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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2019

☐ **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)

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	Trading Symbol(s)	Name of each exchange on which registered
Common stock, $0.01 par value	**QEP**	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: None

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

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (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 ☒ 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	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

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

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

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, 2019): $1,720,109,313.

At January 31, 2020, there were 237,660,873 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 2020 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 move forward as an independent company;
- plans to reduce general and administrative expenses significantly;
- restructuring costs associated with contractual termination benefits, including severance and accelerated vestings of share-based compensation;
- the effect of the strategic initiatives on employees and third parties;
- plans to generate free cash flow and focus on capital efficiency;
- 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;
- 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 generating free cash flow and capital efficiency;
- evaluation of potential acquisitions, divestitures and joint venture opportunities;
- our balance sheet and sufficient liquidity providing for the ability to meet future financial obligations, ensure financial flexibility, withstand commodity price volatility and fund its development projects, operations and capital expenditures and return capital to shareholders;
- our ability to fund maturities of senior notes;
- future availability under our revolving credit facility or continued compliance with restrictive financial covenants;
- 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;
- 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;
- 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;
- assumptions regarding share-based compensation;
- settlement of performance share units and restricted share units in cash;
- use of net operating losses; and
- alternative minimum tax credit refund amounts and timing.

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;
- 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.

Adjusted transportation and processing costs A non-GAAP financial measure which management defines as transportation and processing costs presented on the Consolidated Statements of Operations and transportation and processing costs that are included as part of "Oil and condensate, gas and NGL sales" on the Consolidated Statements of Operations. These costs are added together to reflect the total transportation and processing costs associated with QEP's production.

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 Barrel 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 cubic 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).

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.

Free Cash Flow A non-GAAP financial measure which management defines as Adjusted EBITDA plus non-cash share-based compensation less interest expense, excluding amortization of deferred finance costs, and accrued property, plant and equipment capital expenditures.

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.

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, water distribution and produced water gathering and disposal systems and related commercial activities.

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, 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 volume of PUD reserves transferred to proved developed over total volume of 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 2019
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). Unless otherwise specified or the context otherwise requires, all references to "QEP" or the "Company" are to QEP Resources, Inc. and its wholly-owned 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

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 LP (Haynesville Gathering). In January 2019, the Company closed on the sale of its Haynesville/Cotton Valley assets, including the sale of 100% of QEP's ownership of Haynesville Gathering. As a result of assigning contracts to QEP Energy, 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, 2019, QEP:

- Closed on the sale of its assets in Haynesville/Cotton Valley for net cash proceeds of $633.9 million;
- Generated a net loss of $97.3 million, or $0.41 per diluted share;
- Reported $663.6 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% decrease from 2018;
- Reported cash provided by operating activities of $566.9 million;
- Reported Free Cash Flow (a non-GAAP measure defined and reconciled in Item 7 of Part II of this Annual Report on Form 10-K) outspend of $9.8 million in 2019 compared to Free Cash Flow outspend of $314.9 million in 2018;
- Reduced general and administrative expenses by 30% compared to 2018;
- Repaid $66.9 million of senior notes, which were due in 2020 and 2021;
- Delivered record oil and condensate production of 13.5 MMbbls in the Permian Basin;
- Delivered oil equivalent production of 32.2 MMboe;
- Incurred capital expenditures (excluding property acquisitions) of $571.5 million, a 51% decrease from 2018; and
- Reported year-end total proved reserves of 382.3 MMboe, including proved crude oil and condensate reserves of 254.9 MMbbls.

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;
- remain focused on our oil basin assets;

- generate Free Cash Flow;
- return capital to shareholders;
- reduce leverage and strengthen the balance sheet;
- maintain an inventory of high return development projects in our operating areas;
- allocate capital to those projects that generate the highest returns;
- maintain 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

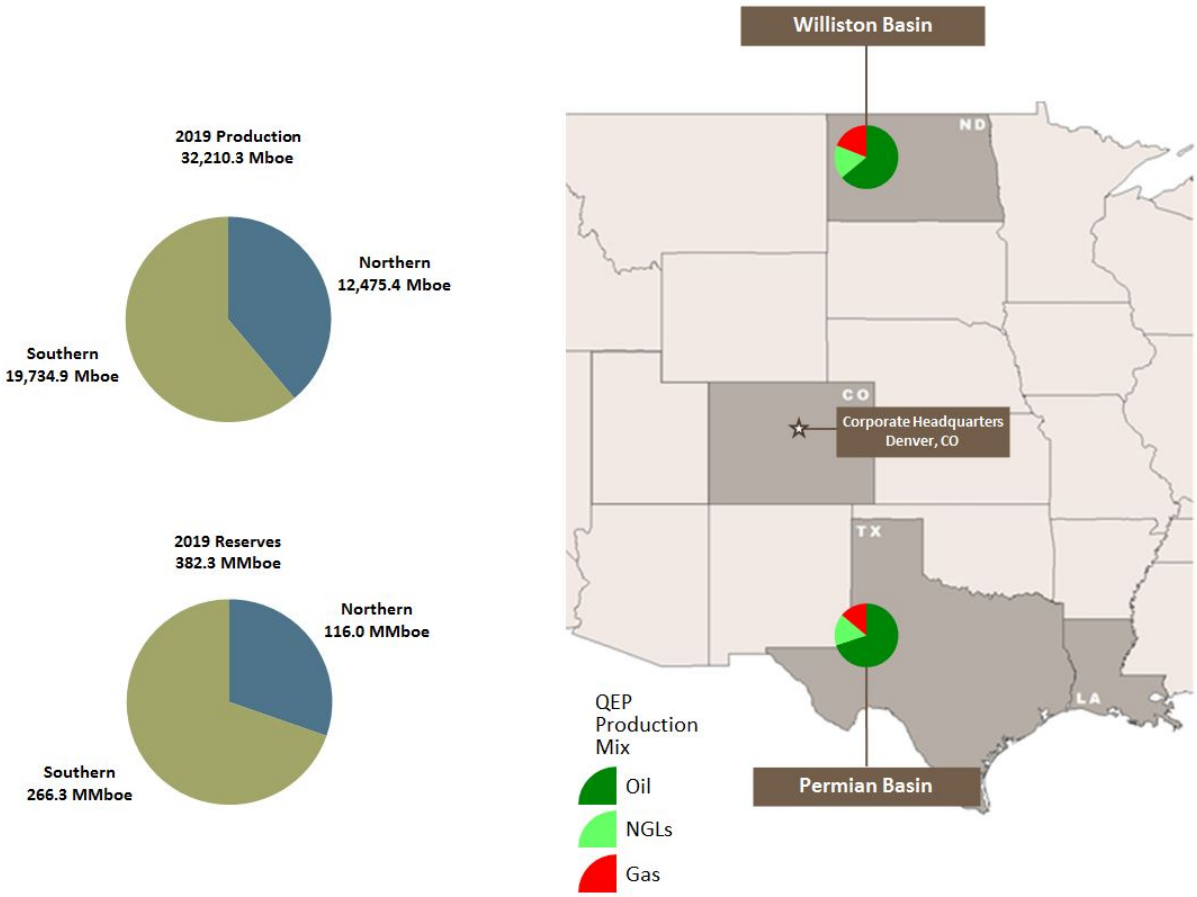
QEP conducts exploration and production (E&P) activities in two of North America's most productive hydrocarbon resource plays. For the year ended December 31, 2019, the Company reported production of over 32 MMboe, owned interests in over 378,000 gross acres, drilled 90 gross productive wells and had an extensive inventory of identifiable undeveloped drilling locations in the Permian Basin in western Texas and the Williston Basin in North Dakota.

In February 2018, QEP's Board of Directors (Board) unanimously approved certain strategic and financial 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. However, in February 2019, the Company agreed with the buyer to terminate the purchase and sale agreement (Terminated Williston Basin Divestiture).

In 2019, QEP's Board commenced and completed a comprehensive review of strategic alternatives to maximize shareholder value and determined that the best alternative for QEP's shareholders was to move forward as an independent company. Additionally, in light of the reduction of the Company's operational footprint, QEP reassessed its organizational needs and significantly reduced its general and administrative expense between 2018 and 2019 by 30% to ensure its cost structure is competitive with industry peers. QEP intends to continue to reduce its general and administrative expenses in 2020 by an additional 40% compared to 2019.

As part of the 2018 and 2019 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 9 – Restructuring in Item 8 of Part II of this Annual Report on Form 10-K for more information.

The following map illustrates the location of substantially all of the Company's operating activities, the location of its Northern and Southern Regions, and related reserve and production data during the year ended December 31, 2019:



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. 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 757.3 net productive wells, including its interest in non-operating 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. The Company utilizes a "tank-style" completion methodology and continues to test additional formations and evaluate the appropriate ultimate density of its development program. During the year ended December 31, 2019, the Company put 59 gross operated wells on production. As of December 31, 2019, QEP had two 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.

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 367.2 net productive wells, including its interest in non-operated wells, in the Williston Basin. QEP continues its development drilling program targeting the Bakken and Three Forks formations and completed seven gross operated wells during the year ended December 31, 2019. In addition, QEP began a refracturing program on operated wells in the Williston Basin in 2017, which it continued through 2019 and intends to continue in 2020.

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. Beginning in 2017, QEP sold the majority of its non-core properties in this area.

Reserves

At December 31, 2019 and 2018, QEP's estimated proved reserves were approximately 382.3 MMboe and 658.2 MMboe, respectively, of which 98% were Company operated in both years. Proved developed reserves represented 50% and 35% of the Company's total proved reserves at December 31, 2019 and 2018, 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, 2019				December 31, 2018			
	Oil and condensate	**Gas[1]**	**NGL**	**Total[1]**	Oil and condensate	Gas[1]	NGL	Total[1]
	(MMbbl)	**(Bcf)**	**(MMbbl)**	**(MMboe)[2]**	(MMbbl)	(Bcf)	(MMbbl)	(MMboe)[2]
Proved developed reserves	**117.5**	**217.0**	**36.7**	**190.4**	133.6	382.3	31.5	228.9
Proved undeveloped reserves	**137.4**	**156.3**	**28.5**	**191.9**	205.5	1,105.3	39.7	429.3
Total proved reserves	**254.9**	**373.3**	**65.2**	**382.3**	339.1	1,487.6	71.2	658.2

(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, 2017, through December 31, 2019, are summarized in the table below:

Year Ended December 31,	Year End Reserves (MMboe)	Oil and condensate, Gas and NGL Production[2][3][4] (MMboe)	Reserve Life Index[1][2][3][4] (Years)
2017	684.7	43.3	15.8
2018	658.2	49.6	13.3
2019	**382.3**	**31.9**	**12.0**

(1) Reserve life index is calculated by dividing year-end proved reserves by production for that year.
(2) The reserve life index for 2019 excludes 0.3 MMboe of production volumes from Haynesville/Cotton Valley due to the Haynesville Divestiture in January, 2019. Including production volumes from the divested Haynesville/Cotton Valley assets, the reserve life index is 11.9 years for the year ended December 31, 2019.
(3) 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.

(4) 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

Estimates of proved reserves and related information are presented in accordance 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 16 – 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,			
	2019		2018	
Northern Region	(MMboe)	(% of total)	(MMboe)	(% of total)
Williston Basin	**116.0**	**30%**	166.8	25%
Other Northern	**—**	**—%**	0.3	—%
Southern Region				
Permian Basin	**266.3**	**70%**	307.8	47%
Haynesville/Cotton Valley	**—**	**—%**	183.3	28%
Other Southern	**—**	**—%**	—	—%
Total proved reserves	**382.3**	**100%**	658.2	100%

QEP's total proved reserves as of December 31, 2019, decreased 275.9 MMboe from December 31, 2018, primarily due to the Haynesville Divestiture and a $992.2 million reduction in future estimated capital expenditures over the next five years in the Permian and Williston basins. The reduction in capital is due to the Company's change in corporate strategy in 2019 to focus on Free Cash Flow generation and capital efficiency.

Proved Undeveloped Reserves

Significant changes to PUD reserves that occurred during 2019 are summarized in the table below:

	2019
	(MMboe)
Proved undeveloped reserves at January 1,	429.3
Transferred to proved developed reserves	**(44.4)**
Revisions to previous estimates	**(94.0)**
Extensions and discoveries	**47.3**
Purchase of reserves in place	**4.9**
Sale of reserves in place	**(151.2)**
Proved undeveloped reserves at December 31,	**191.9**

Transfers to proved developed reserves. The costs incurred for the development of PUD reserves were approximately $426.1 million, $606.5 million and $389.3 million for the years ended December 31, 2019, 2018 and 2017, respectively.

QEP's planned and actual transfers of proved undeveloped reserves to proved developed reserves results for the year ended December 31, 2019 are summarized in the table below:

	Planned Transfers to Proved Developed Reserves in 2019 as of December 31, 2018 (PUD conversions)	Actual Transfers to Proved Developed Reserves in 2019 (PUD conversions)	Difference
	(MMboe)		
Northern Region			
Williston Basin	11.2	6.5	(4.7)
Other Northern	—	—	—
Southern Region			
Permian Basin	35.7	37.9	2.2
Haynesville/Cotton Valley	3.4	—	(3.4)
Other Southern	—	—	—
Total	50.3	44.4	(5.9)
Haynesville/Cotton Valley [1]	(3.4)	—	3.4
Total excluding Haynesville/Cotton Valley	46.9	44.4	(2.5)

[1] The Company had planned 3.4 MMboe of PUD reserve conversions at December 31, 2018 for Haynesville/Cotton Valley; however converted zero PUD reserves due to the Haynesville Divestiture in early January 2019.

QEP transferred 44.4 MMboe of PUD reserves to proved developed reserves in 2019 compared to 50.3 MMboe that were planned for 2019. QEP's PUD reserve conversion rate (the percentage of booked PUD reserves) was 10%, 12% and 10% for the years ended December 31, 2019, 2018 and 2017, respectively. Excluding Haynesville/Cotton Valley, QEP's PUD reserve conversion rate was 16% for the year ended December 31, 2019. At December 31, 2018, QEP's planned PUD reserve conversion rate for 2019 was 12% including Haynesville/Cotton Valley and 17% excluding Haynesville Cotton/Valley. QEP converted fewer PUD reserves than expected primarily due to reduced capital allocated to the Williston Basin as a result of the change in the Company's corporate strategy in 2019. QEP converted 9% and 18%, respectively, of the Williston and Permian basin PUD reserves in 2019.

All of QEP's proved undeveloped reserves at December 31, 2019, are scheduled to be developed within five years from the date such locations were initially disclosed as proved undeveloped reserves. In accordance with the SEC rules, 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, 2019, QEP estimates that its future development costs relating to the development of PUD reserves are approximately $435.0 million in 2020, $458.6 million in 2021 and $449.5 million in 2022. 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 2019, our PUD reserves decreased by 94.0 MMboe due to the factors summarized in the table below:

	2019
	(MMboe)
Revisions due to:	
Changes in year-end prices (price impact to January 1, 2018 balance)	**(1.8)**
Negative performance	**(8.0)**
Change in development plans	**(44.5)**
Removal due to five year SEC rule	**(25.8)**
Other	**(13.9)**
Total revisions to prior estimates	**(94.0)**

In 2019, PUD reserves were revised downward by 94.0 MMboe. The decrease was primarily due to a change in our corporate strategy in 2019 to focus on Free Cash Flow generation through a reduced capital program and a renewed focus on capital efficiency. This updated corporate strategy resulted in the removal of 44.5 MMboe of PUD reserves due to the change in the development sequence in the Permian Basin. The 44.5 MMboe reduction is offset by 47.3 MMboe of extensions and discoveries discussed below. The majority of these locations removed are economic at current prices and are technically consistent with our PUDs; however, they no longer conform to the SEC’s definition of proved reserves under the five year rule and are therefore not reported as PUDs. In addition, the reduction in the capital program over the next five years resulted in the removal of 25.8 MMboe of PUD reserves, primarily in the Williston Basin, which will no longer be developed within five years of the initial date of booking the reserves. The 8.0 MMboe negative PUD performance revisions are primarily due to updated volume projections for certain undrilled locations in the Permian Basin.

Extensions and Discoveries. Extensions and discoveries in 2019 of 47.3 MMboe were primarily related to the changes in the development sequence in the Permian Basin which is a direct result of our updated corporate strategy. These extensions and discoveries more than offset the 44.5 MMboe removal of PUD locations from the change in development plan in the Permian Basin discussed above in revisions to previous estimates.

Purchase of Reserves in Place. Purchase of reserves in place in 2019 was primarily related to the additional acquisitions in the Permian Basin 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 2019 was primarily related to the Haynesville 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 16 – 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, 2019, 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, 2019, 2018 and 2017.

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, 2019, 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 Senior Staff Corporate Reservoir Engineer. This individual is a member of the Society of Petroleum Engineers and graduated with a Bachelor of Science degree in Engineering from Missouri University of Science and Technology, and has a Master of Business Administration from the University of Texas. This individual has over 24 years of experience in the petroleum industry, including 10 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, 2019, 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 2019, 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, 2019 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 Senior Staff Corporate Reservoir Engineer. 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 Senior Staff Corporate Reservoir Engineer to RSC, including cost and pricing assumptions and reserve reconciliations from the previous reserve determinations. The Senior Staff Corporate Reservoir Engineer's 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 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 Senior Staff Corporate Reservoir Engineer 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, 2019, 2018 and 2017:

	Year Ended December 31,		
	2019	2018	2017
Production volumes			
Oil and condensate (Mbbl)	**21,558.3**	23,932.0	19,620.7
Gas (Bcf)	**33.1**	139.6	168.9
NGL (Mbbl)	**5,139.0**	4,661.4	5,367.3
Total equivalent production (Mboe)	**32,210.3**	51,857.9	53,144.9
Average field-level price [(1)]			
Oil (per bbl)	**$ 52.54**	$ 59.43	$ 47.88
Gas (per Mcf)	**$ 1.58**	$ 2.82	$ 2.92
NGL (per bbl)	**$ 11.15**	$ 23.79	$ 20.85
Production costs (per Boe)			
Lease operating expense	**$ 5.68**	$ 5.07	$ 5.55
Adjusted transportation and processing costs[(2)]	**3.22**	3.33	4.61
Production and property taxes	**2.98**	2.52	2.15
Total production costs	**$ 11.88**	$ 10.92	$ 12.31

(1) The average field-level price does not include the impact of settled commodity price derivatives or transportation and processing costs reflected as part of "Oil and condensate, gas and NGL sales" on the Consolidated Statements of Operations.

(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 Operating Expenses and Note 2 – Revenue in Items 7 and 8, respectively, 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	
	2019	2018	2017	**2019 vs 2018**	2018 vs 2017
Oil and condensate production volumes (Mbbl)					
Northern Region					
Williston Basin	**7,992.8**	11,229.5	12,353.5	**(3,236.7)**	(1,124.0)
Pinedale	**—**	—	403.8	**—**	(403.8)
Uinta Basin	**—**	447.3	656.8	**(447.3)**	(209.5)
Other Northern	**40.9**	93.2	114.2	**(52.3)**	(21.0)
Southern Region					
Permian Basin	**13,522.6**	12,137.4	6,060.9	**1,385.2**	6,076.5
Haynesville/Cotton Valley	**(0.4)**	15.6	26.5	**(16.0)**	(10.9)
Other Southern	**2.4**	9.0	5.0	**(6.6)**	4.0
Total production	**21,558.3**	23,932.0	19,620.7	**(2,373.7)**	4,311.3

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

	Year Ended December 31,			Change	
	2019	2018	2017	**2019 vs 2018**	2018 vs 2017
Gas production volumes (Bcf)					
Northern Region					
Williston Basin	**14.0**	15.6	15.5	**(1.6)**	0.1
Pinedale	**—**	—	51.9	**—**	(51.9)
Uinta Basin	**—**	10.2	16.8	**(10.2)**	(6.6)
Other Northern	**0.2**	0.9	5.7	**(0.7)**	(4.8)
Southern Region					
Permian Basin	**16.9**	10.6	6.0	**6.3**	4.6
Haynesville/Cotton Valley	**1.9**	102.2	72.9	**(100.3)**	29.3
Other Southern	**0.1**	0.1	0.1	**—**	—
Total production	**33.1**	139.6	168.9	**(106.5)**	(29.3)

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

	Year Ended December 31,			Change	
	2019	2018	2017	**2019 vs 2018**	2018 vs 2017
NGL production volumes (Mbbl)					
Northern Region					
Williston Basin	**2,073.2**	2,495.3	3,206.1	**(422.1)**	(710.8)
Pinedale	**—**	—	811.0	**—**	(811.0)
Uinta Basin	**—**	99.3	152.0	**(99.3)**	(52.7)
Other Northern	**1.8**	10.5	13.4	**(8.7)**	(2.9)
Southern Region					
Permian Basin	**3,062.7**	2,054.4	1,168.5	**1,008.3**	885.9
Haynesville/Cotton Valley	**—**	0.5	16.2	**(0.5)**	(15.7)
Other Southern	**1.3**	1.4	0.1	**(0.1)**	1.3
Total production	**5,139.0**	4,661.4	5,367.3	**477.6**	(705.9)

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

	Year Ended December 31,			Change	
	2019	2018	2017	**2019 vs 2018**	2018 vs 2017
Total production volumes (Mboe)					
Northern Region					
Williston Basin	**12,403.8**	16,331.3	18,140.0	**(3,927.5)**	(1,808.7)
Pinedale	**—**	—	9,871.7	**—**	(9,871.7)
Uinta Basin	**—**	2,243.5	3,605.4	**(2,243.5)**	(1,361.9)
Other Northern	**71.6**	247.1	1,082.4	**(175.5)**	(835.3)
Southern Region					
Permian Basin	**19,406.6**	15,960.3	8,227.2	**3,446.3**	7,733.1
Haynesville/Cotton Valley	**310.5**	17,050.5	12,188.7	**(16,740.0)**	4,861.8
Other Southern	**17.8**	25.2	29.5	**(7.4)**	(4.3)
Total production	**32,210.3**	51,857.9	53,144.9	**(19,647.6)**	(1,287.0)

A regional comparison of average field-level prices (excluding the impact of settled commodity price derivatives or transportation and processing costs reflected as part of "Oil and condensate, gas and NGL sales" on the Consolidated Statements of Operations) and average production costs (excluding production and property taxes) per Boe is shown in the following table:

	Year Ended December 31,			Change	
	2019	2018	2017	**2019 vs 2018**	2018 vs 2017
Average field-level oil price (per bbl)					
Northern Region	**$ 52.52**	$ 62.63	$ 47.24	**$ (10.11)**	$ 15.39
Southern Region	**$ 52.55**	$ 56.34	$ 49.30	**$ (3.79)**	$ 7.04
Average field-level oil price	**$ 52.54**	$ 59.43	$ 47.88	**$ (6.89)**	$ 11.55
Average field-level gas price (per Mcf)					
Northern Region	**$ 2.36**	$ 2.71	$ 2.93	**$ (0.35)**	$ (0.22)
Southern Region	**$ 1.00**	$ 2.84	$ 2.92	**$ (1.84)**	$ (0.08)
Average field-level gas price	**$ 1.58**	$ 2.82	$ 2.92	**$ (1.24)**	$ (0.10)
Average field-level NGL price (per bbl)					
Northern Region	**$ 9.37**	$ 23.56	$ 21.41	**$ (14.19)**	$ 2.15
Southern Region	**$ 12.36**	$ 24.09	$ 18.87	**$ (11.73)**	$ 5.22
Average field-level NGL price	**$ 11.15**	$ 23.79	$ 20.85	**$ (12.64)**	$ 2.94
Lease operating and adjusted transportation and processing costs (per Boe)					
Northern Region	**$ 13.70**	$ 12.90	$ 11.24	**$ 0.80**	$ 1.66
Southern Region	**$ 7.55**	$ 5.82	$ 8.43	**$ 1.73**	$ (2.61)
Adjusted average lease operating and transportation and processing costs	**$ 8.90**	$ 8.40	$ 10.16	**$ 0.50**	$ (1.76)

Northern Region

Williston Basin

Production volumes decreased 24% to 12,403.8 Mboe during 2019 compared to 2018, primarily as a result of reduced capital expenditures in 2019 in order to focus on generating Free Cash Flow and natural production decline, partially offset by seven new operated well completions and two refractured operated wells, which were put on production in the fourth quarter of 2019.

