, as seller, and Pinedale Energy Partners, LLC, as buyer (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the Company with the Securities and Exchange Commission on July 25, 2017)
10.32	Purchase and Sale Agreement, dated November 6, 2018, by and among QEP Energy Company, as seller, and Vantage Acquisition Operating Company, LLC, as buyer, and Vantage Energy Acquisition Corp., as buyer's parent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the Company with the Securities and Exchange Commission on November 9, 2018)
10.33	Purchase and Sale Agreement, dated November 16, 2018, by and among QEP Energy Company, QEP Marketing Company and QEP Oil & Gas Company, collectively as seller, and Aethon III BR LLC, as buyer (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the Company with the Securities and Exchange Commission on November 20, 2018)
10.34	Letter Agreement, dated February 28, 2018, by and between QEP Resources, Inc. and Elliott Management Corporation (incorporated by reference to Exhibit 10.31 to the Annual Report on Form 10-K, filed by the Company with the Securities and Exchange Commission on February 28, 2018)
10.35*+	Letter Agreement, dated February 19, 2019, with Richard J. Doleshek
12.1*	Ratio of earnings to fixed charges
21.1*	Subsidiaries of the Company
23.1*	Consent of Independent Registered Public Accounting Firm – PricewaterhouseCoopers LLP
23.2*	Consent of Independent Petroleum Engineers and Geologists – Ryder Scott Company, L.P.
24*	Power of Attorney
31.1*	

	Certification signed by Timothy J. Cutt, QEP Resources, Inc. President and Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification signed by Richard J. Doleshek, QEP Resources, Inc. Executive Vice President, Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification signed by Timothy J. Cutt and Richard J. Doleshek, QEP Resources, Inc. President and Chief Executive Officer and Executive Vice President, Chief Financial Officer, respectively, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Qualifications and Report of Independent Petroleum Engineers and Geologists – Ryder Scott Company, L.P.
101.INS**	XBRL Instance Document
101.SCH**	XBRL Schema Document
101.CAL**	XBRL Calculation Linkbase Document

101.LAB**	XBRL Label Linkbase Document
101.PRE**	XBRL Presentation Linkbase Document
101.DEF**	XBRL Definition Linkbase Document

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* Filed herewith
** These interactive data files are furnished and deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities Act of 1934, as amended, and otherwise are not subject to liability under those sections.
+ Indicates a management contract or compensatory plan or arrangement

(c) Financial Statements Schedules: All schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or Notes thereto.

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, on February 20, 2019.

QEP RESOURCES, INC.
(Registrant)

/s/ Timothy J. Cutt
Timothy J. Cutt,
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 indicated on February 20, 2019.

/s/ Timothy J. Cutt Timothy J. Cutt	President and Chief Executive Officer (Principal Executive Officer)
/s/ Richard J. Doleshek Richard J. Doleshek	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Alice B. Ley Alice B. Ley	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)
*David Trice	Chairman of the Board; Director
*Timothy J. Cutt	Director
*Julie A. Dill	Director
*M. W. Scoggins	Director
*Mary Shafer Malicki	Director
*Michael J. Minarovic	Director
*Phillips S. Baker, Jr.	Director
*Robert F. Heinemann	Director
*William L. Thacker III	Director

February 20, 2019 *By /s/ Timothy J. Cutt
Timothy J. Cutt, Attorney in Fact