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.

During the years ended December 31, 2019, 2018 and 2017, Williston Basin production represented 39%, 31% and 34%, 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 years ended December 31, 2019 and 2018.

During the year ended December 31, 2017, Pinedale production represented 19% of QEP's total equivalent production.

Uinta Basin
Due to the divestiture of the Uinta Basin properties in September 2018, there was no production during the year ended December 31, 2019.

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.

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

Other Northern
Production volumes decreased 71% and 77% during the years ended December 31, 2019 and 2018, respectively, primarily due to the continued divestiture of properties during 2019 and 2018.

During the years ended December 31, 2019, and 2018, Other Northern production represented less than 1% of QEP's total equivalent production. During the year ended December 31, 2017, Other Northern production represented 2% of QEP's total equivalent production.

Southern Region

Permian Basin
Production volumes increased 22% and 94% during the years ended December 31, 2019 and 2018, respectively, primarily as a result of continued horizontal development activities in the Spraberry Shale and Wolfcamp formations. The 2019 production volume increase was smaller than the 2018 increase due to the reduction in capital expenditures in 2019 in order to focus on generating Free Cash Flow.

During the years ended December 31, 2019, 2018 and 2017, Permian Basin production represented 60%, 31%, and 15% respectively, of QEP's total equivalent production.

Haynesville/Cotton Valley
Production volumes decreased 98% to 310.5 Mboe during 2019 compared to 2018, due to the divestiture of the Haynesville/Cotton Valley properties in January 2019.

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.

During the years ended December 31, 2019, 2018 and 2017, Haynesville/Cotton Valley's production represented 1%, 34% and 23%, respectively, of QEP's total equivalent production.

Other Southern
Production volumes decreased 29% and 15% during the years ended December 31, 2019 and 2018, respectively, due to the continued divestiture of properties.

During the years ended December 31, 2019, 2018 and 2017, 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, 2019, all of which are located in the U.S.:

	Oil		Gas		Total[2]	
	Gross	Net	Gross	Net	Gross	Net
Northern Region						
Williston Basin	729	367.2	—	—	729	367.2
Other Northern	—	—	—	—	—	—
Southern Region						
Permian Basin	797	757.3	—	—	797	757.3
Haynesville/Cotton Valley[1]	—	—	—	—	—	—
Other Southern	—	—	3	0.1	3	0.1
Total productive wells	1,526	1,124.5	3	0.1	1,529	1,124.6

(1) As a result of the Haynesville Divestiture, QEP no longer owns operated or non-operated productive wells in Haynesville/Cotton Valley as of December 31, 2019. Refer to Note 3 – Acquisitions and Divestitures in Item 8 of Part II of this Annual Report on Form 10-K for more information.

(2) These totals represent productive wells as of December 31, 2019, primarily in our core operating areas of the Williston and Permian basins. In addition to the table above, QEP has interests, primarily overriding royal interests, in a number of wells outside of our core areas that have minimal revenues and reserves.

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, 2019. "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
North Dakota	77,894	61,804	34,535	32,804	112,429	94,608
Texas	49,991	39,223	17,899	15,351	67,890	54,574
Idaho	—	—	44,175	10,643	44,175	10,643
Oregon	—	—	43,869	7,671	43,869	7,671
Other	39,253	18,063	70,391	25,564	109,644	43,627
Total	167,138	119,090	210,869	92,033	378,007	211,123

(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,		
2020	680	417
2021	480	450
2022	—	—
2023	—	—
2024 and later	—	—
Total	1,160	867

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, 2019								
Northern Region								
Williston Basin	**26**	**8.4**	**—**	**—**	**—**	**—**	**—**	**—**
Other Northern	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Southern Region								
Permian Basin	**64**	**59.3**	**—**	**—**	**—**	**—**	**—**	**—**
Haynesville/Cotton Valley	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Other Southern	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Total	**90**	**67.7**	**—**	**—**	**—**	**—**	**—**	**—**
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	—	—

The following table presents operated and non-operated wells in the process of being drilled or waiting on completion as of December 31, 2019:

		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	—	—	—	—	—	—	—	15	0.2
Other Northern	—	—	—	—	—	—	—	—	—
Southern Region									
Permian Basin[1]	2	13	13.0	45	42.8	—	—	—	—
Other Southern	—	—	—	—	—	—	—	—	—

(1) The number of gross operated drilling wells in the Permian Basin includes 12 wells for which surface casing has been set as of December 31, 2019.

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.

The following table presents the number of operated wells in the process of being drilled or waiting on completion at December 31, 2019:

	Permian Basin		Williston Basin	
	December 31, 2019			
	Gross	Net	Gross	Net
Well Progress				
Drilling	13	13.0	—	—
At total depth - under drilling rig	1	1.0	—	—
Waiting to be completed	35	33.4	—	—
Undergoing completion	5	4.7	—	—
Completed, awaiting production	4	3.7	—	—
Waiting on completion	45	42.8	—	—

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, 2019:

	Operated Put on Production		Non-operated Put on Production	
	Year Ended December 31, 2019			
	Gross	Net	Gross	Net
Northern Region				
Williston Basin	7	6.4	19	2.0
Other Northern	—	—	—	—
Southern Region				
Permian Basin	59	58.9	5	0.4
Other Southern	—	—	—	—

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)[1]
2020	17.4
Thereafter	52.4

[1] Includes delivery commitments related to future obligations in an area in which the Company no longer has production operations. During the year ended December 31, 2019, the Company recognized $7.7 million of firm transportation expense related to the future obligations in this area.

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 its term sales commitments or that it can purchase sufficient volumes of oil and condensate or gas in the market at index-related prices to satisfy its sales commitments. The Company has incurred shortfalls related to some of its gathering and firm transportation commitments and as a result paid contractual cash obligations of $8.3 million, $13.4 million and $40.4 million for the years ended December 31, 2019, 2018 and 2017, 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, 2019, 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 66%, 49% and 59%, in the aggregate, of QEP's revenues for the years ended December 31, 2019, 2018 and 2017, 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, 2019	
Occidental Energy Marketing	**21%**
Valero Marketing & Supply Company	**18%**
Plains Marketing LP	**17%**

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%

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, 2019 and 2018, QEP had 248 and 465 employees, respectively. None of QEP's employees are represented by unions or covered by collective bargaining agreements.

Information about our Executive Officers

The name, age, period of service, title and business experience of each of QEP's executive officers as of February 14, 2020, are listed below:

Timothy J. Cutt	59	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).
Christopher K. Woosley	50	Executive Vice President, General Counsel and Corporate Secretary (January 2020 to present). Senior Vice President and General Counsel (2017 to 2019). 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).
William J. Buese	48	Vice President, Chief Financial Officer and Treasurer (January 2020 to present). Vice President Finance and Treasurer (2014-2019). Director of Finance (2012-2014). Prior to joining QEP, Mr. Buese was Director, Finance at MarkWest Energy Partners, LP, and served in various finance, treasury, accounting and investor relations roles (2005-2012). Prior to joining MarkWest, Mr. Buese was employed in a non-energy-related industry for more than 10 years.
Joseph T. Redman	42	Vice President, Energy (2019 to present). Vice President, Western Region (2017 to 2019). 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, Mr. Redman 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 Board of 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. 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. In August 2019, the EPA proposed two options for further revising its methane regulations. Under the EPA's preferred alternative, the agency would rescind the methane limits for new, reconstructed and modified oil and natural gas production sources while leaving in place the general emission limits for volatile organic compounds (VOCs), and relieve the EPA of its obligation to develop guidelines for methane emissions from existing sources. In addition, the proposal would remove from the oil and natural gas category the natural gas transmission and storage segment. The other proposed alternative would rescind the methane requirements applicable to all oil and natural gas sources, without removing any sources from that source category (and still requiring control of VOCs in general). 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. Many states and local governments are undertaking efforts to meet climate goals which could restrict development of oil and gas as well as lessen demand depending on the specific initiatives. Foreign governments' pursuit of climate change goals could also impact demand and reduce prices on U.S. oil and natural gas.

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 has been the subject of litigation and related administrative matters since the EPA and the U.S. Army Corps of Engineers (Corps) in 2015 proposed to revise and expand the definition of WOTUS (2015 Rule). However, in October 2019, the EPA and the Corps published a final rule repealing the 2015 Rule and re-codifying the longstanding and familiar regulatory text that existed prior to the 2015 Rule. In January 2020 a new WOTUS rule was finalized which replaced the 2015 rule. Under the final rule, the following four categories of waters would be defined as WOTUS: traditional navigable waters and territorial seas; perennial and intermittent tributaries to those waters; lakes, ponds and impoundments of jurisdictional waters; and wetlands adjacent to jurisdictional waters. Additional litigation and administrative proceedings are expected in the future. 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 concluded in 2019 that they did not need to regulate "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of oil, gas or geothermal energy" after they reviewed the RCRA regulations for exploration and production waste. The EPA concluded that states were adequately regulating exploration and production waste under the subsection “D” provision of RCRA. The subsection “D” provision that provides for EPA exemption and provides for state management of said waste is reviewable by the EPA every three years.

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 transports 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 (CEQ) and other agency regulations, usually for the BLM in the areas where QEP operates. In January 2020, the CEQ announced a notice of proposed rulemaking to update procedural provisions and modernization of NEPA.

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 or foreign 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 operates one crude oil pipeline 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. However, we may incur additional compliance costs if PHMSA adopts new pipeline safety regulations in the future. For instance, in October 2019, PHMSA submitted three major rules to the Federal Register, including rules focused on: the safety of gas transmission pipelines (the first of three parts of the so-called PHMSA gas “Mega Rule”); the safety of hazardous liquid pipelines; and enhanced emergency order procedures. PHMSA is expected to issue the second part of the gas Mega Rule in mid-2020, and the final part of the gas Mega Rule in late-2020 or early-2021.

Transporting Crude Oil by Rail. QEP sells crude oil to customers that may transport crude oil by rail. In 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.

Crude Oil Export. The Consolidated Appropriations Act of 2016 (HR 2029) included a provision to end the export ban on domestic crude oil. The Consolidated Appropriations Act of 2016 (HR 2029) passed both houses of Congress and was signed by President Obama in 2015. While QEP does not export crude oil, any restrictions by Congress or the President to limit crude oil exports could reduce domestic prices received by QEP.

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. Natural gas flaring in Texas has increased over the past years and the TRRC may implement regulations or restrictions on flaring of natural gas which could increase production costs to QEP or restrict production of crude oil.

North Dakota. The North Dakota Industrial Commission (NDI Commission), North Dakota's chief energy regulator, issued an order in 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.

Substantially all of our producing properties and operations are located in the Williston Basin and Permian Basin, making us vulnerable to risks associated with operating in a limited number of 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. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as the Williston Basin and Permian Basin, which may cause these conditions to occur with greater frequency or magnify the effect of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

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;
- including events in the Middle East, Africa, South America and Russia;
- the strength of the U.S. dollar relative to other currencies;
- weather conditions, natural disasters and epidemic or pandemic disasters such as the coronavirus;
- domestic and international laws, regulations and taxes, including regulations, legislation or executive orders relating to climate change, induced seismicity or oil and gas exploration and production activities, including, but not limited to hydraulic fracturing;
- 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, gas and NGL prices would not only reduce revenue, but could also reduce the amount of oil, gas and NGL that we can economically produce and therefore potentially lower our oil and gas reserve quantities. In addition, a decline in oil and gas prices and volatility could negatively impact our ability to execute our operating and development plans and the ability to generate Free Cash Flow.

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;
- limit QEP's ability to generate Free Cash Flow;
- 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 year ended December 31, 2019, there were no impairments on its oil and gas related properties. During the years ended December 31, 2018 and 2017, QEP recorded impairment charges of $1,524.6 million and $38.1 million, respectively, on its proved properties and $36.3 million and $29.0 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, 2018 and goodwill impairment of $5.3 million during the year ended December 31, 2017. 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, 2019 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.

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 2019 and 2018, QEP removed 25.8 MMboe and 22.6 MMboe, respectively, of PUD reserves that were no longer in the 2019 and 2018 forecasted capital expenditure plans, respectively, and would not be drilled and completed within five years of the initial date of booking of the reserves. The majority of the 2019 PUD write-downs were due to a change in our development plan from the implementation of a new strategy of capital efficiency and Free Cash Flow generation. There is no assurance that we may not change our development plan again in the future, resulting in further write-downs. At December 31, 2019, approximately 50% 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 $2.2 billion during the five years ending December 31, 2024. 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.

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 over the past several 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;
- fires, 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;
- delays imposed by or resulting from legal proceedings;
- 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;
- flaring of natural gas, including, where required, accurate and timely payment of royalty on flared gas;
- 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 as 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.

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 or unconventional wells are not achieving production expectations, 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. As of December 31, 2019, QEP operates 98% of its net productive oil and natural gas wells. 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 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, processing 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, the commencement of production from new wells, and may negatively affect the production from existing offset wells, all of which may cause volatility in QEP's operating results from period to period. This may lead to additional volatility in QEP's operating results. For example, QEP experienced delays in placing certain wells in the Permian Basin into production during 2017 due to the evolution of its “tank-style” completion methodology, which caused shifts in completion timing. Finally, 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, proximity 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 and gas processing arrangements, third-party systems may be temporarily unavailable due to market conditions, mechanical failures, accidents, lack of contracted capacity on such systems 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, gas flaring increased, or production shut-in, each of which could reduce profitability. The curtailments arising from these circumstances may last from a few days to several months, and in many cases, QEP is provided with limited, if any, notice as to when these circumstances will arise and their duration. Furthermore, if QEP were required to shut-in wells, it might also be obligated to pay certain demand charges for gathering and processing services, 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 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 in paying quantities is established and maintained 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. Under the terms of certain of our leases and the laws in the states in which we operate, production from our wells must be maintained in paying quantities. If we fail to maintain certain levels of production or otherwise fail to comply with the terms of our leases (e.g. paying royalties in a timely and correct manner), it is possible for us to lose our leases.

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 future development 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 and recycling 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. Substantially all of QEP’s production depends on the availability of gathering, transportation, gas processing, or storage facilities owned and operated by midstream service providers under agreements which expire periodically. If QEP agrees to renew or extend 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 under which QEP is obligated to pay certain fees on minimum volumes regardless of actual volume throughput. As of December 31, 2019, QEP's aggregate long-term contractual obligation under these agreements was $81.2 million. These fees could be significant and may have a material adverse effect on QEP's results of operations.

QEP is partially 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 to meet short-term funding needs. At year end 2019, QEP had no outstanding 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, not having sufficient liquidity to meet future financial obligations 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 $2.0 billion at December 31, 2019. 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 pay dividends, 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 governing 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 10 – 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. 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 10 – 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. Our failure to fund capital expenditures may delay or prevent the development of our properties, which may adversely impact our ability to retain leaseholds that are held by production, increase lease expirations, and decrease production and reserves from our properties.

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.

Changes in LIBOR reporting practices or the method in which LIBOR is determined may adversely affect the market value of QEP's current or future debt obligations, including QEP's revolving credit facility. The interest rate in QEP's revolving credit facility is indexed to the London Interbank Offered Rate (LIBOR). On July 27, 2017, the Financial Conduct Authority (the FCA) announced its intention to phase out LIBOR rates by the end of 2021. It is unclear whether LIBOR will cease to exist or if new methods of calculating LIBOR will be established such that it continues to exist after 2021, or whether any alternative reference rate will attain market acceptance as a replacement for LIBOR. It is not possible to predict the further effect of the rules of the FCA, any changes in the methods by which LIBOR is determined or any other reforms to LIBOR that may be enacted in the United Kingdom, the European Union or elsewhere. Any such developments may cause LIBOR to perform differently than in the past, or cease to exist. In addition, any other legal or regulatory changes made by the FCA, the European Commission or any other successor governance or oversight body, or future changes adopted by such body, in the method by which LIBOR is determined or the change from LIBOR to a successor benchmark may result in, among other things, a sudden or prolonged increase or decrease in LIBOR, a delay in the publication of LIBOR, and changes in the rules or methodologies in LIBOR, which may discourage market participants from continuing to administer or to participate in LIBOR's determination, and, in certain situations, could result in LIBOR no longer being determined and published. If a published U.S. dollar LIBOR rate is unavailable after 2021, the interest rates on our debt which are indexed to LIBOR will be determined using an alternative method, which may result in interest obligations which are more than or do not otherwise correlate over time with the payments that would have been made on such debt if U.S. dollar LIBOR was available in its current form. Further, the same costs and risks that may lead to the discontinuation or unavailability of U.S. dollar LIBOR may make one or more of the alternative methods impossible or impracticable to determine. Any of these proposals or consequences could have a material adverse effect on our financing costs. As of February 14, 2020, we had no outstanding borrowings under our revolving credit facility.

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.

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 United States. 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;
- bans on hydraulic fracturing;
- bans on crude oil and natural gas exports;
- restrictions on installation or operation of gathering, processing or pipeline facilities;
- restrictions on flaring of natural gas;
- 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. 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, business combinations and divestiture 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. Over the past several years, QEP has relied on proceeds from asset divestitures to help fund acquisitions, make capital expenditures and to repay debt. 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 assets 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 (pending or threatened) 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.

QEP complies with numerous environmental regulations including the Clear Air Act and Clean Water Act. Refer to Items 1 & 2 of Part I Government Regulations of this Annual Report on Form 10-K for additional detail on these regulations.

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 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. The NDI Commission is undergoing new efforts to further reduce the flaring in North Dakota, which could trigger a new rulemaking in 2020. It is possible that other states in which QEP operates, including Texas, will require gas capture plans or otherwise institute new regulatory requirements

in the future to reduce flaring.

Additionally, in November 2016, the 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. If our interpretation of the applicable regulations is incorrect, or if we receive a non-appealable order to pay royalty on past and future flared volumes in North Dakota, such royalty payments could materially and adversely affect our financial condition 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.

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. Lessees and operators conducting operations on tribal lands may be 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 and local level, some states and local governments have adopted, and other states and local governments 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. Water is an essential component of QEP’s drilling and hydraulic fracture stimulation processes. 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. In recent years, West Texas has experienced a severe drought. Accordingly, QEP may experience difficulty in securing the necessary volumes of water for its operations. QEP's inability to timely 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 oil and 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 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.

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 Democratic 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 August 2019, and the prospects for legal challenges to such revisions. Additionally, in 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 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 November 2019, President Trump initiated the formal process to withdraw the United States from the Paris Agreement with an effective withdrawal date of November 2020. 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.

A change in the jurisdictional characterization of some of our assets by federal, state, or local regulatory agencies or a change in policy by those agencies could result in increased regulation of our assets, which could cause our revenues to decline and operating expenses to increase. We believe that our gas gathering systems meet the traditional tests FERC has used to determine if a pipeline is a gas gathering pipeline and is, therefore, not subject to FERC jurisdiction. FERC, however, has not made any determinations with respect to the jurisdictional status of any of these gas gathering systems. The distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of ongoing litigation and, over time, FERC policy concerning which activities it regulates and which activities are excluded from its regulation has changed. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation.

In addition, 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 or foreign 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.

FERC makes jurisdictional determinations for both natural gas gathering and crude oil lines on a case-by-case basis. The classification and regulation of our pipelines are subject to change based on future determinations by FERC, the courts, or Congress. A change in the jurisdictional characterization of some of our assets by federal, state, or local regulatory agencies or a change in policy by those agencies could result in increased regulation of our assets, which could cause our revenues to decline and operating expenses to increase.

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 or impact the refundability of U.S. alternative minimum tax credits we currently expect to receive over the next three years. 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 NOL's arising prior to the ownership change could be limited, possibly substantially. Additionally, the deductibility of disallowed interest expense carryforward, pursuant to the Tax Cuts and Jobs Act enacted in December 2017 (Tax Legislation), 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 NOL's, 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 successful completion of the Uinta Basin Divestiture and the Haynesville Divestiture, as well as its initiative to significantly reduce its general and administrative expense to ensure that it is competitive with its industry peers, QEP experienced a reduction in headcount in 2018 and 2019. Additionally, in 2019, QEP's President and Chief Executive Officer, its Executive Vice President of operations, and its Executive Vice President and Chief Financial Officer, each of whom had a long tenure with the Company, departed the Company. The loss of services from any of these reductions 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 four active and suspended participants, or 2%, of QEP's active employees and 210 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, 2019 and 2018, it is estimated that QEP's pension plans were underfunded by $21.3 million and $28.8 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 $5.5 million and $5.7 million during the years ended December 31, 2019 and 2018, respectively, to the Pension Plan and SERP and expects to make contributions of approximately $12.6 million to these pension plans in 2020. 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 and its vendors have 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;
- the inability of QEP shareholders who own less than 25% or more of outstanding shares of QEP’s common stock to call special meetings; and
- the inability of QEP shareholders to 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.

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. Shareholders may from time to time attempt to effect changes, engage in proxy solicitations or advance shareholder proposals. Activist shareholders may make strategic proposals, suggestions or requested changes concerning our operations, strategy, management, assets or other matters. For example, in response to a January 2019 proposal from Elliott Management Corporation to acquire all shares of our common stock, our Board of Directors engaged in a comprehensive review of strategic alternatives and concluded that the best alternative for QEP’s shareholders was to move forward as an independent company. Responding to additional 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 long-term value from our assets.

The Company's ability to declare and pay dividends is subject to certain considerations. Dividends are authorized and determined by the Company's Board of Directors in its sole discretion. Decisions regarding the payment of dividends are subject to a number of considerations, including:

- cash available for distribution;
- the Company's results of operations and anticipated future results of operations;

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

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

We may be unable to quickly adapt to changes in market/investor priorities. Historically, one of the key drivers in the unconventional resource industry has been growth in production and reserves. With the continued downturn and volatility in oil and natural gas prices, and the possibility that interest rates will rise in the near term, increasing the cost of borrowing, the market and investor emphasis has elevated capital efficiency and free cash flow from earnings as potentially the key drivers for energy companies, especially those primarily focused in the shale play arena. Shifts in focus such as these sometimes require changes in planning and resource management, which cannot necessarily occur instantaneously. Any delay in responding to such changes in market sentiment or perception can result in the investment community in general having a negative sentiment regarding our business plan, potential profitability and our ability to operate in a manner deemed “efficient,” which can have a negative impact on the price of 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 currently issues 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 matter below is disclosed pursuant to the first requirement.

The Mabee Ranch Royalty Partnership, LP, et al. v. QEP Energy Company – In October 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 11 – 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, 2020, QEP had 4,849 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 2019, QEP changed its performance measurement to compare to an index that includes a large group of its peers to align with the industry and provide a broader comparison of stock price performance.

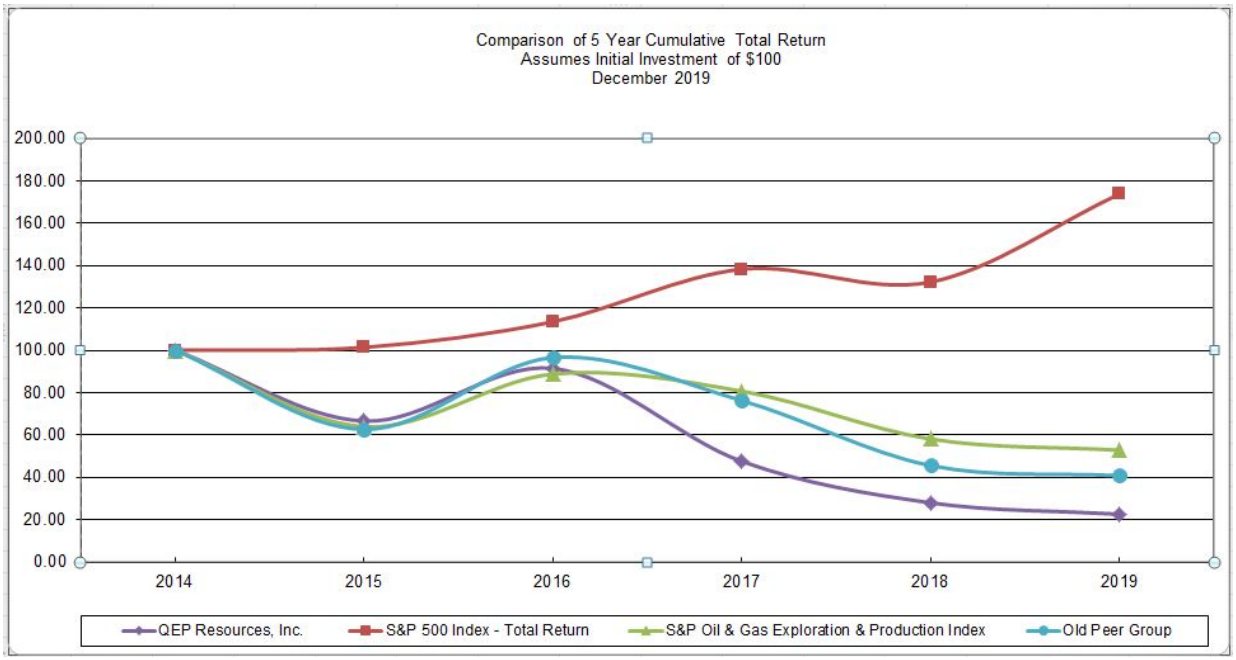
QEP's previous peer group, as defined, consisted of the following companies:

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	

After the change in peer companies, QEP's 2019 peer group consists of the companies included in the S&P Oil & Gas Exploration & Production Index.

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, the Company's old peer group and the S&P Oil & Gas Exploration & Production Index as of December 31, 2014, and its relative performance is tracked through December 31, 2019;
- 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 and reinstated its quarterly dividend in August 2019.



	2014	2015	2016	2017	2018	2019
QEP Resources, Inc.	$ 100.00	$ 66.58	$ 91.48	$ 47.55	$ 27.97	$ 22.60
S&P 500 Index – Total Returns	$ 100.00	$ 101.38	$ 113.51	$ 138.29	$ 132.23	$ 173.86
New Peer Group	$ 100.00	$ 63.95	$ 88.77	$ 80.72	$ 58.10	$ 52.79
Old Peer Group	$ 100.00	$ 62.67	$ 96.56	$ 76.27	$ 45.55	$ 40.76

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 repurchases of shares during the three months ended December 31, 2019 were in connection with the settlement of income tax and related benefit withholding obligations arising from the vesting of restricted share grants. As of December 31, 2019, the remaining value that may be purchased under the share repurchase program was $1,191.6 million.

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data for the five years ended December 31, 2019, is provided in the table below. QEP's financial results for the years ended December 31, 2016 and 2015 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). 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,				
	2019[1]	2018[1]	2017[1]	2016 [1]	2015
Statement of Operations Data	(in millions, except per share amounts)				
Revenues[2][3]	**$ 1,206.2**	$ 1,932.6	$ 1,622.9	$ 1,377.1	$ 2,018.6
Operating income (loss)[4]	**$ 157.5**	$ (1,260.4)	$ 101.5	$ (1,600.7)	$ (364.5)
Net income (loss)[5]	**$ (97.3)**	$ (1,011.6)	$ 269.3	$ (1,245.0)	$ (149.4)
Earnings (loss) per common share					
Basic	**$ (0.41)**	$ (4.25)	$ 1.12	$ (5.62)	$ (0.85)
Diluted	**(0.41)**	(4.25)	1.12	(5.62)	(0.85)
Weighted-average common shares outstanding					
Used in basic calculation	**237.7**	237.9	240.6	221.7	176.6
Used in diluted calculation	**237.7**	237.9	240.6	221.7	176.6
Dividends per common share	**$ 0.04**	$ —	$ —	$ —	$ 0.08
Balance Sheet Data					
Total Assets at December 31,[6]	**$ 5,477.8**	$ 6,117.8	$ 7,394.8	$ 7,245.4	$ 8,398.2
Capitalization at December 31,					
Long-term debt	**$ 2,015.6**	$ 2,507.1	$ 2,160.8	$ 2,020.9	$ 2,191.5
Total equity	**2,660.6**	2,750.9	3,797.9	3,502.7	3,947.9
Total Capitalization	**$ 4,676.2**	$ 5,258.0	$ 5,958.7	$ 5,523.6	$ 6,139.4
Statement of Cash Flows Data					
Net cash provided by (used in) operating activities[7]	**$ 566.9**	$ 816.2	$ 600.2	$ 667.2	$ 498.5
Capital expenditures	**$ (566.2)**	$ (1,299.7)	$ (1,974.8)	$ (1,208.1)	$ (1,239.4)
Net cash provided by (used in) investing activities	**$ 112.7**	$ (1,056.1)	$ (1,168.0)	$ (1,179.1)	$ (1,217.6)
Net cash provided by (used in) financing activities	**$ (511.3)**	$ 244.6	$ 125.8	$ 583.1	$ (47.7)
Non-GAAP Measures					
Adjusted EBITDA[4][8]	**$ 663.6**	$ 974.8	$ 736.1	$ 628.1	$ 1,031.2
Free Cash Flow[9]	**$ (9.8)**	$ (314.9)	$ (588.4)	$ (12.8)	$ (91.6)

(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 years ended December 31, 2019 and 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 and 2015. 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 13 – Employee Benefits in Item 8 of Part II of this Annual Report on Form 10-K for more information.

(5) 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.

(6) On January 1, 2019, QEP adopted ASU No. 2016-02, *Leases (Topic 842)*, using the modified retrospective approach. During the year ended December 31, 2019, total assets are impacted by the adoption of this ASU. Refer to Note 8 – Leases in Item 8 of Part II of this Annual Report on Form 10-K for more information

(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 and 2015. 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.

(9) Free Cash Flow is a non-GAAP financial measure. Management defines Free Cash Flow as Adjusted EBITDA plus non-cash share-based compensation less interest expense, excluding amortization of debt issuance costs and discounts, and accrued property, plant and equipment capital expenditures. Management believes that this measure is useful to management and investors for analysis of the Company's ability to pay dividends, repay debt, fund acquisitions or repurchase stock. 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 Free Cash Flow.

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,				
	2019	2018	2017	2016	2015
	(in millions)				
Net income (loss)	**$ (97.3)**	$ (1,011.6)	$ 269.3	$ (1,245.0)	$ (149.4)
Interest expense	**128.1**	149.4	137.8	143.2	145.6
Interest and other (income) expense[1]	**(4.7)**	9.6	(1.6)	(23.7)	10.1
Income tax provision (benefit)	**(43.0)**	(317.4)	(312.2)	(708.2)	(93.6)
Depreciation, depletion and amortization	**540.0**	857.1	754.5	871.1	881.1
Unrealized (gains) losses on derivative contracts	**138.3**	(248.5)	(40.0)	367.0	183.7
Exploration expenses	**0.1**	0.3	22.0	1.7	2.7
Net (gain) loss from asset sales, inclusive of restructuring costs	**(3.9)**	(25.0)	(213.5)	(5.0)	(4.6)
Impairment	**5.0**	1,560.9	78.9	1,194.3	55.6
Loss from early extinguishment of debt	**1.0**	—	32.7	—	—
Other[1][2]	**—**	—	8.2	32.7	—
Adjusted EBITDA	**$ 663.6**	$ 974.8	$ 736.1	$ 628.1	$ 1,031.2

(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 and 2015. 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 13 – 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.

The following table reconciles QEP's Net Cash Provided by (Used in) Operating Activities (a GAAP measure) to Free Cash Flow. 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,				
	2019	2018	2017	2016	2015
Cash Flow Information:					
Net Cash Provided by (Used in) Operating Activities[1]	**$ 566.9**	$ 816.2	$ 600.2	$ 667.2	$ 498.5
Net Cash Provided by (Used in) Investing Activities	**112.7**	(1,056.1)	(1,168.0)	(1,179.1)	(1,217.6)
Net Cash Provided by (Used in) Financing Activities	**(511.3)**	244.6	125.8	583.1	(47.7)
Free Cash Flow					
Net Cash Provided by (Used in) Operating Activities	**$ 566.9**	$ 816.2	$ 600.2	$ 667.2	$ 498.5
Exploration expense	**0.1**	0.3	22.0	1.7	2.7
Amortization of debt issuance costs and discounts	**(5.4)**	(5.4)	(6.2)	(6.4)	(6.2)
Interest expense	**128.1**	149.4	137.8	143.2	145.6
Unrealized (gains) losses on marketable securities	**3.9**	(1.2)	2.9	1.4	(0.2)
Interest and other income (expense)[2]	**(4.7)**	9.6	(1.6)	(23.7)	10.1
Deferred income taxes (benefit)	**(4.3)**	247.6	314.8	651.3	(25.3)
Income tax (provision) benefit	**(43.0)**	(317.4)	(312.2)	(708.2)	(93.6)
Non-cash share-based compensation	**(20.8)**	(30.9)	(26.9)	(26.0)	(28.5)
Dry hole exploratory well expense	**—**	—	(21.3)	—	—
Other EBITDA adjustments[2][3]	**—**	—	8.2	32.7	—
Bargain purchase gain from acquisitions	**—**	—	(0.4)	22.6	—
Pension curtailment loss[2]	**—**	—	—	—	(11.2)
Other non-cash activity	**—**	—	9.4	—	—
Changes in operating assets and liabilities	**42.8**	106.6	9.4	(127.7)	539.3
Adjusted EBITDA	**663.6**	974.8	736.1	628.1	1,031.2
Non-cash share-based compensation	**20.8**	30.9	26.9	26.0	28.5
Interest expense, excluding amortization of debt issuance costs and discounts	**(122.7)**	(144.0)	(131.6)	(136.8)	(139.4)
Accrued property, plant and equipment capital expenditures	**(571.5)**	(1,176.6)	(1,219.8)	(530.1)	(1,011.9)
Free Cash Flow	**$ (9.8)**	$ (314.9)	$ (588.4)	$ (12.8)	$ (91.6)

(1) 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 and 2015. 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.

(2) 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", "Other EBITDA adjustments" and "Pension curtailment loss" for the years ended December 31, 2016 and 2015. 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 13 – Employee Benefits in Item 8 of Part II of this Annual Report on Form 10-K for more information.

(3) 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 2018 Annual Report on Form 10-K filing, and analyzes the changes in the results of operations between the years ended December 31, 2019 and 2018. Refer to Item 7 of Part II of the 2018 Annual Report on Form 10-K filing for discussion and analysis of the changes in results of operations between the years ended December 31, 2018 and 2017.

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). 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 2019, QEP's Board commenced and completed a comprehensive review of strategic alternatives to maximize shareholder value and determined that the best alternative for QEP's shareholders was to move forward as an independent company. Additionally, in light of the reduction of the Company's operational footprint, QEP reassessed its organizational needs and significantly reduced its general and administrative expense between 2018 and 2019 by 30% to ensure its cost structure is competitive with industry peers. QEP intends to continue to reduce its general and administrative expenses in 2020 by an additional 40% compared to 2019.

As a part of the 2018 and 2019 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 9 – Restructuring in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Acquisitions and Divestitures

While QEP's strategy is to generate Free Cash Flow, and believes its inventory of identified drilling locations provides a solid base to achieve its strategy, it will continue to evaluate and potentially acquire properties in its operating areas to add additional development opportunities and facilitate the drilling of long lateral wells.

Acquisitions

During the year ended December 31, 2019 and 2018, QEP acquired various oil and gas properties, which primarily included proved leasehold acreage in the Permian Basin for an aggregate purchase price of $3.5 million and $16.5 million, respectively, subject to post-closing purchase price adjustments.

In the fourth quarter of 2017, QEP acquired various oil and gas properties, which primarily included proved leasehold acreage in the Permian Basin for an aggregate purchase price of $721.0 million (2017 Permian Basin Acquisition). The 2017 Permian Basin Acquisition consisted of approximately 15,100 acres, mainly in Martin County, Texas, which were held by production from vertical wells.

In addition, 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.

Divestitures

In January 2019, QEP closed the sale of its assets in Haynesville/Cotton Valley (Haynesville Divestiture) and in July 2019 reached final settlement on asserted title defects. QEP received net cash proceeds of $633.9 million from the Haynesville Divestiture, during the year ended December 31, 2019. In addition, the purchaser agreed to assume QEP's obligations associated with firm transportation agreements related to the Haynesville/Cotton Valley assets, which as of December 31, 2018, totaled $195.4 million. During the years ended December 31, 2019 and 2018, QEP recorded a pre-tax loss, including restructuring costs, of $1.0 million and $3.0 million, respectively, which were recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations. 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 addition to the Haynesville Divestiture, during the year ended December 31, 2019, QEP received net cash proceeds of $45.0 million and recorded a net pre-tax gain on sale of $4.9 million primarily related to the divestiture of properties outside its main operating areas.

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 by the buyer's shareholders and regulatory approvals. In February 2019, the Company agreed with the buyer to terminate the purchase and sale agreement (Terminated Williston Basin Divestiture). 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 (Uinta Basin Divestiture). In addition, during the years ended December 31, 2019 and 2018, QEP recorded a pre-tax loss of $0.2 million and $12.6 million, respectively, which were recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations. 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 9 – Restructuring 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 9 – Restructuring in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Financial and Operating Highlights

During the year ended December 31, 2019, QEP:

- Closed on the sale of its assets in Haynesville/Cotton Valley for net cash proceeds of $633.9 million;
- Generated a net loss of $97.3 million, or $0.41 per diluted share;
- Reported $663.6 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% decrease from 2018;
- Reported cash provided by operating activities of $566.9 million;
- Reported Free Cash Flow (a non-GAAP measure defined and reconciled in Item 7 of Part II of this Annual Report on Form 10-K) outspend of $9.8 million in 2019 compared to Free Cash Flow outspend of $314.9 million in 2018;
- Reduced general and administrative expenses by 30% compared to 2018;
- Repaid $66.9 million of senior notes, which were due in 2020 and 2021;
- Delivered record oil and condensate production of 13.5 MMbbls in the Permian Basin;
- Delivered oil equivalent production of 32.2 MMboe;
- Incurred capital expenditures (excluding property acquisitions) of $571.5 million, a 51% decrease from 2018; and
- Reported year-end total proved reserves of 382.3 MMboe, including proved crude oil and condensate reserves of 254.9 MMbbls.

Outlook

The Company continues to focus on reducing its operating costs, per well drilling costs, general and administrative costs and managing its liquidity. We believe our plan to generate Free Cash Flow on an annual basis will allow us to further strengthen our balance sheet and continue returning capital to shareholders.

Based on current commodity prices, we expect to be able to fund our planned capital program for 2020 with cash flow from operating activities, cash on hand and, if needed, borrowings under our credit facility. Our total capital expenditures (excluding property acquisitions), for 2020 are expected to be approximately $570.0 million. 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

Strategic Initiatives

During 2019, we continued to pursue several strategic initiatives to maximize shareholder value. Organizational modifications due to these strategic initiatives 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, during 2019, we incurred significant general and administrative expense, including transaction costs, retention bonuses and severance payments, in connection with the strategic initiatives. Refer to Note 9 – Restructuring in Item 8 of Part II of this Annual Report on Form 10-K for more information.

QEP's producing properties are primarily 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 factors such 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.

Shareholder Activism
Shareholders may from time to time attempt to effect changes, engage in proxy solicitations or advance shareholder proposals. Activist shareholders may make strategic proposals, suggestions or requested changes concerning our operations, strategy, management, assets or other matters. For example, in response to a January 2019 proposal from Elliott Management Corporation to acquire all shares of our common stock, our Board of Directors engaged in a comprehensive review of strategic alternatives and concluded that the best alternative for QEP's shareholders was to move forward as an independent company. Responding to additional 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 long-term value from our assets.

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 has 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 $77.41 per barrel in June 2018. The NYMEX HH spot market price of natural gas has ranged from a low of $1.49 per MMBtu in March 2016 to a high of $6.24 per MMBtu in January 2018. 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; the impact of regulations and public and financial market sentiment regarding climate change; 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 and condensate, 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, 2019, QEP forecasted the midpoint of its 2020 annual oil and condensate production to be approximately 21.9 MMbbl and had approximately 76% of its forecasted oil and condensate production covered with fixed-price swaps. 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 and operating lease right-of-use assets 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. 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.

During the year ended December 31, 2019, the Company recorded impairments of $5.0 million related to an office building lease. During the year ended December 31, 2018, impairments were $1,560.9 million primarily due to impairments of proved and unproved properties as a result of signing purchase and sale agreements for the Terminated 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. 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, 2019 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.

Income Tax

In December 2017 the Tax Legislation was signed into law, which resulted in significant changes to U.S. federal income tax law. The Tax Legislation reduced our federal corporate tax rate from 35% to 21%. In addition, the Tax Legislation eliminated corporate AMT which allowed QEP 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 received $73.9 million of AMT credit refunds in 2019 and anticipates it will realize approximately $74.6 million in AMT credit refunds over the next three years with $37.5 million to be realized in 2020 for tax years 2018 and 2019, which is shown in "Income tax receivable" with the remaining $37.1 million included in "Deferred income taxes" on the Consolidated Balance Sheet as of December 31, 2019.

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 and condensate 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. Because 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, multi-well pad drilling delays the completion of wells, the commencement of production from new wells, and may negatively affect production from existing offset wells. 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 the timing of 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 11 – 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, 2019 of $97.3 million, or $0.41 per diluted share, compared to net loss of $1,011.6 million, or $4.25 per diluted share, in 2018. The decrease in net loss for the year ended December 31, 2019, compared to the year ended December 31, 2018, was primarily due to a decrease in impairment expense of $1,555.9 million.

See below for additional discussion regarding the components of net income (loss) for the years ended December 31, 2019 and 2018.

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,		
	2019	2018	2017
	(in millions)		
Net income (loss)	**$ (97.3)**	$ (1,011.6)	$ 269.3
Interest expense	**128.1**	149.4	137.8
Interest and other (income) expense	**(4.7)**	9.6	(1.6)
Income tax provision (benefit)	**(43.0)**	(317.4)	(312.2)
Depreciation, depletion and amortization	**540.0**	857.1	754.5
Unrealized (gains) losses on derivative contracts	**138.3**	(248.5)	(40.0)
Exploration expenses	**0.1**	0.3	22.0
Net (gain) loss from asset sales, inclusive of restructuring costs	**(3.9)**	(25.0)	(213.5)
Impairment	**5.0**	1,560.9	78.9
Loss from early extinguishment of debt	**1.0**	—	32.7
Other[(1)]	**—**	—	8.2
Adjusted EBITDA	**$ 663.6**	$ 974.8	$ 736.1

(1) Reflects legal expenses and loss contingencies incurred during the year ended December 31, 2017. 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 decreased to $663.6 million during the year ended December 31, 2019, compared to $974.8 million in 2018, primarily due to the Haynesville/Cotton Valley and Uinta Basin divestitures, a 24% decrease in equivalent production in the Williston Basin, a 12% decrease in average field-level oil prices, and a 53% decrease in average field-level NGL prices; partially offset by a 22% increase in equivalent production in the Permian Basin, a $123.0 million decrease in realized derivative losses, a $65.9 million decrease in general and administrative expenses and a 20% reduction in lease operating expenses in the Williston Basin.

Free Cash Flow (Non-GAAP)

Management defines Free Cash Flow as Adjusted EBITDA plus non-cash share-based compensation less interest expense, excluding amortization of debt issuance costs and discounts, and accrued property, plant and equipment capital expenditures. Management believes that this measure is useful to management and investors for analysis of the Company's ability to pay dividends, repay debt, fund acquisitions or repurchase stock.

Below is a reconciliation of Net Cash Provided by (Used in) Operating Activities (the most comparable GAAP measure) to Free Cash Flow. 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,		
	2019	2018	2017
Cash Flow Information:			
Net Cash Provided by (Used in) Operating Activities	**$ 566.9**	$ 816.2	$ 600.2
Net Cash Provided by (Used in) Investing Activities	**112.7**	(1,056.1)	(1,168.0)
Net Cash Provided by (Used in) Financing Activities	**(511.3)**	244.6	125.8
Free Cash Flow			
Net Cash Provided by (Used in) Operating Activities	**$ 566.9**	$ 816.2	$ 600.2
Exploration expense	**0.1**	0.3	22.0
Amortization of debt issuance costs and discounts	**(5.4)**	(5.4)	(6.2)
Interest expense	**128.1**	149.4	137.8
Unrealized (gains) losses on marketable securities	**3.9**	(1.2)	2.9
Interest and other income (expense)	**(4.7)**	9.6	(1.6)
Deferred income taxes (benefit)	**(4.3)**	247.6	314.8
Income tax (provision) benefit	**(43.0)**	(317.4)	(312.2)
Non-cash share-based compensation	**(20.8)**	(30.9)	(26.9)
Dry hole exploratory well expense	**—**	—	(21.3)
Other EBITDA adjustments[1]	**—**	—	8.2
Bargain purchase gain from acquisitions	**—**	—	(0.4)
Other non-cash activity	**—**	—	9.4
Changes in operating assets and liabilities	**42.8**	106.6	9.4
Adjusted EBITDA	**663.6**	974.8	736.1
Non-cash share-based compensation	**20.8**	30.9	26.9
Interest expense, excluding amortization of debt issuance costs and discounts	**(122.7)**	(144.0)	(131.6)
Accrued property, plant and equipment capital expenditures	**(571.5)**	(1,176.6)	(1,219.8)
Free Cash Flow	**$ (9.8)**	$ (314.9)	$ (588.4)

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

QEP had Free Cash Flow outspend of $9.8 million during the year ended December 31, 2019, compared to an outspend of $314.9 million during 2018. The reduction in the amount of the Company's outspend is primarily due to the Company's strategy to reduce capital expenditures and focus on generating Free Cash Flow. See above for additional discussion regarding the components of the change in Adjusted EBITDA in 2019 compared to 2018.

Revenue

The following table presents our revenues disaggregated by revenue source.

	Year Ended December 31,			Change	
	2019	2018	2017[1]	**2019 vs 2018**	2018 vs 2017
			(in millions)		
Oil and condensate, gas and NGL sales, as presented	**$ 1,187.4**	$ 1,871.3	$ 1,545.3	**$ (683.9)**	$ 326.0
Transportation and processing costs in revenue[2]	**54.9**	55.0	—	**(0.1)**	55.0
Oil and condensate, gas and NGL sales, as adjusted[3]	**$ 1,242.3**	$ 1,926.3	$ 1,545.3	**$ (684.0)**	381.0
Oil and condensate sales	**$ 1,132.6**	$ 1,422.4	$ 939.4	**$ (289.8)**	$ 483.0
Gas sales	**52.4**	393.0	494.0	**(340.6)**	(101.0)
NGL sales	**57.3**	110.9	111.9	**(53.6)**	(1.0)
Oil and condensate, gas and NGL sales, as adjusted[3]	**$ 1,242.3**	$ 1,926.3	$ 1,545.3	**$ (684.0)**	381.0

(1) Amounts for the year ended December 31, 2017 have not been adjusted under the modified retrospective method for the new revenue recognition rule, ASC Topic 606. 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 years ended December 31, 2019 and 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, 2019 compared to the years ended December 31, 2018 and 2017:

	Oil and condensate	Gas	NGL	Total
Oil and condensate, gas and NGL sales, as adjusted	(in millions)			
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
Changes associated with volumes[1]	**(141.0)**	**(300.3)**	**11.4**	**(429.9)**
Changes associated with prices[2]	**(148.8)**	**(40.3)**	**(65.0)**	**(254.1)**
Year ended December 31, 2019	**$ 1,132.6**	**$ 52.4**	**$ 57.3**	**$ 1,242.3**

(1) The revenue variance attributed to the change in volume is calculated by multiplying the change in volumes from the years ended December 31, 2019 and 2018, as compared to the years ended December 31, 2018 and 2017, by the average field-level price for the years ended December 31, 2018 and 2017, 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, 2019 and 2018, as compared to the years ended December 31, 2018 and 2017, by the respective volumes for the years ended December 31, 2019 and 2018, 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, but excluding transportation and processing costs reflected as part of "Oil and condensate, gas and NGL sales" on the Consolidated Statements of Operations, is provided in the following table:

	Year Ended December 31,			Change	
	2019	2018	2017	**2019 vs 2018**	2018 vs 2017
Oil (per bbl)					
Average field-level price	**$ 52.54**	$ 59.43	$ 47.88	**$ (6.89)**	$ 11.55
Commodity derivative impact	**(1.50)**	(6.41)	0.34	**4.91**	(6.75)
Net realized price	**$ 51.04**	$ 53.02	$ 48.22	**$ (1.98)**	$ 4.80
Gas (per Mcf)					
Average field-level price	**$ 1.58**	$ 2.82	$ 2.92	**$ (1.24)**	$ (0.10)
Commodity derivative impact	**(0.08)**	(0.04)	(0.13)	**(0.04)**	0.09
Net realized price	**$ 1.50**	$ 2.78	$ 2.79	**$ (1.28)**	$ (0.01)
NGL (per bbl)					
Average field-level price	**$ 11.15**	$ 23.79	$ 20.85	**$ (12.64)**	$ 2.94
Commodity derivative impact	**—**	—	—	**—**	—
Net realized price	**$ 11.15**	$ 23.79	$ 20.85	**$ (12.64)**	$ 2.94
Average net equivalent price (per Boe)					
Average field-level price	**$ 38.57**	$ 37.15	$ 29.08	**$ 1.42**	$ 8.07
Commodity derivative impact	**(1.09)**	(3.06)	(0.29)	**1.97**	(2.77)
Net realized price	**$ 37.48**	$ 34.09	$ 28.79	**$ 3.39**	$ 5.30

Oil and condensate sales. Oil and condensate sales were $1,132.6 million for the year ended December 31, 2019, a decrease of $289.8 million, or 20%, compared to 2018. This decrease was a result of an 12% decrease in average field-level prices and a 10% decrease in oil and condensate production volumes. The decrease in average field-level oil prices was driven by a decrease in average NYMEX WTI oil prices for the comparable period, partially offset by a $1.21 per bbl, or 21% decrease, in the basis differential relative to the average NYMEX WTI oil price in 2019 compared to 2018. The 10% decrease in oil and condensate production volumes was primarily driven by a 29% decrease in production in the Williston Basin due to a reduced level of drilling completion activity in 2019 and the Uinta Basin Divestiture, partially offset by an 11% increase in production in the Permian Basin due to continued drilling and completion activity.

Gas sales. Gas sales were $52.4 million for the year ended December 31, 2019, a decrease of $340.6 million, or 87%, compared to 2018. This decrease was a result of a 76% decrease in gas production volumes and a 44% decrease in average field-level prices. The 76% decrease in production volumes was primarily due to the Haynesville/Cotton Valley and Uinta Basin divestitures, partially offset by an increase in production in the Permian Basin due to continued drilling and completion activity. The decrease in average field-level gas prices was driven by a decrease in average NYMEX-HH natural gas spot prices and a $0.77 per Mcf, or 286% increase, in the regional basis differential relative to the average NYMEX-HH gas price in 2019 compared to 2018.

NGL sales. NGL sales were $57.3 million for the year ended December 31, 2019, a decrease of $53.6 million, or 48%, compared to 2018. This decrease was primarily a result of a 53% decrease in average field-level prices, partially offset by a 10% increase in NGL production volumes. The 53% decrease in average field-level prices was primarily driven by a decrease in propane, ethane and other NGL component prices. The 10% increase in NGL production volumes was primarily driven by continued drilling and completion activity and higher gas capture rates as a result of the completion of our midstream infrastructure in the Permian Basin, partially offset by production decreases in the Williston Basin due to a reduced level of drilling and completion activity in 2019 and the Uinta Basin Divestiture.

Resale Margin and Storage Activity

QEP purchases and resells oil and gas primarily to mitigate losses on marketing commitments and historically 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	
	2019	2018	2017	**2019 vs 2018**	2018 vs 2017
	(in millions)				
Purchased oil and gas sales	**$ 10.9**	$ 48.8	$ 62.6	**$ (37.9)**	$ (13.8)
Purchased oil and gas expense	**(11.0)**	(51.0)	(64.3)	**40.0**	13.3
Realized gains (losses) on gas storage derivative contracts	**—**	0.3	—	**(0.3)**	0.3
Resale margin	**$ (0.1)**	$ (1.9)	$ (1.7)	**$ 1.8**	$ (0.2)

Purchased oil and gas sales and expense decreased during the year ended December 31, 2019, compared to the year ended December 31, 2018, primarily due to the fulfillment of a gas sales agreement related to Pinedale that was retained and not part of the Pinedale Divestiture, and fulfillment of our firm volume commitments in Haynesville/Cotton Valley, which were divested in January 2019.

Operating Expenses

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

	Year Ended December 31,			Change	
	2019	2018	2017	**2019 vs 2018**	2018 vs 2017
	(in millions)				
Lease operating expense	**$ 182.9**	$ 263.1	$ 294.8	**$ (80.2)**	$ (31.7)
Adjusted transportation and processing costs[1]	**$ 103.6**	$ 172.6	245.3	**(69.0)**	(72.7)
Production and property taxes	**95.9**	130.8	114.3	**(34.9)**	16.5
Total production costs	**$ 382.4**	$ 566.5	$ 654.4	**$ (184.1)**	$ (87.9)
	(per Boe)				
Lease operating expense	**$ 5.68**	$ 5.07	$ 5.55	**$ 0.61**	$ (0.48)
Adjusted transportation and processing costs[1]	**3.22**	3.33	4.61	**(0.11)**	(1.28)
Production and property taxes	**2.98**	2.52	2.15	**0.46**	0.37
Total production costs	**$ 11.88**	$ 10.92	$ 12.31	**$ 0.96**	$ (1.39)

(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	
	2019	2018	2017[1]	**2019 vs 2018**	2018 vs 2017
	(in millions)				
Transportation and processing costs, as presented	**$ 48.7**	$ 117.6	$ 245.3	**$ (68.9)**	$ (127.7)
Transportation and processing costs deducted from oil and condensate, gas and NGL sales	**54.9**	55.0	—	**(0.1)**	55.0
Adjusted transportation and processing costs	**$ 103.6**	$ 172.6	$ 245.3	**$ (69.0)**	$ (72.7)
	(per Boe)				
Transportation and processing costs, as presented	**$ 1.51**	$ 2.27	$ 4.61	**$ (0.76)**	$ (2.34)
Transportation and processing costs deducted from oil and condensate, gas and NGL sales	**1.70**	1.06	—	**0.64**	1.06
Adjusted transportation and processing costs	**$ 3.21**	$ 3.33	$ 4.61	**$ (0.12)**	$ (1.28)

(1) Amounts for the year ended December 31, 2017 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.

Lease operating expense (LOE). QEP's LOE decreased $80.2 million during the year ended December 31, 2019 compared to 2018. The decrease in expense was driven by the Haynesville/Cotton Valley and Uinta Basin 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. Excluding those divestitures, LOE decreased $28.3 million, driven by a decrease in maintenance and repair expenses, labor, water disposal, and workovers in the Williston Basin as a result of lower production and continuing efforts to reduce operating expenses.

During the year ended December 31, 2019, LOE increased $0.61 per Boe, or 12%, compared to the year ended December 31, 2018, but was down 12% excluding the Haynesville/Cotton Valley and Uinta Basin divestitures. The 12% per BOE decrease was related to lower cost production from the recent horizontal well completions in the Permian Basin, partially offset by decreased production in the Williston Basin.

Adjusted transportation and processing costs. QEP's adjusted transportation and processing costs decreased $69.0 million during the year ended December 31, 2019 compared to 2018. The decrease in expense during 2019 was primarily attributable to the Haynesville/Cotton Valley and Uinta Basin divestitures. Excluding those divestitures, adjusted transportation and processing costs increased $0.6 million, primarily due to the recognition of $7.7 million of firm transportation expense related to future obligations in an area in which the Company no longer has production operations and increased production in the Permian Basin, partially offset by decreased production in the Williston Basin.

During the year ended December 31, 2019, adjusted transportation and processing costs decreased $0.11 per Boe, or 3%, compared to the year ended December 31, 2018. The decrease was primarily due to the Haynesville/Cotton Valley and Uinta Basin divestitures, which had higher adjusted transportation and processing costs per Boe. Excluding the Haynesville/Cotton Valley and Uinta Basin divestitures, adjusted transportation and processing costs per Boe were up 3% due to the recognition of $7.7 million of firm transportation expense related to future obligations in areas in which the Company no longer has production operations.

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 decreased $34.9 million during 2019, primarily due to decreased revenues in the Williston Basin as well as the Haynesville/Cotton Valley and Uinta Basin divestitures.

During the year ended December 31, 2019, production and property taxes increased $0.46 per Boe, or 18%, compared to the year ended December 31, 2018, but decreased 14% excluding the Haynesville/Cotton Valley and Uinta Basin divestitures. The 14% decrease was due to a decrease in average field-level equivalent prices in the Permian and Williston basins, partially offset by higher ad valorem charges per Boe in the Permian Basin.

Depreciation, depletion and amortization (DD&A). DD&A expense decreased $317.1 million during the year ended December 31, 2019, compared to 2018. The decrease was primarily due to a lower DD&A rate and decreased production in the Williston Basin, as well as the Haynesville/Cotton Valley and Uinta Basin divestitures. The decreased DD&A rate was driven by a 2018 impairment of proved and unproved properties in the Williston Basin. This decrease was partially offset by increased DD&A in the Permian Basin due to increased volumes and a slightly higher DD&A rate.

Impairment expense. During the year ended December 31, 2019, QEP recorded impairment charges of $5.0 million, compared to $1,560.9 million of impairment charges recorded during 2018. The $5.0 million of impairment charges recorded during 2019 related to the impairment of an office building lease. 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.

General and administrative (G&A) expense. During 2019, G&A expense decreased $65.9 million, or 30%, compared to 2018. During the years ended December 31, 2019 and 2018, QEP incurred $50.1 million and $61.0 million, respectively, in costs associated with the implementation of our strategic initiatives, of which $43.4 million and $54.3 million, respectively, was related to restructuring costs. Refer to Note 9 – Restructuring in Item 8 of Part II of this Annual Report on Form 10-K for more information on restructuring costs**.** Excluding these costs, QEP G&A expense decreased by $55.1 million, primarily due to the initiative in reducing general and administrative expenses to ensure our cost structure is competitive with industry peers. The reduction is primarily attributable to $37.3 million lower labor, benefits and other associated costs as of a result of the reduction in our workforce, $8.2 million in lower stock-based compensation costs and $5.6 million in lower outside services costs, partially offset by a $7.9 million decrease in overhead recoveries, primarily associated with our Haynesville/Cotton Valley and Uinta Basin divestitures.

Net gain (loss) from asset sales, inclusive of restructuring costs. During the year ended December 31, 2019, QEP recognized a gain on sale of assets of $3.9 million, compared to a gain on sale of $25.0 million during the year ended December 31, 2018. The gain on sale of assets recognized in 2019 was primarily related to a net pre-tax gain on sale of $7.6 million related to the divestiture of properties outside our main operating areas, partially offset by the $2.7 million pre-tax loss on the sale of the corporate aircraft and a pre-tax loss on sale, including restructuring costs, of $1.0 million related to the Haynesville Divestiture. 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 9 – Restructuring in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Non-Operating Expenses

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, 2019, losses on commodity derivative instruments were $173.4 million, of which $140.1 million were unrealized losses related to our production contracts and $35.1 million were realized losses, partially offset by $1.8 million of unrealized gains related to the Haynesville Divestiture. During 2018, gains on commodity derivative instruments were $90.4 million, of which $254.4 million were unrealized gains and $158.1 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) changed by $14.3 million with more income during the year ended December 31, 2019, compared to 2018. The increase in other income was primarily related to a $5.1 million gain on the deferred compensation plan, a decreased loss on sale of inventory of $4.7 million, a decrease in pension expense of $3.1 million and an increase in interest income of $1.7 million.

Interest expense. Interest expense decreased $21.3 million, or 14%, during the year ended December 31, 2019, compared to 2018. The decrease during the year ended December 31, 2019 was primarily related to decreased borrowings under the credit facility and the reduction of accrued interest on the Company's uncertain tax position.

Income tax (provision) benefit. Income tax benefit decreased $274.4 million during the year ended December 31, 2019 compared to 2018. The decrease in income tax benefit was the result of decreased net loss before income taxes. The combined effective federal and state income tax rate was 30.6% during the year ended December 31, 2019, compared to 23.9% for the year ended December 31, 2018. The 2019 tax rate was driven higher by the re-measurement of QEP's deferred tax assets and liabilities at a lower blended state tax rate due to exiting the state of Louisiana and reversal of our uncertain tax position, partially offset by permanent difference items recognized in 2019 and an increase in the valuation allowance.

LIQUIDITY AND CAPITAL RESOURCES

QEP strives to maintain sufficient liquidity to ensure financial flexibility, withstand commodity price volatility and fund its development projects, operations and capital expenditures and return capital to shareholders. 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 the annual generation of Free Cash Flow, cash on hand and borrowings under its revolving credit facility will be sufficient to fund its operations, capital expenditures, interest expense, debt maturities, including $382.4 million of Senior Notes due March 1, 2021, and quarterly dividends, if declared by the Board, during the next 12 months and the foreseeable future. To the extent that the Company sells additional assets, the Company plans to use the proceeds to fund on-going operations, reduce debt and for general corporate purposes.

During the year ended December 31, 2019, QEP's Board of Directors approved the reinstatement of a quarterly cash dividend of $0.02 per share of common stock and paid $9.6 million in cash dividends in 2019.

During the year ended December 31, 2019, QEP received cash proceeds from the disposition of assets of $678.9 million, of which $633.9 million related to the Haynesville Divestiture and $45.0 million related to the divestiture of other assets outside our main operating areas. The net cash proceeds were used to pay down long-term debt outstanding under QEP's revolving credit facility and for general corporate purposes.

During the year ended December 31, 2018, QEP received aggregate proceeds from the disposition of assets of approximately $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.

As of December 31, 2019, the Company had $166.3 million in cash and cash equivalents, no borrowings outstanding and $2.9 million in letters of credit outstanding under the 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 covenant in its credit facility, which reduced the additional indebtedness that could be incurred. The Company estimates, that as of December 31, 2019, it could incur additional indebtedness of approximately $520.0 million and be in compliance with the covenants contained in its revolving credit facility. The Company estimates that as of December 31, 2019, the maximum allowable total debt it may incur and remain in compliance with the covenants in its credit facility is approximately $2,550 million. 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 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 3.75 times consolidated EBITDA (as defined in the credit agreement), beginning January 1, 2019 and (iii) 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 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, 2019 and 2018, QEP was in compliance with the covenants under the credit agreement.

During the year ended December 31, 2019, QEP's weighted-average interest rate on borrowings from its credit facility was 4.73%. As of December 31, 2019, QEP had no borrowings outstanding and $2.9 million in letters of credit outstanding under the credit facility. 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 February 14, 2020, QEP had no borrowings outstanding and had $2.9 million of letters of credit outstanding under the credit facility. The Company estimates that as of February 14, 2020, the maximum allowable total debt (sum of senior notes and credit facility) that could have been incurred by the Company and remain in compliance with the covenants under its revolving credit facility was approximately $2,475 million.

Senior Notes

The Company's senior notes outstanding as of December 31, 2019, totaled $2,032.4 million principal amount and are comprised of four issuances as follows:

- $382.4 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.

During the year ended December 31, 2019, QEP redeemed all $51.7 million of its outstanding 6.80% Senior Notes due March 2020 and repurchased $15.2 million of its 6.875% Senior Notes due March 2021.

The Company expects to fund the maturity of its 6.875% Senior Notes due March 2021 with cash on hand, the annual generation of Free Cash Flow, the expected AMT credit refunds, proceeds from potential asset sales, and borrowings under its revolving credit facility. The credit facility has various financial covenants that limit the amount of debt the Company can incur, including the present value of the Company’s reserves. An updated present value calculation is required to be delivered to the bank group by April 1 of each year and is calculated using the prior year end reserve report and an average commodity price deck provided by a subset of the bank group. Based on the Company’s December 31, 2019 reserves, and current commodity pricing, the Company believes there will be sufficient availability under its revolving credit facility to continue to fund ongoing operations, including funding of a portion of the 2021 Senior Notes repayment. As discussed in Item 1A. Risk Factors of Part I of this Annual Report, the Company can make no assurance regarding future availability under its revolving credit facility or continued compliance with restrictive financial covenants if its current projections or material underlying assumptions prove to be incorrect. Further, if the Company fails to comply with the covenants, the Company may not be able to borrow under the credit facility.

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), cash related operating expenses 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 24 months.

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

	Year Ended December 31,			Change	
	2019	2018	2017	**2019 vs 2018**	2018 vs 2017
			(in millions)		
Net income (loss)	**$ (97.3)**	(1,011.6)	$ 269.3	**$ 914.3**	$ (1,280.9)
Non-cash adjustments to net income (loss)	**707.0**	1,934.4	340.3	**(1,227.4)**	1,594.1
Changes in operating assets and liabilities	**(42.8)**	(106.6)	(9.4)	**63.8**	(97.2)
Net cash provided by (used in) operating activities	**$ 566.9**	$ 816.2	$ 600.2	**$ (249.3)**	$ 216.0

Net cash provided by operating activities during the year ended December 31, 2019, decreased $249.3 million compared to 2018, which was due to a $1,227.4 million decrease in non-cash adjustments to the net loss, partially offset by a $914.3 million decrease in the net loss and a $63.8 million increase in cash from operating assets and liabilities. During the year ended December 31, 2019, non-cash adjustments to the net loss primarily included DD&A expense of $540.0 million, unrealized losses on derivative contracts of $138.3 million, share-based compensation expense of $20.8 million and deferred income taxes of $4.3 million. The change in operating assets and liabilities of $42.8 million was primarily due to a decrease in long-term tax payables and post retirement benefit obligations of $45.2 million and a decrease in accounts payable and accrued expenses of $40.4 million, partially offset by a decrease in accrued income taxes receivable of $38.4 million.

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 $1,594.1 million increase in non-cash adjustments to the net loss and a $97.2 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 $30.9 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 changes in operating assets and liabilities of $106.6 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.

Cash Flow from Investing Activities

A comparison of capital expenditures for the years ended December 31, 2019, 2018 and 2017, are presented in the table below:

	Year Ended December 31,			Change	
	2019	2018	2017	**2019 vs 2018**	2018 vs 2017
			(in millions)		
Property acquisitions	**$ 3.5**	$ 65.6	$ 815.2	**$ (62.1)**	$ (749.6)
Property, plant and equipment capital expenditures	**571.5**	1,176.6	1,219.8	**(605.1)**	(43.2)
Total accrued capital expenditures	**575.0**	1,242.2	2,035.0	**(667.2)**	(792.8)
Change in accruals and other non-cash adjustments	**(8.8)**	57.4	(60.2)	**(66.2)**	117.6
Total cash capital expenditures	**$ 566.2**	$ 1,299.6	$ 1,974.8	**$ (733.4)**	$ (675.2)

During the year ended December 31, 2019, on an accrual basis, the Company invested $571.5 million on property, plant and equipment capital expenditures (which excludes property acquisitions), a decrease of $605.1 million compared to 2018. In 2019, QEP's primary capital expenditures included $477.1 million in the Permian Basin (including midstream infrastructure of $41.8 million, primarily related to oil and gas gathering and water handling) and $94.2 million in the Williston Basin. The reduction in capital expenditures from 2019 to 2018 is a result of the Company's focus on capital efficiency and its desire to generate Free Cash Flow, causing a 45% reduction in Permian and Williston basin capital expenditures and the Haynesville and Uinta basin divestitures.

During the year ended December 31, 2018, on an accrual basis, the Company invested $1,176.6 million on property, plant and equipment expenditures, excluding property acquisitions, a decrease of $43.2 million compared to 2017, primarily due to increased 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.

The mid-point of our 2020 forecasted capital expenditures is $570.0 million. QEP intends to fund capital expenditures with cash flow from operating activities, cash on hand and, if needed, borrowings under the credit facility. The aggregate levels of capital expenditures for 2020 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, 2019, net cash used in financing activities was $511.3 million compared to net cash provided by financing activities of $244.6 million during the year ended December 31, 2018. During the year ended December 31, 2019, QEP made repayments under its credit facility of $486.0 million, repaid an aggregate of $66.9 million of its senior notes, which were due in 2020 and 2021 and paid $9.6 million in dividends. These cash outflows were offset by borrowings under its credit facility of $56.1 million. In addition, QEP had treasury stock repurchases of $7.6 million related to the settlement of employment tax and related benefit withholding obligations arising from the vesting of restricted share grants. During 2019, QEP had a decrease in checks outstanding in excess of cash balances of $3.7 million. As of December 31, 2019, long-term debt consisted of $2,015.6 million total debt, of which $2,032.4 million is senior notes and $16.8 million is net original issue discount and unamortized debt issuance costs.

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 under its credit facility of $3,608.0 million and repaid $3,267.0 million on its credit facility. 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. As of December 31, 2018, long-term debt consisted of $2,507.1 million total debt, of which $2,099.3 million was senior notes, $430.0 million outstanding on the credit facility, and $22.2 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, 2019, the Company's material off-balance sheet arrangements included 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, 2019:

	Payments Due by Year[1]						
	Total	2020	2021	2022	2023	2024	After 2024
	(in millions)						
Long-term debt	$ 2,032.4	$ —	$ 382.4	$ 500.0	$ 650.0	$ —	$ 500.0
Interest on fixed-rate, long-term debt[2]	391.7	115.4	93.5	82.4	39.5	28.1	32.8
Drilling contracts	1.7	1.7	—	—	—	—	—
Gathering, processing, firm transportation and other	89.0	23.5	23.8	19.4	9.5	5.6	7.2
Asset retirement obligations[3]	100.9	8.7	2.3	2.2	1.8	2.9	83.0
Building, compressor, generator and equipment operating leases	73.0	22.3	20.4	15.9	10.6	1.4	2.4
Total	$ 2,688.7	$ 171.6	$ 522.4	$ 619.9	$ 711.4	$ 38.0	$ 625.4

(1) This table excludes the Company's benefit plan liabilities as future payment dates are unknown. Refer to Note 13 – 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 the year ended December 31, 2019, commodity prices decreased from the previous year. During each of the years ended December 31, 2018 and 2017, 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 consolidated 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 consolidated financial statements and related 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 16 – 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 estimates of future production, future commodity prices, future operating costs and future development costs. 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. Cash flow estimates relating to future cash flows from probable and possible reserves are reduced by additional risk-weighting factors. During the year ended December 31, 2019, the Company recorded no impairment of proved properties. During the years ended December 31, 2018 and 2017, QEP recorded impairment expense of $1,524.6 million and $38.1 million, respectively, related to proved properties. During the year ended December 31, 2018, the impairment recorded was primarily the result of signing purchase and sale agreements related to the Terminated Williston Basin Divestiture and the Uinta Basin Divestiture. During the year ended December 31, 2017, the impairment recorded related to some of QEP's higher cost, proved properties in both of its Northern and Southern regions, due to lower forward prices.

During the year ended December 31, 2019, the Company recorded impairments of $5.0 million related to an office building lease.

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, 2019, the Company recorded no impairment of unproved properties. During the years ended December 31, 2018 and 2017, QEP recorded impairment charges of $36.3 million and $29.0 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.

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, 2019 and 2018 was $100.9 million and $159.6 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, 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 and condensate 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 11 – 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, basis 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.

Share-Based Compensation

QEP issues restricted share awards and restricted share units to certain officers, employees and non-employee directors under its 2018 Long-Term Incentive Plan (LTIP). QEP historically issued stock options. QEP used 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 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 12 – 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 14 – Income Taxes in Item 8 of Part II of this Annual Report on Form 10-K for more information.

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.

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, 2019, QEP held commodity price derivative contracts, excluding basis swaps, totaling 17.5 million barrels of oil. 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.

The following table presents QEP's volumes and average prices for its derivative positions as of February 14, 2020. 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, 2019.

Production Commodity Derivative Swaps

Year	Index	Total Volumes		Average Swap Price per Unit
		(in millions)		
Oil sales		(bbls)		($/bbl)
2020	NYMEX WTI	13.0	$	57.81
2020	Argus WTI Midland	1.3	$	57.30
2020	Argus WTI Houston	0.8	$	60.06
2021	NYMEX WTI	1.6	$	55.04

Production Commodity Derivative Basis Swaps

Year	Index	Basis	Total Volumes		Weighted-Average Differential
			(in millions)		
Oil sales			(bbls)		($/bbl)
2020	NYMEX WTI	Argus WTI Midland	6.2	$	0.19
2020	NYMEX WTI	Argus WTI Houston	0.3	$	3.75
2021	NYMEX WTI	Argus WTI Midland	4.4	$	0.99

Changes in the fair value of derivative contracts from December 31, 2018 to December 31, 2019, are presented below:

		Commodity derivative contracts
		(in millions)
Net fair value of oil and gas derivative contracts outstanding at December 31, 2018	$	122.5
Contracts settled		**35.1**
Change in oil and gas prices on futures markets		**(155.0)**
Contracts added		**(20.1)**
Net fair value of oil and gas derivative contracts outstanding at December 31, 2019	**$**	**(17.5)**

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, 2019	
	(in millions)	
Net fair value – asset (liability)	**$**	**(17.5)**
Fair value if market prices of oil, gas and basis differentials decline by 10%	**$**	**(15.8)**
Fair value if market prices of oil, gas and basis differentials increase by 10%	**$**	**(19.3)**

Utilizing the actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these instruments by $1.8 million, while a 10% decrease in underlying commodity prices would increase the fair value of these instruments by $1.7 million as of December 31, 2019. 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, 2019, QEP had no borrowings outstanding under its revolving credit facility, and as of December 31, 2018, QEP had $430.0 million outstanding under its revolving credit facility. If interest rates were to increase or decrease 10% during the year ended December 31, 2019, at our average level of borrowing for those same periods, the Company's interest expense would increase or decrease by less than $0.1 million, or less than 1% of total interest expense. The Company's total outstanding debt of $2,032.4 million 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 10 – Debt in Item 8 of Part II of this Annual Report on Form 10-K.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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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, 2019 and 2018, 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, 2019, 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, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with 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, 2019, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Note 8 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

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.

Critical Audit Matters

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

The Impact of Proved Oil and Condensate, Gas, and NGL Reserves on Proved Oil and Gas Properties, Net

As described in Notes 1 and 6 to the consolidated financial statements, the Company follows the successful efforts method of accounting for oil and gas property acquisitions, exploration, development, and production activities. Under this method, proved oil and gas properties are evaluated on a field-by-field basis for potential impairment 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. If impairment is indicated, fair value is estimated using the income approach including an internally developed cash flow model discounted at an appropriate weighted average cost of capital. As of December 31, 2019, the carrying value of the proved oil and gas properties, net was $4,324 million and depreciation, depletion, and amortization (DD&A) expense for the year ended December 31, 2019 was $540 million. Cash flow estimates require forecasts and assumptions for many years into the future for a variety of factors, including future production, future commodity prices, future operating costs, and future development costs. Cash flow estimates relating to future cash flows from probable and possible reserves are reduced by additional risk-weighting factors. 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 principal considerations for our determination that performing procedures relating to the impact of proved oil and condensate, gas, and NGL reserves on proved oil and gas properties, net is a critical audit matter are there was significant judgment required by management, including the use of specialists, when developing the expected future cash flows and estimates of oil and condensate, gas, and NGL reserves. This in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures to evaluate the expected future cash flows and estimates of oil and condensate, gas, and NGL reserves, which included significant assumptions relating to estimates of future production volumes, commodity prices, and future operating and development costs.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of oil and condensate, gas, and NGL reserves, evaluation of the potential impairment of proved oil and gas properties, including the determination of the fair value of the proved oil and gas properties, and the calculation of DD&A expense. These procedures also included, among others, evaluating the significant assumptions used by management in developing these estimates including future production volumes, commodity prices and future operating and development costs, and testing the unit-of-production rate used to calculate DD&A expense. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of these estimates of oil and condensate, gas, and NGL reserves. As a basis for using this work, the specialists' qualifications and objectivity were understood, as well as the methods and assumptions used by the specialists. The procedures performed also included tests of the data used by the specialists and an evaluation of the specialists' findings.

/s/ PricewaterhouseCoopers LLP
Denver, Colorado
February 26, 2020

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

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2019	2018	2017
REVENUES	(in millions, except per share amounts)		
Oil and condensate, gas and NGL sales	**$ 1,187.4**	$ 1,871.3	$ 1,545.3
Other revenues	**7.9**	12.5	15.0
Purchased oil and gas sales	**10.9**	48.8	62.6
Total Revenues	**1,206.2**	1,932.6	1,622.9
OPERATING EXPENSES			
Purchased oil and gas expense	**11.0**	51.0	64.3
Lease operating expense	**182.9**	263.1	294.8
Transportation and processing costs	**48.7**	117.6	245.3
Gathering and other expense	**13.2**	15.5	7.3
General and administrative	**155.8**	221.7	153.5
Production and property taxes	**95.9**	130.8	114.3
Depreciation, depletion and amortization	**540.0**	857.1	754.5
Exploration expenses	**0.1**	0.3	22.0
Impairment	**5.0**	1,560.9	78.9
Total Operating Expenses	**1,052.6**	3,218.0	1,734.9
Net gain (loss) from asset sales, inclusive of restructuring costs	**3.9**	25.0	213.5
OPERATING INCOME (LOSS)	**157.5**	(1,260.4)	101.5
Realized and unrealized gains (losses) on derivative contracts (Note 7)	**(173.4)**	90.4	24.5
Interest and other income (expense)	**4.7**	(9.6)	1.6
Loss from early extinguishment of debt	**(1.0)**	—	(32.7)
Interest expense	**(128.1)**	(149.4)	(137.8)
INCOME (LOSS) BEFORE INCOME TAXES	**(140.3)**	(1,329.0)	(42.9)
Income tax (provision) benefit	**43.0**	317.4	312.2
NET INCOME (LOSS)	**$ (97.3)**	$ (1,011.6)	$ 269.3
Earnings (loss) per common share			
Basic	**$ (0.41)**	$ (4.25)	$ 1.12
Diluted	**$ (0.41)**	$ (4.25)	$ 1.12
Weighted-average common shares outstanding			
Used in basic calculation	**237.7**	237.9	240.6
Used in diluted calculation	**237.7**	237.9	240.6

Refer to Notes accompanying the Consolidated Financial Statements.

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

	Year Ended December 31,		
	2019	2018	2017
	(in millions)		
Net income (loss)	**$ (97.3)**	$ (1,011.6)	$ 269.3
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]	**1.1**	(4.2)	5.8
Amortization of prior service cost[4]	**(0.3)**	0.4	0.5
Amortization of net actuarial (gain) loss[5]	**0.4**	0.6	0.3
Net curtailment and settlement cost incurred[6]	**0.6**	0.1	0.4
Other comprehensive income (loss)	**1.8**	(3.2)	5.6
Comprehensive income (loss)	**$ (95.5)**	$ (1,014.8)	$ 274.9

(1) Refer to Recent Accounting Developments 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 expense of $0.3 million for the year ended December 31, 2019, net of income tax benefit of $1.3 million for the year ended December 31, 2018 and net of income tax expense of $1.8 million for the year ended December 31, 2017.
(4) Presented net of income tax benefit of $0.1 million for the year ended December 31, 2019, net of income tax expense of $0.1 million and $0.2 million for the years ended December 31, 2018 and 2017, respectively.
(5) Presented net of income tax expense of $0.1 million, $0.2 million and $0.1 million for the years ended December 31, 2019, 2018 and 2017, respectively.
(6) Presented net of income tax expense $0.2 million for the year ended December 31, 2019 and net of income tax expense of $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, 2019	December 31, 2018
ASSETS	(in millions)	
Current Assets		
Cash and cash equivalents	**$ 166.3**	$ —
Accounts receivable, net	**108.4**	104.3
Income tax receivable	**37.4**	75.9
Fair value of derivative contracts	**1.5**	87.5
Prepaid expenses	**11.4**	12.7
Other current assets	**0.2**	0.2
Total Current Assets	**325.2**	280.6
Property, Plant and Equipment (successful efforts method for oil and gas properties)		
Proved properties	**9,574.9**	9,096.9
Unproved properties	**599.1**	705.5
Gathering and other	**164.2**	167.7
Materials and supplies	**15.6**	29.9
Total Property, Plant and Equipment	**10,353.8**	10,000.0
Less Accumulated Depreciation, Depletion and Amortization		
Exploration and production	**5,250.5**	4,882.4
Gathering and other	**61.0**	58.1
Total Accumulated Depreciation, Depletion and Amortization	**5,311.5**	4,940.5
Net Property, Plant and Equipment	**5,042.3**	5,059.5
Fair value of derivative contracts	**0.2**	35.4
Operating lease right-of-use assets, net	**56.8**	—
Other noncurrent assets	**53.3**	49.6
Noncurrent assets held for sale	**—**	692.7
TOTAL ASSETS	**$ 5,477.8**	$ 6,117.8
LIABILITIES AND EQUITY		
Current Liabilities		
Checks outstanding in excess of cash balances	**$ 18.3**	$ 14.6
Accounts payable and accrued expenses	**227.2**	258.1
Production and property taxes	**18.9**	24.1
Interest payable	**31.0**	32.4
Fair value of derivative contracts	**18.7**	—
Current operating lease liabilities	**18.0**	—
Asset retirement obligations	**6.0**	5.1
Total Current Liabilities	**338.1**	334.3
Long-term debt	**2,015.6**	2,507.1
Deferred income taxes	**274.5**	269.2
Asset retirement obligations	**94.9**	96.9
Fair value of derivative contracts	**0.5**	0.7
Operating lease liabilities	**44.8**	—
Other long-term liabilities	**48.8**	97.4
Other long-term liabilities held for sale	—	61.3
Commitments and Contingencies (Note 11)		
EQUITY		
Common stock - par value $0.01 per share; 500.0 million shares authorized; 242.1 million and 239.8 million shares issued, respectively	**2.4**	2.4
Treasury stock - 4.4 million and 3.1 million shares, respectively	**(55.4)**	(45.6)
Additional paid-in capital	**1,456.5**	1,431.9
Retained earnings	**1,269.6**	1,376.5
Accumulated other comprehensive income (loss)	**(12.5)**	(14.3)
Total Common Shareholders' Equity	**2,660.6**	2,750.9
TOTAL LIABILITIES AND EQUITY	**$ 5,477.8**	$ 6,117.8

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, 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
Net income (loss)	**—**	**—**	**—**	**—**	**—**	**(97.3)**	**—**	**(97.3)**
Cash dividends declared, $0.02 per share	**—**	**—**	**—**	**—**	**—**	**(9.6)**	**—**	**(9.6)**
Share-based compensation	**2.3**	**—**	**(1.3)**	**(9.8)**	**24.6**	**—**	**—**	**14.8**
Change in pension and postretirement liability, net of tax	**—**	**—**	**—**	**—**	**—**	**—**	**1.8**	**1.8**
Balance at December 31, 2019	**242.1**	**$ 2.4**	**(4.4)**	**$ (55.4)**	**$ 1,456.5**	**$ 1,269.6**	**$ (12.5)**	**$ 2,660.6**

Refer to Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2019	2018	2017
OPERATING ACTIVITIES	(in millions)		
Net income (loss)	**$ (97.3)**	$ (1,011.6)	$ 269.3
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	**540.0**	857.1	754.5
Deferred income taxes	**4.3**	(247.6)	(314.8)
Impairment	**5.0**	1,560.9	78.9
Dry hole exploratory well expense	**—**	—	21.3
Non-cash share-based compensation	**20.8**	30.9	26.9
Amortization of debt issuance costs and discounts	**5.4**	5.4	6.2
Bargain purchase gain from acquisitions	**—**	—	0.4
Net (gain) loss from asset sales, inclusive of restructuring costs	**(3.9)**	(25.0)	(213.5)
Loss from early extinguishment of debt	**1.0**	—	32.7
Unrealized (gains) losses on marketable securities	**(3.9)**	1.2	(2.9)
Unrealized (gains) losses on derivative contracts	**138.3**	(248.5)	(40.0)
Other non-cash activity	**—**	—	(9.4)
Changes in operating assets and liabilities			
Accounts receivable	**(4.1)**	33.7	(2.0)
Prepaid expenses	**(0.4)**	(2.0)	(1.3)
Accounts payable and accrued expenses	**(40.4)**	(74.2)	3.5
Income taxes receivable	**38.4**	(71.0)	13.7
Other	**(36.3)**	6.9	(23.3)
Net Cash Provided by (Used in) Operating Activities	**566.9**	816.2	600.2
INVESTING ACTIVITIES			
Property acquisitions	**(3.5)**	(65.6)	(815.2)
Property, plant and equipment	**(562.7)**	(1,234.1)	(1,159.6)
Proceeds from disposition of assets	**678.9**	243.6	806.8
Net Cash Provided by (Used in) Investing Activities	**112.7**	(1,056.1)	(1,168.0)
FINANCING ACTIVITIES			
Checks outstanding in excess of cash balances	**3.7**	(29.5)	31.7
Long-term debt issued	**—**	—	500.0
Long-term debt issuance costs paid	**—**	(0.1)	(14.4)
Long-term debt extinguishment costs paid	**(1.0)**	—	(28.1)
Long-term debt repaid	**(66.9)**	—	(445.6)
Proceeds from credit facility	**56.1**	3,608.0	492.0
Repayments of credit facility	**(486.0)**	(3,267.0)	(403.0)
Common stock repurchased and retired	**—**	(58.4)	—
Treasury stock repurchases	**(7.6)**	(8.7)	(6.8)
Dividends paid	**(9.6)**	—	—
Other capital contributions	**—**	0.3	—
Net Cash Provided by (Used in) Financing Activities	**(511.3)**	244.6	125.8
Change in cash, cash equivalents and restricted cash[(1)]	**168.3**	4.7	(442.0)
Beginning cash, cash equivalents and restricted cash[(1)]	**28.1**	23.4	465.4
Ending cash, cash equivalents and restricted cash[(1)]	**$ 196.4**	$ 28.1	$ 23.4

(1) Refer to Recent Accounting Developments 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). In January 2019, the Company sold its Haynesville/Cotton Valley assets in Louisiana and in February 2019, the Company announced the termination of the purchase and sale agreement related to its Williston Basin assets in North Dakota. In 2019, QEP's Board of Directors commenced and completed a comprehensive review of strategic alternatives to maximize shareholder value and determined that the best alternative for QEP's shareholders was to move forward as an independent company. 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 Statements of Cash Flows have been reclassified 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 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 production. Refer to Note 7 – Derivative Contracts for the Company's open oil commodity derivative contracts.

Revenue Recognition

QEP recognizes revenue from the sale 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 QEP has no further obligations to perform related to the sale, when the transaction price has been determined and when collectability is probable. The sale 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 indices 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 and condensate is typically sold at specific delivery points under contract terms that are common in the industry. QEP's gas and NGL are also sold under contract types that are common in the 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 QEP 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 credit risk related to third party purchasers, to fulfill volume commitments when production does not fulfill contractual commitments and to capture additional margin from subsequent sales of third party purchases. 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,	
	2019	2018
	(in millions)	
Cash and cash equivalents	**$ 166.3**	$ —
Restricted cash[1]	**30.1**	28.1
Total cash, cash equivalents and restricted cash shown in the Consolidated Statements of Cash Flows	**$ 196.4**	$ 28.1

[1] As of December 31, 2019 and 2018, 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,		
	2019	2018	2017
Supplemental Disclosures:		(in millions)	
Cash paid for interest, net of capitalized interest	**$ 126.9**	$ 136.9	$ 134.9
Cash paid (refund received) for income taxes, net	**$ (66.7)**	$ 0.8	$ (0.3)
Cash paid for amounts included in the measurement of lease liabilities	**$ 25.3**	$ —	$ —
Non-cash Operating Activities:			
Right-of-use assets obtained in exchange for operating lease obligations	**16.6**	—	—
Non-cash Investing Activities:			
Change in capital expenditure accrual balance	**$ 8.8**	$ (57.4)	$ 60.2

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 year ended December 31, 2019 and 2018 was $0.3 million and $0.6 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 $1.6 million at December 31, 2019, and $1.3 million at December 31, 2018.

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 estimates of future production, future commodity prices, future operating costs and future development costs. 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 in which the likelihood of possible outcomes is taken into consideration. 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, 2019, QEP recorded impairment charges of $5.0 million related to an office building lease.

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.

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. The ARO liability is 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 year ended December 31, 2017 QEP recorded $5.3 million of goodwill. In addition, during the year ended December 31, 2017, QEP tested goodwill for impairment, which resulted in a full write-down of the $5.3 million.

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 11 – 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, basis 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 66%, 49%, and 59% of QEP's revenues for the years ended December 31, 2019, 2018 and 2017, respectively. The following table presents the percentages by customer that accounted for 10% or more of QEP's total revenues.

Year Ended December 31, 2019	
Occidental Energy Marketing	**21%**
Valero Marketing & Supply Company	**18%**
Plains Marketing LP	**17%**

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%

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, or recognizes a valuation allowance against deferred tax assets in cases where we do not forecast sufficient future income to recognize the deferred tax asset. All federal income tax returns prior to 2019 have been examined by the Internal Revenue Service and are closed or have been pre-reviewed before filing. Income tax returns for 2019 have not yet been filed. Most state tax returns for 2016 and subsequent years remain subject to examination. Should the Company utilize any of its state loss carryforwards, their carryforward losses would be 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.

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.

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 12 – 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, 2019, 2018 and 2017, there were no anti-dilutive shares.

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

	December 31,		
	2019	2018	2017
		(in millions)	
Weighted-average basic common shares outstanding	**237.7**	237.9	240.6
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	**237.7**	237.9	240.6

Share-Based Compensation

QEP issues restricted share awards and restricted share units to certain officers, employees and non-employee directors under its 2018 Long-Term Incentive Plan (LTIP). QEP historically issued stock options. QEP used 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 12 – 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 13 – 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 February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (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. The Company adopted ASU 2016-02 on January 1, 2019 using the modified retrospective approach and elected to not adjust periods prior to January 1, 2019. The Company elected the package of practical expedients permitted under the transition guidance within the new standard, which, among other things, allowed the carry forward of the historical lease classification, including accounting treatment for land easements. This standard does not apply to QEP's leases that provide the right to explore for minerals, oil or natural gas resources. The adoption of this guidance resulted in the recognition of net operating lease right-of-use assets and operating lease liabilities on QEP's Consolidated Balance Sheets. These leases primarily relate to office buildings, compressors and generators. This guidance did not have a significant impact on the Consolidated Statements of Operations or the Consolidated Statements of Cash Flows. Refer to Note 8 – Leases for more information.

In December 2019, the FASB issued ASU No. 2019-12, *Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes*, which simplifies the accounting for income taxes. 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

Revenue Recognition

QEP recognizes revenue from the sale 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 QEP has no further obligations to perform related to the sale, when the transaction price has been determined and when collectability is probable. The sale 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 indices 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 and condensate is typically sold at specific delivery points under contract terms that are common in the industry. QEP's gas and NGL are also sold under contract types that are common in the 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 QEP 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 credit risk related to third party purchasers, to fulfill volume commitments when production does not fulfill contractual commitments and to capture additional margin from subsequent sales of third party purchases. QEP recognizes revenue from these resale activities in the period that the performance obligations are satisfied.

The following tables present QEP's 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, 2019				
Northern Region					
Williston Basin	**$ 420.8**	**$ 33.1**	**$ 19.4**	**$ (34.4)**	**$ 438.9**
Other Northern	**1.1**	**0.4**	**0.1**	**—**	**1.6**
Southern Region					
Permian Basin	**710.6**	**12.8**	**37.8**	**(20.5)**	**740.7**
Other Southern[1]	**0.1**	**6.1**	**—**	**—**	**6.2**
Total oil and condensate, gas and NGL sales	**$ 1,132.6**	**$ 52.4**	**$ 57.3**	**$ (54.9)**	**$ 1,187.4**
	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	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

(1) For the year ended December 31, 2019, $5.9 million of revenues associated with Haynesville/Cotton Valley have been included in Other Southern.
(2) Prior period amounts have not been adjusted under the modified retrospective method under ASC Topic 606.

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 consisted of approximately 15,100 acres, mainly in Martin County, Texas, which were held by production from existing vertical wells at the time of the acquisition. 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.

Other Acquisitions

During the years ended December 31, 2019 and 2018, QEP acquired various oil and gas properties, which primarily included proved leasehold acreage in the Permian Basin for an aggregate purchase price of $3.5 million and $16.5 million, respectively, 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. In conjunction with the acquisitions, the Company recorded $5.3 million of goodwill, which was subsequently impaired.

Divestitures

In February 2018, QEP's Board of Directors (Board) unanimously approved certain strategic and financial 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. The Company subsequently sold its Uinta Basin assets in September 2018 and sold its Haynesville/Cotton Valley assets in January 2019. In addition, the Company entered into a purchase and sale agreement for its Williston Basin assets in November 2018. However, in February 2019, the Company agreed with the buyer to terminate the purchase and sale agreement (Terminated Williston Basin Divestiture).

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 their 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 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. In January 2019, QEP closed the Haynesville Divestiture and during the year ended December 31, 2019 reached final settlement on asserted title defects and received net cash proceeds of $633.9 million. During the years ended December 31, 2019 and 2018, QEP recorded a pre-tax loss, including restructuring costs, of $1.0 million and $3.0 million, respectively, which were recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations.

During the year ended December 31, 2019, QEP accounted for revenues and expenses related to Haynesville/Cotton Valley, including the pre-tax loss on sale of $1.0 million as income from continuing operations on the Consolidated Statements of Operations because the Haynesville Divestiture did not cause a strategic shift for the Company and therefore did not qualify as discontinued operations under ASU 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*. During the year ended December 31, 2019, QEP recorded net income before income taxes related to the divested Haynesville/Cotton Valley assets, prior to divestiture, of $3.2 million which includes the pre-tax loss on sale of $1.0 million. During the year ended December 31, 2018, QEP recorded net income before income taxes related to the divested Haynesville/Cotton Valley assets of $76.0 million.

Since the transaction was substantially finalized as of December 31, 2018, the assets and liabilities associated with the Haynesville Divestiture were 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 $1.4 million and $3.0 million of restructuring costs related to this divestiture during the years ended December 31, 2019 and 2018, respectively, included in "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations. Refer to Note 9 – Restructuring 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 [1]
	(in millions)
Assets	
Current assets, total	**$ 1.2**
Property, Plant and Equipment	**683.7**
Other noncurrent assets	**7.8**
Noncurrent assets held for sale	**$ 692.7**
Liabilities	
Current liabilities, total	**$ 3.4**
Asset retirement obligations, current	**0.7**
Asset retirement obligations, long-term	**56.9**
Fair value of derivative contracts, long-term	**—**
Other long-term liabilities	**0.3**
Other long-term liabilities held for sale	**$ 61.3**

[1] The Haynesville Divestiture closed in January 2019, therefore there are no assets and liabilities held for sale as of December 31, 2019.

Terminated 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. 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 buyer's shareholders and regulatory approvals. In February 2019, the Company agreed with the buyer to terminate the purchase and sale agreement. 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 our strategic initiatives, QEP has incurred costs associated with contractual termination benefits, including severance, accelerated vesting of share-based compensation and other expenses. Refer to Note 9 – Restructuring and Note 17 – Subsequent Events for more information.

Uinta Basin Divestiture

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, (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. For the year ended December 31, 2019, QEP recorded a pre-tax loss of $0.2 million, due to post-closing purchase price adjustments, which were recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs". Refer to Note 1 – Summary of Significant Accounting Policies and Note 9 – Restructuring 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.

As part of the purchase and sale agreement, QEP agreed to reimburse the buyer for certain deficiency charges that totaled $9.3 million as of December 31, 2018 and is reported on the Consolidated Balance Sheets within "Accounts payable and accrued expenses". As of December 31, 2019, QEP has no remaining liability related to this commitment.

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.

Other Divestitures

In addition to the Haynesville and Uinta Basin divestitures, during the year ended December 31, 2019, QEP received net cash proceeds of $45.1 million and recorded a net pre-tax gain on sale of $5.1 million related to the divestiture of properties outside our main operating areas.

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.

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		
	2019	2018	2017
	(in millions)		
Balance at January 1,	**$ —**	$ —	$ 14.2
Additions to capitalized exploratory well costs	**—**	—	10.7
Reclassifications to proved properties	**—**	—	(3.6)
Capitalized exploratory well costs charged to expense	**—**	—	(21.3)
Balance at December 31,	**$ —**	$ —	$ —

During the year ended December 31, 2017, 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,	
	2019	2018
Balance Sheet line item	(in millions)	
Current:		
Asset retirement obligations, current liability	**$ 6.0**	$ 5.1
Long-term:		
Asset retirement obligations	**94.9**	96.9
Other long-term liabilities held for sale	**—**	57.6
Total ARO Liability	**$ 100.9**	$ 159.6

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

	Asset Retirement Obligations	
	2019	2018
	(in millions)	
ARO liability at January 1,	**$ 159.6**	$ 214.1
Accretion	**5.2**	6.4
Additions	**1.1**	4.1
Revisions	**(2.2)**	(4.9)
Liabilities related to assets sold[1]	**(60.7)**	(56.8)
Liabilities settled	**(2.1)**	(3.3)
ARO liability at December 31,	**$ 100.9**	$ 159.6

[1] Liabilities related to assets sold for the year ended December 31, 2019, includes $57.6 million related to the Haynesville Divestiture. Liabilities related to assets sold for the year ended December 31, 2018, includes $51.0 million related to the Uinta Basin 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, 2019 and 2018, is shown in the table below:

	Fair Value Measurements				
	Gross Amounts of Assets and Liabilities				Net Amounts Presented on the Consolidated Balance Sheets
	Level 1	Level 2	Level 3	Netting Adjustments[1]	
	(in millions)				
	December 31, 2019				
Financial Assets					
Fair value of derivative contracts – short-term	**$ —**	**$ 1.5**	**$ —**	**$ —**	**$ 1.5**
Fair value of derivative contracts – long-term	**—**	**0.2**	**—**	**—**	**0.2**
Total financial assets	**$ —**	**$ 1.7**	**$ —**	**$ —**	**$ 1.7**
Financial Liabilities					
Fair value of derivative contracts – short-term	**$ —**	**$ 18.7**	**$ —**	**$ —**	**$ 18.7**
Fair value of derivative contracts – long-term	**—**	**0.5**	**—**	**—**	**0.5**
Total financial liabilities	**$ —**	**$ 19.2**	**$ —**	**$ —**	**$ 19.2**
	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

(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 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, 2019		December 31, 2018	
Financial Assets	(in millions)			
Cash and cash equivalents	**$ 166.3**	**$ 166.3**	$ —	$ —
Financial Liabilities				
Checks outstanding in excess of cash balances	**$ 18.3**	**$ 18.3**	$ 14.6	$ 14.6
Long-term debt	**$ 2,015.6**	**$ 2,029.4**	$ 2,507.1	$ 2,350.5

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 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 and operating lease right-of-use assets 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 year ended December 31, 2019, the Company recorded impairments of $5.0 million related to an office building lease. During the years ended December 31, 2018 and 2017, the Company recorded impairments on certain proved oil and gas properties of $1,524.6 million and $38.1 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.

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. QEP typically enters into commodity derivative transactions covering a substantial, but varying, portion of its anticipated oil and gas production for the next 12 to 24 months. 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 HH 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, 2019:

Year	Index	Total Volumes		Average Swap Price per Unit
		(in millions)		
Oil sales		(bbls)		($/bbl)
2020	NYMEX WTI	14.1	$	57.83
2020	Argus WTI Houston	1.0	$	60.06
2020	Argus WTI Midland	1.5	$	57.30
2021	NYMEX WTI	0.9	$	55.06

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, 2019:

Year	Index	Basis	Total Volumes		Weighted-Average Differential
			(in millions)		
Oil sales			(bbls)		($/bbl)
2020	NYMEX WTI	Argus WTI Midland	6.8	$	0.18
2020	NYMEX WTI	Argus WTI Houston	0.4	$	3.75
2021	NYMEX WTI	Argus WTI Midland	3.7	$	0.98

QEP Derivative Financial Statement Presentation

The following table identifies the Consolidated Balance Sheets 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	**2019**	2018	**2019**	2018
Current:		(in millions)			
Commodity	Fair value of derivative contracts	**$ 1.5**	$ 88.2	**$ 18.7**	$ 0.4
Long-term:					
Commodity	Fair value of derivative contracts	**0.2**	35.4	**0.5**	0.7
Total derivative instruments[1]		**$ 1.7**	$ 123.6	**$ 19.2**	$ 1.1

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

Derivative contracts	Year Ended December 31, 2019	2018	2017
Realized gains (losses) on commodity derivative contracts		(in millions)	
Production			
Oil derivative contracts	**$ (32.2)**	$ (153.4)	$ 6.8
Gas derivative contracts	**(2.9)**	(5.0)	(22.3)
Gas Storage			
Gas derivative contracts	**—**	0.3	—
Realized gains (losses) on commodity derivative contracts	**(35.1)**	(158.1)	(15.5)
Unrealized gains (losses) on commodity derivative contracts			
Production			
Oil derivative contracts	**(139.8)**	277.0	(66.2)
Gas derivative contracts	**(0.3)**	(22.3)	133.6
Gas Storage			
Gas derivative contracts	**—**	(0.3)	2.5
Unrealized gains (losses) on commodity derivative contracts	**(140.1)**	254.4	69.9
Total realized and unrealized gains (losses) on commodity derivative contracts related to production and storage contracts	**$ (175.2)**	$ 96.3	$ 54.4
Derivatives associated with divestitures			
Unrealized gains (losses) on commodity derivative contracts			
Production			
Oil derivative contracts	**$ —**	$ (2.7)	$ (1.3)
Gas derivative contracts	**1.8**	—	(23.5)
NGL derivative contracts	**—**	(3.2)	(5.1)
Unrealized gains (losses) on commodity derivative contracts related to divestitures[(1)(2)(3)]	**$ 1.8**	$ (5.9)	$ (29.9)
Total realized and unrealized gains (losses) on commodity derivative contracts	**$ (173.4)**	$ 90.4	$ 24.5

(1) During the year ended December 31, 2019 , the unrealized gains (losses) on commodity derivative contracts related to the Haynesville Divestiture are comprised of derivatives included as part of the Haynesville/Cotton Valley purchase and sale agreement, which were subsequently novated to the buyer upon the closing of the sale in January 2019. Refer to Note 3 – Acquisitions and Divestitures for more information. The unrealized gains (losses) on commodity derivatives associated with the Haynesville 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, 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.

(3) 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 – Leases

Adoption of ASC Topic 842, *Leases*

On January 1, 2019, QEP adopted ASC Topic 842, *Leases*, using the modified retrospective approach, which was applied to historical leases that were still effective as of January 1, 2019. Results for reporting periods beginning January 1, 2019, are presented in accordance with ASC Topic 842, while prior period amounts are reported in accordance with historical accounting treatment under ASC Topic 840, *Leases*.

In accordance with the adoption of ASC Topic 842, QEP now records a net operating lease right-of-use (ROU) asset and operating lease liability on the Consolidated Balance Sheets for all operating leases with a contract term in excess of 12 months. Prior to the adoption of ASC Topic 842, these same leases were treated as operating leases under ASC Topic 840 and therefore were not recorded on the December 31, 2018 Consolidated Balance Sheet. There was no impact to retained earnings and no significant impact on the Consolidated Statements of Operations or the Consolidated Statements of Cash Flows as a result of adopting ASC Topic 842.

Lease Recognition

QEP enters into contractual lease arrangements to rent office space, compressors, generators, drilling rigs and other equipment from third-party lessors. ROU assets represent QEP’s right to use an underlying asset for the lease term and lease liabilities represent QEP’s obligation to make future lease payments arising from the lease. Operating lease ROU assets and liabilities are recorded at commencement date based on the present value of lease payments over the lease term. Leases with an initial term of 12 months or less are not recorded on the Consolidated Balance Sheets. The Company recognizes lease expense for these short-term leases on a straight-line basis over the lease term. With the exception of generators, QEP does not account for lease components separately from the non-lease components. The contractual consideration provided under QEP's leased generators is allocated between lease components, such as equipment, and non-lease components, such as maintenance service fees, based on estimated costs from the vendor. QEP uses the implicit interest rate when readily determinable. However, most of QEP's lease agreements do not provide an implicit interest rate. As such, QEP uses its incremental borrowing rate based on the information available at commencement date of the contract in determining the present value of future lease payments. The incremental borrowing rate is calculated using a risk-free interest rate adjusted for QEP's risk. The operating lease ROU asset also includes any lease incentives received in the recognition of the present value of future lease payments. Certain of QEP's leases may also include escalation clauses or options to extend or terminate the lease. These options are included in the present value recorded for the leases when it is reasonably certain that QEP will exercise that option. Lease expense for lease payments is recognized on a straight-line basis over the lease term.

QEP determines if an arrangement is a lease at inception of the contract and records the resulting operating lease asset on the Consolidated Balance Sheets as “Operating lease right-of-use assets, net” with offsetting liabilities recorded as “Current operating lease liabilities” and “Operating lease liabilities.” QEP recognizes a lease in the financial statements when the arrangement either explicitly or implicitly involves property, plant, or equipment (PP&E), the contract terms are dependent on the use of the PP&E, and QEP has the ability or right to operate the PP&E or to direct others to operate the PP&E and receive the majority of the economic benefits of the assets. As of December 31, 2019, QEP does not have any financing leases.

Lease costs represent the straight-line lease expense of ROU assets and short-term leases. The components of lease cost are classified as follows:

	As of December 31, 2019 [1]
	(in millions)
Lease Cost included in the Consolidated Balance Sheets	
Property, Plant and Equipment acquisitions [2]	**$ 13.8**

	Year Ended December 31, 2019 [1]
	(in millions)
Lease Cost included in the Consolidated Statement of Operations	
Lease operating expense	**$ 11.9**
Gathering and other expense	**7.7**
General and administrative	**5.7**
Total lease cost	**$ 25.3**

(1) Prior periods are not presented as prior period amounts have not been adjusted under the modified retrospective method for the new lease recognition rule, ASC Topic 842. Refer to Note 1 – Basis of Presentation for additional information.

(2) Represents short-term lease capital expenditures related to drilling rigs for the twelve months ended December 31, 2019. These costs are capitalized as a part of "Proved properties" on the Consolidated Balance Sheets.

Lease term and discount rate related to the Company's leases are as follows:

	December 31, 2019 [1]
Weighted-average remaining lease term (years)	5.4
Weighted-average discount rate	8.0%

(1) Prior periods are not presented as prior period amounts have not been adjusted under the modified retrospective method for the new lease recognition rule, ASC Topic 842. Refer to Note 1 – Basis of Presentation for additional information.

Note 9 – Restructuring

In February 2018, QEP's Board approved certain strategic and financial initiatives. In February 2019, QEP's Board commenced a comprehensive review of strategic alternatives to maximize shareholder value. In connection with these activities, QEP has incurred or expects to incur various restructuring costs associated with contractual termination benefits including severance, accelerated vesting of share-based compensation and other expenses. The termination benefits have been accounted for under ASC 712, *Compensation – Nonretirement Postemployment Benefits* and ASC 718, *Compensation – Stock Compensation*.

Restructuring costs recognized are summarized below:

	Year Ended December 31, 2019			
	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	**$ 12.3**	**$ 12.2**	**$ 0.1**	**—**
Office lease termination costs	**0.6**	**0.6**	**—**	**—**
Accelerated share-based compensation[1]	**12.6**	**11.1**	**1.5**	**—**
Retention expense (including share-based compensation)	**19.5**	**19.5**	**—**	**—**
Pension and Medical Plan curtailment	**1.2**	**—**	**(0.2)**	**1.4**
Total restructuring costs	**$ 46.2**	**$ 43.4**	**$ 1.4**	**$ 1.4**

	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 Statements of Operations for the year ended December 31, 2019 and 2018. Total accelerated share-based compensation was $29.1 million and was determined based on the contractual vesting date, with $12.6 million and $11.0 million recognized in 2019 and 2018, respectively, as shown above, and the remaining amount recognized in prior periods.

	Costs recognized from inception through December 31, 2019 [1]	Total remaining costs expected to be incurred[2]
	(in millions)	
Termination benefits	**$ 44.6**	**$ —** [2]
Office lease termination costs	**1.6**	**—** [2]
Accelerated share-based compensation	**23.6**	**—** [2]
Retention expense (including share-based compensation)	**38.3**	**0.5**
Pension and Medical Plan curtailment	**1.3**	**—** [2]
Total restructuring costs	**$ 109.4**	**$ 0.5**

(1) Represents costs incurred since February 2018 when QEP's Board approved certain strategic and financial initiatives.
(2) Due to the nature of the strategic initiatives, as of December 31, 2019, the Company is not able to reasonably estimate the total cost to be incurred in connection with these restructurings.

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, 2018	$ 19.5	$ —	$ —	$ 10.8	$ —	$ 30.3
Costs incurred and charged to expense	**12.3**	**0.6**	**12.6**	**19.5**	**1.2**	**46.2**
Costs paid or otherwise settled	**(30.6)**	**(0.6)**	**(12.6)**	**(23.8)**	**(1.2)**	**(68.8)**
Balance at December 31, 2019	**$ 1.2**	**$ —**	**$ —**	**$ 6.5**	**$ —**	**$ 7.7**

Note 10 – Debt

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

	December 31,	
	2019	2018
	(in millions)	
Revolving Credit Facility due 2022	**$ —**	$ 430.0
6.80% Senior Notes due 2020	**—**	51.7
6.875% Senior Notes due 2021	**382.4**	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	**(16.8)**	(22.2)
Total long-term debt outstanding	**$ 2,015.6**	$ 2,507.1

Of the total debt outstanding on December 31, 2019, 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 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 3.75 times consolidated EBITDA (as defined in the credit agreement), beginning January 1, 2019, and (iii) 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 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, 2019 and 2018, QEP was in compliance with the covenants under the credit agreement.

During the years ended December 31, 2019 and 2018, QEP's weighted-average interest rates on borrowings from its credit facility were 4.73% and 4.43%, respectively. As of December 31, 2019, QEP had no borrowings outstanding and $2.9 million in letters of credit outstanding under the credit facility. 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.

Senior Notes
At December 31, 2019, the Company had $2,032.4 million principal amount of senior notes outstanding with maturities ranging from March 1, 2021 to March 1, 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. During the year ended December 31, 2019, QEP redeemed all $51.7 million of its outstanding 6.80% Senior Notes due March 2020 and repurchased $15.2 million of its 6.875% Senior Notes due March 2021. During the year ended December 31, 2019, the Company recorded $1.0 million in "Loss from early extinguishment of debt" in the Consolidated Statements of Operations for costs associated with the redemption and repurchase of Senior Notes.

The Company expects to fund the maturity of its 6.875% Senior Notes due March 1, 2021 with cash on hand, cash flow from its operating activities, the expected alternative minimum tax (AMT) credit refunds, proceeds from potential asset sales and borrowings under its revolving credit facility. The credit facility has various financial covenants that limit the amount of debt the Company can incur, including the present value of the Company’s reserves**.** An updated present value calculation is required to be delivered to the bank group by April 1 of each year and is calculated using the prior year end reserve report and an average commodity price deck provided by a subset of the bank group. Based on the Company’s December 31, 2019 reserves, and current commodity pricing, the Company believes there will be sufficient availability under its revolving credit facility to continue to fund ongoing operations, including funding of a portion of the 6.875% Senior Notes repayment. The Company can make no assurance regarding future availability under its revolving credit facility or continued compliance with restrictive financial covenants if its current projections or material underlying assumptions prove to be incorrect. Further, if the Company fails to comply with the covenants, the Company may not be able to borrow under the credit facility.

Note 11 – 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.

Mabee Ranch Royalty Partnership 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.

Overriding Royalty Interest Litigation – In July 2019, owners of small overriding royalty interests in certain wells in the South Antelope oil and gas field in North Dakota filed suit against QEP, alleging QEP has improperly taken deductions for post-production expenses.

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)
2020	$	25.2
2021	$	23.8
2022	$	19.4
2023	$	9.5
2024	$	5.6
After 2024	$	7.2

QEP has entered into contractual lease arrangements to rent office space, compressors, generators, and other equipment from third-party lessors. On January 1, 2019, QEP adopted ASC Topic 842, *Leases*, using the modified retrospective approach. Refer to Note 8 – Leases for additional information. Expense from operating leases were $25.3 million, $30.3 million and $24.9 million during the years ended December 31, 2019, 2018 and 2017, respectively. Amounts for 2018 and 2017 are reported in accordance with historical accounting treatment under ASC Topic 840, *Leases.*

As of December 31, 2019, the maturity analysis for long-term operating leases under the scope of ASC 842 are as follows:

Year		Amount (in millions)
2020	$	22.3
2021	$	20.4
2022	$	15.9
2023	$	10.6
2024	$	1.4
After 2024	$	2.4
Less: Interest[1]	$	(10.2)
Present Value of Lease Liabilities[2]	$	62.8

(1) Calculated using the estimated or stated interest rate for each lease.
(2) Of the total present value of lease liabilities, $18.0 million was recorded in "Current operating lease liabilities" and $44.8 million was recorded in "Operating lease liabilities" on the Consolidated Balance Sheets.

As of December 31, 2018, minimum future contractual payments for long-term operating leases under the scope of ASC 840 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 12 – Share-Based Compensation

In 2018, QEP's Board 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 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. QEP historically issued stock options. 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 8.3 million shares available for future grants under the LTIP at December 31, 2019.

Share-based compensation expense is generally 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, 2019 and 2018, the Company recorded an additional $12.6 million and $11.0 million, respectively, of share-based compensation expense related to the acceleration of vesting that occurred as part of the restructuring program. Of this, $1.5 million and $2.2 million for the year ended December 31, 2019 and 2018, respectively, was recorded in "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations and the remaining $11.1 million and $8.8 million, respectively, is included in share-based compensation expense below. Refer to Note 9 – Restructuring for additional information.

	Year Ended December 31,		
	2019	2018	2017
	(in millions)		
Stock options	**$ 0.4**	$ 1.2	$ 2.3
Restricted share awards	**20.4**	27.5	24.6
Performance share units	**4.3**	8.1	(4.5)
Restricted share units	**0.3**	0.1	—
Total share-based compensation expense	**$ 25.4**	$ 36.9	$ 22.4

Stock Options

QEP used 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 utilized the "simplified" method to estimate the expected term of the stock options granted as there was limited historical exercise data available in estimating the expected term of the stock options. QEP used a historical volatility method to estimate the fair value of stock options awards and the risk-free interest rate was 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 three years 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. During the years ended December 31, 2019 and 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
Weighted-average grant date fair value of awards granted during the period	$ 6.44
Risk-free interest rate range	1.66% - 1.81%
Weighted-average risk-free interest rate	1.8%
Expected price volatility range	43.82% - 46.70%
Weighted-average expected price volatility	43.9%
Expected dividend yield	—%
Expected term in years at the date of grant	4.5

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

	Options Outstanding	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
		(per share)	(in years)	(in millions)
Outstanding at December 31, 2018	2,098,933	$ 22.27		
Exercised	**—**	**—**		
Cancelled	**(296,546)**	**30.81**		
Outstanding at December 31, 2019	**1,802,387**	**$ 20.87**	**2.31**	**$ —**
Options Exercisable at December 31, 2019	**1,780,124**	**$ 20.93**	**2.30**	**$ —**
Unvested Options at December 31, 2019	**22,263**	**$ 15.68**	**4.20**	**$ —**

During the years ended December 31, 2019 and December 31, 2017, there were no exercises of stock options. 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. There was $2.3 million income tax impact for the year ended December 31, 2019, and no income tax impact for the years ended December 31, 2018 and 2017. As of December 31, 2019, there was no unrecognized compensation cost related to stock options granted under the LTSIP. Refer to Note 9 – Restructuring for more information.

Restricted Share Awards

Restricted share award grants typically vest in equal installments over three years 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, 2019, 2018 and 2017, was $32.5 million, $21.5 million and $18.4 million, respectively. There was $5.4 million income tax impact for the year ended December 31, 2019, and no tax impact for the years ended December 31, 2018 and 2017. The weighted-average grant date fair value of restricted share awards granted was $7.72 per share, $9.56 per share and $13.90 per share for the years ended December 31, 2019, 2018 and 2017, respectively. As of December 31, 2019, $9.2 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 1.95 years. The weighted-average vesting period may be reduced due to accelerated vesting of awards under the restructuring program. Refer to Note 9 – Restructuring 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, 2018	3,822,133	$ 10.76
Granted	**2,365,262**	**7.72**
Vested	**(3,093,883)**	**10.49**
Forfeited	**(248,479)**	**9.14**
Unvested balance at December 31, 2019	**2,845,033**	**$ 8.67**

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 three years. The awards are denominated in share units and have historically been paid in cash. 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, 2019, 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 $13.0 million, $2.8 million and $5.3 million for vested performance share units during the years ended December 31, 2019, 2018 and 2017, respectively. The weighted-average grant date fair value of the performance share units granted during the years ended December 31, 2019, 2018 and 2017, was $7.93, $9.55, and $16.90 per share, respectively. As of December 31, 2019, $1.0 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 2.05 years. The weighted-average vesting period may be reduced due to accelerated vesting under the restructuring program. Refer to Note 9 – Restructuring 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, 2018	1,559,312	$ 11.47
Granted	**759,506**	**7.93**
Vested	**(1,692,896)**	**10.70**
Unvested balance at December 31, 2019	**625,922**	**$ 9.04**

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 three years and are deferred into the Company's nonqualified, unfunded deferred compensation plan at the time of vesting. These awards are ultimately paid in cash, 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 $7.87, $9.55 and $16.98 per share for the years ended December 31, 2019, 2018 and 2017, respectively. There was $2.1 million income tax impact for the year ended December 31, 2019, and no tax impact for the years ended December 31, 2018 and 2017.As of December 31, 2019, $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 0.97 years. The weighted-average vesting period may be reduced due to accelerated vesting of awards under the restructuring program. Refer to Note 9 – Restructuring for more information.

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, 2018	42,675	$ 10.47
Granted	**37,779**	**7.87**
Vested and paid	**(46,061)**	**10.06**
Unvested balance at December 31, 2019	**34,393**	**$ 8.16**

Note 13 – 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, 2019, covers four active and suspended participants, or 2%, of QEP's active employees, and 210 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, 2019, the Company made contributions of $5.0 million to the Pension Plan and expects to contribute approximately $4.0 million to the Pension Plan in 2020. 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, 2019, the Company made contributions of $0.5 million to its SERP and expects to contribute approximately $8.6 million in 2020. 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 four active, pension eligible employees, one is also eligible for the Medical Plan when they retire. As of December 31, 2019, 33 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, 2019, the Company made contributions of $0.9 million and expects to contribute approximately $0.2 million of benefits in 2020. At December 31, 2019 and 2018, 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 2018 and 2019 strategic initiatives, including divestitures and corporate restructurings, triggered curtailments related to the Pension Plan, SERP and/or Medical Plan at the closing of the various transactions. Refer to Note 9 – Restructuring for more information. Curtailments were included in "Interest and other income (expense)" and "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations depending on the associated participants triggering the curtailment and are summarized in the following table:

	Year ended December 31,	
Statements of Operations Line	**2019**	2018
Interest and other income (expense)	**$ (1.4)**	$ (0.3)
Net gain (loss) from asset sales, inclusive of restructuring costs	**0.2**	0.2
Total curtailment gain (loss)	**$ (1.2)**	$ (0.1)

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 recognizes 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 $135.2 million and $122.1 million at December 31, 2019 and 2018, 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, 2019 and 2018, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2019 and 2018:

	Pension Plan and SERP benefits		Medical Plan benefits	
	2019	2018	**2019**	2018
Change in benefit obligation	(in millions)			
Benefit obligation at January 1,	**$ 122.1**	$ 130.0	**$ 2.5**	$ 2.9
Service cost	**0.3**	0.8	**—**	—
Interest cost	**4.8**	4.6	**0.1**	0.1
Curtailments	**1.2**	0.1	**—**	—
Benefit payments	**(6.2)**	(5.8)	**(0.9)**	(0.4)
Plan amendments	**—**	—	**—**	—
Actuarial loss (gain)	**13.0**	(7.6)	**0.9**	(0.1)
Benefit obligation at December 31,	**$ 135.2**	$ 122.1	**$ 2.6**	$ 2.5
Change in plan assets				
Fair value of plan assets at January 1,	**$ 93.3**	$ 100.5	**$ —**	$ —
Actual return on plan assets	**21.3**	(7.1)	**—**	—
Company contributions to the plan	**5.5**	5.7	**0.9**	0.4
Benefit payments	**(6.2)**	(5.8)	**(0.9)**	(0.4)
Fair value of plan assets at December 31,	**113.9**	93.3	**—**	—
Underfunded status (current and long-term)	**$ (21.3)**	$ (28.8)	**$ (2.6)**	$ (2.5)
Amounts recognized in balance sheets				
Accounts payable and accrued expenses	**$ (9.2)**	$ (1.1)	**$ (0.2)**	$ (0.2)
Other long-term liabilities	**(12.1)**	(27.7)	**(2.4)**	(2.3)
Total amount recognized in balance sheet	**$ (21.3)**	$ (28.8)	**$ (2.6)**	$ (2.5)
Amounts recognized in AOCI				
Net actuarial loss (gain)	**$ 15.7**	$ 19.4	**$ 0.4**	$ (0.5)
Prior service cost	**—**	0.4	**—**	(0.8)
Total amount recognized in AOCI	**$ 15.7**	$ 19.8	**$ 0.4**	$ (1.3)

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		
	2019	2018	2017	**2019**	2018	2017
Components of net periodic benefit cost	(in millions)					
Service cost	**$ 0.3**	$ 0.8	$ 0.8	**$ —**	$ —	$ —
Interest cost	**4.8**	4.6	4.7	**0.1**	0.1	0.1
Expected return on plan assets	**(5.9)**	(5.8)	(5.4)	**—**	—	—
Curtailment (gain) loss	**2.0**	0.3	0.7	**(0.8)**	(0.2)	—
Settlements	**—**	—	0.2	**—**	—	—
Amortization of prior service costs	**0.4**	0.8	1.0	**—**	(0.3)	(0.3)
Amortization of actuarial loss	**0.5**	0.8	0.5	**—**	—	(0.1)
Periodic expense	**$ 2.1**	$ 1.5	$ 2.5	**$ (0.7)**	$ (0.4)	$ (0.3)
Components recognized in accumulated other comprehensive income						
Current period prior service cost	**$ —**	$ —	$ (0.7)	**$ —**	$ 0.2	$ (2.5)
Current period actuarial (gain) loss	**(2.4)**	5.6	(7.5)	**0.9**	(0.1)	(0.1)
Amortization of prior service cost	**(0.4)**	(0.8)	(1.0)	**0.8**	0.3	0.3
Amortization of actuarial gain (loss)	**(0.5)**	(0.8)	(0.5)	**—**	—	0.1
Loss on curtailment in current period	**(0.8)**	(0.1)	(0.3)	**—**	—	—
Settlements	**—**	—	(0.2)	**—**	—	—
Total amount recognized in accumulated other comprehensive income	**$ (4.1)**	$ 3.9	$ (10.2)	**$ 1.7**	$ 0.4	$ (2.2)

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 2020 is $0.8 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 2020 is less than $0.1 million, which represents amortization of prior service cost recognized and actuarial losses. 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, 2019 and 2018:

	Pension Plan and SERP benefits		Medical Plan benefits	
	2019	2018	**2019**	2018
Discount rate	**3.13%**	4.19%	**3.40%**	4.30%
Rate of increase in compensation[(1)]	**n/a**	3.00%	**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 year ended December 31, 2018, the rate of increase in compensation is only used for the SERP. For the year ended December 31, 2019, there are no longer any eligible participants in the SERP. As such, the rate of increase in compensation is no longer considered an assumption used to calculate the value of 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		
	2019	2018	2017	**2019**	2018	2017
Discount rate	**4.19%**	3.50%	4.00%	**4.30%**	3.60%	4.10%
Expected long-term return on plan assets	**5.70%**	6.00%	6.00%	**n/a**	n/a	n/a
Rate of increase in compensation[(1)]	**3.00%**	3.50%	3.50%	**n/a**	n/a	3.50%

(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 net period benefit cost of the Pension Plan. As such, for the years ended December 31, 2019 and 2018, the rate of increase in compensation is only used for the SERP.

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 2020. 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, 2019 and 2018, respectively:

	December 31, 2019		December 31, 2018	
	Total	**Percentage of total**	Total	Percentage of total
	(in millions, except percentages)			
Cash and short-term investments	**$ 0.6**	**1%**	$ 0.7	1%
Equity securities:				
Domestic	**30.6**	**27%**	20.7	22%
International	**10.5**	**9%**	10.0	11%
Fixed income	**72.2**	**63%**	61.9	66%
Total investments	**$ 113.9**	**100%**	$ 93.3	100%

Expected Benefit Payments
As of December 31, 2019, the following future benefit payments are expected to be paid:

	Pension Plan and SERP benefits	Medical Plan benefits
	(in millions)	
2020	$ 15.1	$ 0.2
2021	$ 8.9	$ 0.2
2022	$ 9.0	$ 0.2
2023	$ 7.6	$ 0.2
2024	$ 7.5	$ 0.1
2025 through 2029	$ 31.8	$ 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, 2019, 2018 and 2017, the Company made contributions of $3.6 million, $5.8 million and $6.0 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,		
	2019	2018	2017
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, 2019, 2018 and 2017, the Company made a discretionary contribution of less than $0.1 million, $0.3 million and $0.4 million, respectively, to active participants of the Pension Plan.

Note 14 – Income Taxes

In December 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.

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,		
	2019	2018	2017
Federal income tax provision (benefit)		(in millions)	
Current	**$ (32.2)**	$ (71.3)	$ 2.1
Deferred	**55.7**	(257.8)	(339.8)
State income tax provision (benefit)			
Current	**(15.1)**	1.5	0.5
Deferred	**(51.4)**	10.2	25.0
Total income tax provision (benefit)	**$ (43.0)**	$ (317.4)	$ (312.2)

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,		
	2019	2018	2017
Federal income taxes statutory rate[1]	**21.0 %**	21.0 %	35.0 %
Increase (decrease) in rate as a result of:			
State income taxes, net of federal income tax benefit	**(2.5)%**	4.1 %	44.3 %
Federal rate change[1]	**— %**	— %	741.3 %
State rate change[2]	**20.9 %**	(2.9)%	2.1 %
Valuation allowance[3]	**(18.0)%**	(1.9)%	(84.4)%
Permanent adjustments[4]	**(7.1)%**	(0.1)%	(0.4)%
Return to provision adjustment	**2.7 %**	(0.1)%	(0.7)%
Uncertain tax provision[5]	**13.6 %**	— %	(7.7)%
AMT Credit Reclass due to NOL Carryback[6]	**— %**	3.8 %	(1.8)%
Effective income tax rate	**30.6 %**	23.9 %	727.7 %

(1) 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.

(2) During the year ended December 31, 2019, the state rate change was primarily the result of the re-measurement of QEP's deferred tax assets and liabilities at a lower blended state tax rate due to exiting the state of Louisiana.

(3) During the year ended December 31, 2019, the Company recognized an additional valuation allowance of $25.3 million on its Louisiana state NOL. The Company does not expect that it will have sufficient taxable income to utilize the state NOL it is carrying forward due to the Haynesville Divestiture. During the years ended December 31, 2018 and 2017, the Company also increased its valuation allowance by $25.5 million and $36.2 million, respectively, against its Louisiana net operating loss as the Company did not forecast sufficient taxable income to utilize the entire net operating loss in Louisiana at December 31, 2018 and 2017.

(4) During the year ended December 31, 2019, the permanent items primarily related to disallowed officer compensation under Section 162(m) of the Internal Revenue Code of $6.1 million and share-based compensation shortfalls of $4.0 million.

(5) During the year ended December 31, 2019, the Company recognized a tax benefit of $19.0 million due to the expiration of the statute of limitations related to the Company's uncertain tax position. During the year ended December 31, 2017 the decrease in the tax rate was due to the federal corporate income tax rate change related to the Tax Legislation.

(6) During the year ended December 31, 2018, QEP agreed to an IRS proposed change to the initial treatment of the 2016 carryback of net operating losses (NOL). This change resulted in a reduction of available NOL carryforwards valued at $75.7 million and an increase in 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,	
	2019	2018
Deferred tax liabilities	(in millions)	
Property, plant and equipment	**$ 592.9**	$ 665.1
Commodity price derivatives	**—**	30.1
Operating lease right-of-use assets	**12.7**	—
Other	**0.9**	2.6
Total deferred tax liabilities	**606.5**	697.8
Deferred tax assets		
NOL and tax credit carryforwards	**$ 337.7**	$ 467.9
State NOL valuation allowance	**(98.8)**	(82.3)
Employee benefits and compensation costs	**22.3**	33.2
Interest carryforward[1]	**45.7**	—
Commodity price derivatives	**3.9**	—
Operating lease liabilities	**14.1**	—
Other	**7.1**	9.8
Total deferred tax assets	**332.0**	428.6
Net deferred income tax liability	**$ 274.5**	$ 269.2
Balance sheet classification		
Deferred income tax liability – noncurrent	**274.5**	269.2
Net deferred income tax liability	**$ 274.5**	$ 269.2

(1) During the year ended December 31, 2019, the amount of interest the Company could deduct was limited under Section 163(j) of the Internal Revenue Code. This interest can be carried forward indefinitely to offset future taxable income within the code limitations.

The tax effected amounts and expiration dates of NOL and tax credit carryforwards at December 31, 2019, are as follows:

	Expiration Dates	Amounts
		(in millions)
State NOL and tax credit carryforwards	2020-2038	**$ 114.7**
U.S. NOL[1]	2037-Indefinite	**182.1**
U.S. alternative minimum tax credit	Indefinite	**37.1**
General business credits	2036-2037	**3.8**
Total NOL and tax credit carryforwards		**$ 337.7**

(1) Federal NOL's 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 NOL deduction). Of the Company's U.S. NOL, $54.5 million has an indefinite carryforward period but its use is limited to 80% of taxable income.

The Company assesses the available evidence to determine if sufficient future taxable income will be generated to use the existing deferred tax assets. The Company maintains a valuation allowance to offset the uncertain realization of certain of its state NOL's. The Company had a valuation allowance of $98.8 million and $82.3 million for the years ended December 31, 2019 and 2018, respectively, for state NOL's outside of our current core operations and primarily relate to state NOL's in Colorado, Louisiana, Utah and Oklahoma. Due to the various divestitures over the last several years, and focus of our operations, we do not expect to have sufficient taxable income in these states to utilize the NOL's we are carrying forward.

The Tax Legislation eliminated corporate AMT which allowed QEP 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 received $73.9 million of AMT credit refunds in 2019 and anticipates it will realize approximately $74.6 million in AMT credit refunds over the next three years with $37.5 million expected to be realized in 2020 for tax years 2018 and 2019, which is shown in "Income tax receivable" with the remaining $37.1 million included in "Deferred income taxes" on the Consolidated Balance Sheet as of December 31, 2019.

Pursuant to Section 382 and 383 of the Internal Revenue Code, utilization of the Company’s NOL's and credits may be subject to annual limitations in the event of any significant future changes in its ownership structure. These annual limitations may result in the expiration of NOL's and credits prior to utilization.

The Company files income tax returns in the U.S. federal jurisdiction and various state jurisdictions. For federal tax purposes, the Company has been a participant in the IRS Compliance Assurance Process through the 2018 tax year, which provides examination of the tax return prior to filing. Generally, for state tax purposes, the Company’s 2016 through 2018 tax years remain open for examination by the taxing authorities under a three-year statute of limitations. Should the Company utilize any of its state loss carryforwards, their carryforward losses would be subject to examination.

Unrecognized Tax Benefit

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. As of December 31, 2018, 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.

During the year ended December 31, 2019, the statute of limitations related to the Company's uncertain tax position expired, and upon expiration, the Company recognized a $19.0 million tax benefit as well as recorded a $4.1 million reduction in "Interest expense" and a $2.5 million reduction in "General and administrative" expense on the Consolidated Statements of Operations related to accrued interest and penalties that were recorded in prior periods. During the years ended December 31, 2018 and 2017, the Company incurred $0.7 million of estimated interest expense 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, 2019 and 2018:

	Unrecognized Tax Benefits	
	2019	2018
	(in millions)	
Balance as of January 1,	**$ 19.0**	$ 19.0
Recognized tax benefits	**(19.0)**	—
Balance as of December 31,	**$ —**	$ 19.0

Note 15 – Quarterly Financial Information (unaudited)

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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2019	(in millions, except per share amounts or otherwise specified)				
Revenues	**$ 280.6**	**$ 296.2**	**$ 307.5**	**$ 321.9**	**$ 1,206.2**
Operating income (loss)	**$ (15.8)**	**$ 72.3**	**$ 52.1**	**$ 48.9**	**$ 157.5**
Net income (loss)	**$ (116.7)**	**$ 48.8**	**$ 81.0**	**$ (110.4)**	**$ (97.3)**
Net gain (loss) from asset sales, inclusive of restructuring costs and impairment	**$ (18.2)**	**$ 17.8**	**$ (2.1)**	**$ 1.4**	**$ (1.1)**
Per share information					
Basic EPS	**$ (0.49)**	**$ 0.20**	**$ 0.34**	**$ (0.46)**	**$ (0.41)**
Diluted EPS	**$ (0.49)**	**$ 0.20**	**$ 0.34**	**$ (0.46)**	**$ (0.41)**
Production information					
Total equivalent production (Mboe)	**7,806.3**	**7,534.7**	**8,404.0**	**8,465.3**	**32,210.3**
2018					
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

Note 16 – 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,	
	2019	2018
	(in millions)	
Proved properties	**$ 9,574.9**	$ 12,140.7
Unproved properties, net	**599.1**	759.1
Total proved and unproved properties	**10,174.0**	12,899.8
Accumulated depreciation, depletion and amortization	**(5,250.5)**	(7,450.5)
Net capitalized costs	**$ 4,923.5**	$ 5,449.3

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 $12.2 million and ARO additions and revisions of $1.2 million during the year ended December 31, 2019. The costs incurred for the development of reserves that were classified as proved undeveloped were approximately $426.1 million in 2019, $606.5 million in 2018 and $389.3 million in 2017.

	Year Ended December 31,		
	2019	2018	2017
	(in millions)		
Proved property acquisitions	**$ 1.5**	$ 39.1	$ 269.6
Unproved property acquisitions	**2.0**	25.8	532.4
Other acquisitions	**—**	0.8	13.2
Exploration costs (capitalized and expensed)	**0.1**	0.3	32.7
Development costs	**556.2**	1,133.1	1,189.3
Total costs incurred	**$ 559.8**	$ 1,199.1	$ 2,037.2

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,		
	2019	2018	2017
	(in millions)		
Revenues	**$ 1,200.6**	$ 1,920.3	$ 1,548.1
Production costs	**361.9**	507.3	675.4
Exploration expenses	**0.1**	0.3	22.0
Depreciation, depletion and amortization	**528.5**	836.4	735.1
Impairment	**—**	1,560.9	72.3
Total expenses	**890.5**	2,904.9	1,504.8
Income (loss) before income taxes	**310.1**	(984.6)	43.3
Income tax benefit (expense)	**(69.5)**	243.2	(16.0)
Results of operations from producing activities excluding allocated corporate overhead and interest expenses	**$ 240.6**	$ (741.4)	$ 27.3

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, 2019, 2018 and 2017. 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, 2019, 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, 2019, 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, 2017, 2018 and 2019 are as follows:

	Oil and condensate	Gas	NGL	Total[13]
	(MMbbl)	(Bcf)	(MMbbl)	(MMboe)
Balance at December 31, 2016	238.6	2,553.8	67.2	731.4
Revisions of previous estimates[1]	3.7	12.5	(3.1)	2.7
Extensions and discoveries[2]	59.1	101.9	10.4	86.4
Purchase of reserves in place[3]	46.6	125.5	8.7	76.3
Sale of reserves in place[4]	(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[5]	2.1	314.0	6.7	61.0
Extensions and discoveries[6]	57.1	56.5	9.8	76.3
Purchase of reserves in place[7]	8.2	7.9	1.3	10.9
Sale of reserves in place[8]	(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
Revisions of previous estimates[9]	**(94.9)**	**(23.0)**	**(8.7)**	**(107.3)**
Extensions and discoveries[10]	**33.6**	**40.0**	**7.4**	**47.6**
Purchase of reserves in place[11]	**3.6**	**4.0**	**0.7**	**4.9**
Sale of reserves in place[12]	**(4.9)**	**(1,102.2)**	**(0.3)**	**(188.9)**
Production	**(21.6)**	**(33.1)**	**(5.1)**	**(32.2)**
Balance at December 31, 2019	**254.9**	**373.3**	**65.2**	**382.3**
Proved developed reserves				
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
Balance at December 31, 2019	**117.5**	**217.0**	**36.7**	**190.4**
Proved undeveloped reserves				
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
Balance at December 31, 2019	**137.4**	**156.3**	**28.5**	**191.9**

(1) 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.

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

(3) 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.

(4) Sale of reserves in place in 2017 was primarily related to QEP's Pinedale Divestiture as discussed in Note 3 – Acquisitions and Divestitures.

(5) 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.

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

(7) 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.

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

(9) Revisions of previous estimates in 2019 totaling 107.3 MMboe of negative revisions includes 44.5 MMboe of negative PUD revisions as a result of changes to the development sequence in the Permian Basin, to maximize capital efficiency (see offset in extensions and discoveries footnote 10 below); 25.8 MMboe of PUD removals, primarily in the Williston Basin, that will not be developed within five years of the initial date of booking due to the reduction in future capital expenditures; 17.0 MMboe of negative revisions related to pricing, primarily driven by lower oil prices; 13.7 MMboe of negative performance revisions, primarily associated with updated volume projections for high-density wells and certain undrilled locations in the Permian Basin; 10.9 MMboe of other negative revisions, partially offset by 4.6 MMboe of positive revisions related to lower operating costs.

(10) Extensions and discoveries in 2019 primarily related to new PUD locations in the Permian Basin due to changes in the development sequence in the Permian Basin to maximize capital efficiency. See partial offset in revisions to previous estimates in footnote 9 above.

(11) Purchase of reserves in place in 2019 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 2019 was primarily related to QEP's Haynesville 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, 2019, 2018 and 2017, 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 2019, 2018 and 2017, 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,		
	2019	2018	2017
Average benchmark price per unit:			
Oil price (per bbl)	**$ 55.51**	$ 65.56	$ 51.34
Gas price (per MMBtu)	**$ 2.58**	$ 3.10	$ 2.98

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 $435.0 million in 2020, $458.6 million in 2021 and $449.5 million in 2022. 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 condensate 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,		
	2019	2018	2017
		(in millions)	
Future cash inflows	**$ 14,447.6**	$ 26,482.6	$ 22,028.9
Future production costs	**(6,070.6)**	(9,539.9)	(9,074.2)
Future development costs[1]	**(2,275.2)**	(4,441.5)	(4,726.0)
Future income tax expenses[2]	**(845.8)**	(2,553.6)	(1,439.1)
Future net cash flows	**5,256.0**	9,947.6	6,789.6
10% annual discount for estimated timing of net cash flows	**(2,579.7)**	(4,991.9)	(3,692.3)
Standardized measure of discounted future net cash flows	**$ 2,676.3**	$ 4,955.7	$ 3,097.3

(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, 2019, 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,		
	2019	2018	2017
	(in millions)		
Balance at January 1,	**$ 4,955.7**	$ 3,097.3	$ 1,928.0
Sales of oil and condensate, gas and NGL produced, net of production costs	**(838.7)**	(1,413.0)	(872.7)
Net change in sales prices and in production (lifting) costs related to future production	**(1,988.6)**	1,632.5	1,457.2
Net change due to extensions and discoveries	**220.9**	692.6	556.8
Net change due to revisions of quantity estimates	**(2,079.2)**	732.0	9.9
Net change due to purchases of reserves in place	**34.2**	117.0	342.7
Net change due to sales of reserves in place	**(617.8)**	(369.6)	(504.7)
Previously estimated development costs incurred during the period	**460.8**	735.6	475.4
Changes in estimated future development costs	**1,064.7**	(28.3)	(283.4)
Accretion of discount	**622.8**	375.4	235.7
Net change in income taxes	**841.5**	(615.7)	(227.4)
Other	**—**	(0.1)	(20.2)
Net change	**(2,279.4)**	1,858.4	1,169.3
Balance at December 31,	**$ 2,676.3**	$ 4,955.7	$ 3,097.3

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, 2019. Based on such evaluation, such officers have concluded that, as of December 31, 2019, 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, 2019, 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, 2019, 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, 2019. 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, 2019, 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 director nominees 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, 2019 (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 May 14, 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 May 17, 2019).
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	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)
4.3	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)
4.4	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)
4.5	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)
4.6	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)
4.7	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)
4.8*	Description of the Company's Securities
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)
10.2*	First Amendment to Credit Agreement, dated as of July 6, 2012
10.3	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)
10.4	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)
10.5	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)
10.6	Fifth Amendment to the 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)
10.7	Sixth Amendment to the 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)
10.8	Seventh Amendment to the 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)
10.9+	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)
10.10+	Amended and Restated QEP Resources, Inc. Deferred Compensation Wrap Plan, dated May 15, 2017 (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 July 26, 2017)
10.11+	Amended and Restated QEP Resources, Inc. Deferred Compensation Plan for Directors, dated July 24, 2017 (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 July 26, 2017)
10.12+	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)
10.13+	Amendment Number One to the 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)

10.14+	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)
10.15+	Amendment Number One to 2010 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)
10.16+	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)
10.17+	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)
10.18+	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)
10.19+	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)
10.20+	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)
10.21+	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)
10.22+	Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to executive officers 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)
10.23+	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)
10.24+	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)
10.25+	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 Company's Annual Report on Form 10-K, filed with the Securities and Exchange Commission on February 28, 2018)
10.26+	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 Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on July 25, 2018)
10.27*+	Form of Restricted Stock Agreement for restricted stock granted to non-employee directors under the 2018 Long-Term Incentive Plan
10.28+	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)
10.29+	Form of Performance Share Unit Award Agreement for performance share units granted to executive officers under the 2012 Cash Incentive Plan (incorporated by reference to Exhibit 10.33 to the Company's Annual Report on Form 10-5, filed with the Securities and Exchange Commission on February 22, 2017)
10.30+	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 Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on July 25, 2018)
10.31+	Form of Retention Letter, dated December 5, 2018, between the Company and certain executive officers (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 December 6, 2018)
10.32	Letter Agreement, dated August 6, 2019, by and between QEP Resources, Inc. and Elliott Management Corporation (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 August 7, 2019)

10.33+	Letter Agreement, dated February 19, 2019, with Richard J. Doleshek (incorporated by reference to Exhibit 10.35 to the Company's Annual Report on Form 10-K, filed with the Securities and Exchange Commission on February 20, 2019)
10.34+	Form of Deferred Share Award Agreement for shares of common stock granted to non-employee directors under the 2018 Long-Term Incentive Plan and for deferral of receipt of such shares in accordance with the terms of the Director Deferred Compensation Plan (incorporated by reference to Exhibit 10.1 to the Company' Quarterly Report on form 10-Q, filed with the Securities and Exchange Commission on August 7, 2019)
10.35+	Executive Severance Compensation Plan – CIC, as Amended and Restated Effective as of August 7, 2019 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K, filed by the Company with the Securities and Exchange Commission on August 7, 2019)
10.36+	Separation Agreement, dated October 23 2019, by and between QEP Resources, Inc. and Richard J. Doleshek (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 23, 2019)
16.1	Letter regarding Change in Certifying Accountant (incorporated by reference to Exhibit 16.1 to the Company's Current Report on Form 8K, filed with the Securities and Exchange Commission on October 23, 2019)
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 William J. Buese, QEP Resources, Inc. Vice President, Chief Financial Officer, Treasurer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification signed by Timothy J. Cutt and William J. Buese, QEP Resources, Inc. President and Chief Executive Officer and Vice President, Chief Financial Officer and Treasurer 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

* 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 26, 2020.

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 26, 2020.

/s/ Timothy J. Cutt Timothy J. Cutt	President and Chief Executive Officer (Principal Executive Officer)
/s/ William J. Buese William J. Buese	Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ Alice B. Ley Alice B. Ley	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)
*David Trice	Chair of the Board; Director
*Timothy J. Cutt	Director
*Philips S. Baker, Jr.	Director
*Julie A. Dill	Director
*Robert F. Heinemann	Director
*Joseph N. Jaggers	Director
*Michael J. Minarovic	Director
*M. W. Scoggins	Director
*Mary Shafer-Malicki	Director
*Barth E. Whitham	Director

February 26, 2020

*By /s/ Timothy J. Cutt
Timothy J. Cutt, Attorney in Fact

Exhibit 4.8

DESCRIPTION OF THE REGISTRANT'S SECURITIES

REGISTERED PURSUANT TO SECTION 12 OF THE

SECURITIES EXCHANGE ACT OF 1934

As of February [25], 2020, QEP Resources, Inc. has one class of securities, our common stock, par value $0.01 per share (our "common stock"), registered under Section 12 of the Securities Exchange Act of 1934, as amended.

The following description of our common stock is a summary and does not purport to be complete. It is subject to and qualified in its entirety by reference to our Amended and Restated Certificate of Incorporation, dated as of May 15, 2018 (our "Certificate of Incorporation"), and our Amended and Restated Bylaws, dated as of May 14, 2019 (our "Bylaws"), each of which are incorporated by reference as an exhibit to the Annual Report on Form 10-K of which this Exhibit 4.[8] is a part. We encourage you to read our Certificate of Incorporation, our Bylaws and the applicable provisions of the General Corporation Law of the State of Delaware ("DGCL") for additional information.

Authorized Capital Shares. We are authorized to issue up to 500,000,000 shares of common stock and 10,000,000 shares of preferred stock, $0.01 par value per share.

Dividends. The holders of our common stock are entitled to receive dividends when, as and if declared by our board of directors, out of funds legally available for their payment subject to the rights of holders of any preferred stock outstanding.

Voting Rights. The holders of our common stock are entitled to one vote per share on all matters submitted to a vote of stockholders and do not have cumulative voting rights. Our board of directors is not classified and each member is elected annually. Our Bylaws provide for directors in uncontested director elections to be elected by a simple majority vote. Except as otherwise provided by the rules and regulations applicable to us or our securities, all other matters submitted to a vote of stockholders are determined by the affirmative vote of a majority of the outstanding voting power of the shares entitled to vote on the matter.

Rights Upon Liquidation. In the event of our voluntary or involuntary liquidation, dissolution or winding up, the holders of our common stock will be entitled to share equally in any of our assets available for distribution after the payment in full of all debts and distributions and after the holders of all series of outstanding preferred stock have received their liquidation preferences in full.

Listing. Our common stock is listed on The New York Stock Exchange under the trading symbol "QEP."

Miscellaneous. The outstanding shares of our common stock are fully paid and nonassessable. The holders of our common stock are not entitled to preemptive or redemption

rights and our common stock has no sinking fund provision. Shares of our common stock are not convertible into shares of any other class of capital stock.

Delaware Anti-Takeover Law. We are subject to Section 203 of the DGCL, an anti-takeover law. In general, the statute prohibits a publicly held Delaware corporation from engaging in a business combination with an "interested stockholder" for a period of three years after the date of the transaction in which the person became an interested stockholder. A "business combination" includes a merger, sale of 10% or more of a corporation's assets and certain other transactions resulting in a financial benefit to the interested stockholder. For purposes of Section 203, an "interested stockholder" is defined to include any person that is:

- the owner of 15% or more of the outstanding voting stock of the corporation;
- an affiliate or associate of the corporation and was the owner of 15% or more of the corporation's voting stock outstanding, at any time within three years immediately before the relevant date; and
- an affiliate or associate of the persons described in the foregoing bullet points.

However, the above provisions of Section 203 do not apply if:

- the corporation's board approves the transaction that resulted in the stockholder becoming an interested stockholder before the date of that transaction;
- after the completion of the transaction that resulted in the stockholder becoming an interested stockholder, that stockholder owned at least 85% of the corporation's voting stock outstanding at the time the transaction commenced, excluding shares owned by the corporation's officers and directors; or
- on or subsequent to the date of the transaction, the business combination is approved by the corporation's board and authorized at a meeting of the corporation's stockholders by an affirmative vote of at least two-thirds of the outstanding voting stock not owned by the interested stockholder.

Stockholders may, by adopting an amendment to the corporation's certificate of incorporation or bylaws, elect for the corporation not to be governed by Section 203, which amendment will generally be effective 12 months after adoption. Neither our amended and restated certificate of incorporation nor our amended and restated bylaws exempts us from the restrictions imposed under Section 203. It is anticipated that the provisions of Section 203 may encourage companies interested in acquiring us to negotiate in advance with our board.

Exhibit 10.2

FIRST AMENDMENT TO CREDIT AGREEMENT

This **FIRST AMENDMENT TO CREDIT AGREEMENT** (this "Amendment") is made and entered into as of July 6, 2012, by and among **QEP RESOURCES, INC.**, a Delaware corporation (the "Borrower"), the Lenders named on the signature pages hereto, and WELLS FARGO BANK, NATIONAL ASSOCIATION, as Administrative Agent for the Lenders (in such capacity, the "Administrative Agent"), L/C Issuer and Swing Line Lender.

W I T N E S S E T H:

WHEREAS, the Borrower, the Lenders and the Administrative Agent are parties to that certain Credit Agreement dated as of August 25, 2011 (the "Credit Agreement"); and

WHEREAS, the Borrower and the undersigned Lenders have agreed to amend the Credit Agreement as set forth in ***Section 2*** below.

NOW, THEREFORE, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto hereby agree as follows:

1. **Definitions.** Unless otherwise defined in this Amendment, terms used in this Amendment which are defined in the Credit Agreement shall have the meanings assigned to such terms in the Credit Agreement. The interpretive provisions set forth in *Section 1.02* of the Credit Agreement shall apply to this Amendment.

2. **Amendments to the Credit Agreement.** Subject to satisfaction of the condition set forth in ***Section 3*** hereof, the Credit Agreement is hereby amended as follows:

(a) The definition of "Interest Period" in *Section 1.01* of the Credit Agreement (Defined Terms) is hereby amended by replacing the phrase "one, two or three weeks" with the phrase "one or two weeks" in *clause (a)* thereof.

(b) *Section 2.02(a)* of the Credit Agreement (Borrowings, Conversions and Continuations of Loans) is hereby amended by replacing the phrase "one, two or three weeks" with the phrase "one or two weeks".

(c) *Section 3.04(b)* of the Credit Agreement (Increased Cost and Reduced Return; Capital Adequacy; Reserves on Eurodollar Rate Loans) is hereby amended by replacing the phrase "regarding capital requirements" with the phrase "regarding capital or liquidity requirements,".

(d) *Section 5.07* of the Credit Agreement (Other Obligations and Restrictions) is hereby amended by (i) replacing the clause "Neither the Borrower nor any of its Restricted Subsidiaries" with the clause "As of the Closing Date, neither the Borrower nor any of its Restricted Subsidiaries" in the first sentence thereof and (ii) replacing the clause "Except as shown in the Audited Financial Statements or disclosed on Schedule 5.07" with the clause "As of the Closing Date, except as shown in the Audited Financial Statements or disclosed on Schedule 5.07" in the second sentence thereof.

(e) *Section 6.01(b)* of the Credit Agreement (Books, Financial Statements and Reports) is hereby amended by replacing the phrase "after the end of each fiscal quarter" with the phrase "after the end of each of the first three fiscal quarters of the Borrower".

3. **Conditions of Effectiveness.** The effectiveness of this Amendment is subject to the condition precedent that the Administrative Agent shall have received counterparts of this Amendment executed by the Borrower and the Required Lenders.

4. **Representations and Warranties.** The Borrower hereby represents and warrants that:

(a) this Amendment has been duly authorized, executed and delivered by the Borrower and this Amendment and the Credit Agreement as modified hereby each constitutes a legal, valid and binding obligation of the Borrower enforceable in accordance with its respective terms, except as such enforcement may be limited by bankruptcy, insolvency or similar Laws of general application relating to the enforcement of creditors' rights or by general principles of equity, regardless of whether considered in a proceeding in equity or at law;

(b) the representations and warranties contained in *Article V* of the Credit Agreement are true and correct in all material respects (except that such materiality qualifier shall not be applicable to representations and warranties that already are qualified or modified by materiality in the text thereof) on and as of the date hereof, except to the extent that such representations and warranties specifically refer to an earlier date, in which case they shall be true and correct as of such earlier date, and except that the representations and warranties contained in *clauses (a)* and *(b)* of *Section 5.06* of the Credit Agreement shall be deemed to refer to the most recent statements furnished pursuant to clauses *(a)* and *(b)*, respectively, of *Section 6.01*; and

(c) no Default or Event of Default exists on and as of the date hereof.

5. **Effect of Amendment.** This Amendment, except as expressly provided herein, shall not be deemed to be a consent to the modification or waiver of any other term or condition of the Credit Agreement. Except as otherwise expressly provided by this Amendment, all of the terms, conditions and provisions of the Credit Agreement shall remain the same and the Credit Agreement, as amended hereby, shall continue in full force and effect. From and after the date hereof, each reference in the Credit Agreement, including the schedules and exhibits thereto and the other documents delivered in connection therewith, to the "Credit Agreement," "this Agreement," "hereunder," "hereof," "herein," or words of like import, shall mean and be a reference to the Credit Agreement as amended hereby.

6. **Miscellaneous.** This Amendment shall for all purposes be construed in accordance with and governed by the laws of the State of New York. The captions in this Amendment are for convenience of reference only and shall not define or limit the provisions hereof. This Amendment may be executed in one or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument. Delivery of an executed counterpart of this Amendment by facsimile or in electronic form shall be effective as the delivery of a manually executed counterpart. This Amendment shall be a "Loan Document" as defined in the Credit Agreement.

7. **Entire Agreement.** THE CREDIT AGREEMENT (AS AMENDED BY THIS AMENDMENT) AND THE OTHER LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT BETWEEN THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS OR SUBSEQUENT ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN THE PARTIES.

[SIGNATURES PAGES FOLLOW]

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be duly executed and delivered by their proper and duly authorized officers effective as of the date first written above.

QEP RESOURCES, INC., as the Borrower

By: /s/ Richard J. Doleshek
Name: Richard J. Doleshek
Title: Executive VP & CFO

WELLS FARGO BANK, NATIONAL ASSOCIATION, as Administrative Agent, L/C Issuer, Swing Line Lender and a Lender

By: /s/ Leanne S. Phillips
Name: Leanne S. Phillips
Title: Director

BMO CAPITAL MARKETS FINANCING, INC., as a Lender

By: /s/ Kevin Utsey
Name: Kevin Utsey
Title: Director

DEUTSCHE BANK TRUST COMPANY AMERICAS, as a Lender

By: /s/ Marcus M. Tarkington
Name: Marcus M. Tarkington
Title: Director

By: /s/ Evelyn Thierry
Name: Evelyn Thierry
Title: Director

JPMORGAN CHASE BANK, N.A., as a Lender

By: /s/ Marshall Trenckmann
Name: Marshall Trenckmann
Title: Vice President

U.S. BANK NATIONAL ASSOCIATION, as a Lender

By: /s/ John C. Lozano
Name: John C. Lozano
Title: Vice President

AMEGY BANK NATIONAL ASSOCIATION, as a Lender

By: /s/ Charles Troeger
Name: Charles Troeger
Title: Vice President

BRANCH BANKING AND TRUST COMPANY, as a Lender

By: /s/ Parul June
Name: Parul June
Title: Vice President

THE BANK OF TOKYO-MITSUBISHI UFJ, LTD., as a Lender

By: /s/ Maria Ferradas
Name: Maria Ferradas
Title: Vice President

CIBC, INC., as a Lender

By: /s/ Trudy Nelson
Name: Trudy Nelson
Title: Authorized Signatory

By: /s/ Richard Antl
Name: Richard Antl
Title: Authorized Signatory

CITIBANK, N.A., as a Lender

By: /s/ John Miller
Name: John Miller
Title: Vice President

COMERICA BANK, as a Lender

By: /s/ Katya Evseev
Name: Katya Evseev
Title: Corporate Banking Officer

COMPASS BANK, as a Lender

By: /s/ James Neblett
Name: James Neblett
Title: Vice President

CREDIT AGRICOLE CORPORATE AND INVESTMENT BANK, as a Lender

By: /s/ Michael D. Willis
Name: Michael D. Willis
Title: Managing Director

By: /s/ Tom Byargeon
Name: Tom Byargeon
Title: Managing Director

DNB BANK ASA, GRAND CAYMAN BRANCH, as a Lender

By: /s/ Giacomo Landi
Name: Giacomo Landi
Title: Vice President

By: /s/ Andrea Ozbolt
Name: Andrea Ozbolt
Title: Vice President

EXPORT DEVELOPMENT CANADA, as a Lender

By: /s/ Richard Leong
Name: Richard Leong
Title: Asset Manager

By: /s/ Talai M. Kairouz
Name: Talai M. Kairouz
Title: Senior Asset Manager

GOLDMAN SACHS BANK USA, as a Lender

By: /s/ Michelle Latzoni
Name: Michelle Latzoni
Title: Authorized Signatory

MORGAN STANLEY BANK, N.A., as a Lender

By: /s/ Dmitriy Barskiy
Name: Dmitriy Barskiy
Title: Authorized Signatory

SUNTRUST BANK, as a Lender

By: /s/ Yann Pirio
Name: Yann Pirio
Title: Director

TORONTO DOMINION (NEW YORK) LLC, as a Lender

By: /s/ Kelly Hundal
Name: Kelly Hundal
Title: Authorized Signatory

Exhibit 10.27

QEP RESOURCES, INC.
2018 LONG-TERM INCENTIVE PLAN

RESTRICTED STOCK AGREEMENT

THIS RESTRICTED STOCK AGREEMENT (the "Agreement") is made as of _____ (the "Effective Date"), between QEP Resources, Inc., a Delaware corporation (the "Company"), and _____ ("Grantee"). Terms not defined herein shall have the meanings ascribed to them in the QEP Resources, Inc. 2018 Long-Term Incentive Plan, as it may be amended from time to time (the "Plan").

1. Grant of Restricted Stock. Subject to the terms and conditions of this Agreement and the Plan, for good and valuable consideration, on the Effective Date, the Company hereby issues to Grantee _____ shares of the Company's Common Stock, $.01 par value, subject to certain restrictions thereon (the "Restricted Stock").

2. Restrictions. Shares of Restricted Stock may not be sold, assigned, transferred by gift or otherwise, pledged, hypothecated, or otherwise disposed of, by operation of law or otherwise, and shall be subject to forfeiture in accordance with the provisions of Section 5, below, until Grantee becomes vested in the Restricted Stock. Upon vesting, the restrictions in this Section 2 shall lapse, the Restricted Stock shall no longer be subject to forfeiture, and Grantee may transfer shares of Restricted Stock in accordance with the Securities Act of 1933 and other applicable securities laws.

3. Enforcement of Restrictions. To enforce the restrictions set forth in Section 2, shares of Restricted Stock will be held in electronic form in an account by the Company's transfer agent or other designee until the restrictions set forth in Section 2 have lapsed with respect to such shares, or such shares are forfeited, whichever is earlier.

4. Vesting; Lapse of Restrictions. Except as provided otherwise in this Agreement, the Restricted Stock shall vest on the one-year anniversary of the Effective Date.

If the Vesting Date falls on a day when the New York Stock Exchange (NYSE) is closed, the Vesting Date will occur on the next day that the NYSE is open. In the event that the Vesting Date falls on a day when trading in the Common Stock has been suspended, the Vesting Date will occur on the next full day after trading resumes.

5. Termination of Service; Forfeiture of Restricted Stock.

(a) Death, Disability, Retirement or Failure to be Renominated. If Grantee ceases to be a member of the Board on account of death, Disability, mandatory retirement at age 72, or failure to be renominated for any reason (including at Grantee's or the Company's request) other than failure to adequately perform his or her duties as a member of the Board, the Restricted Stock, to the extent not yet vested, shall vest in full and the restrictions set forth in Section 2 shall lapse in their entirety.

(b) Termination in Connection with a Change in Control. If, in connection with a Change in Control of the Company, Grantee's directorship with the Company terminates for any reason,

the Restricted Stock, to the extent not yet vested, shall vest in full and the restrictions set forth in Section 2 shall lapse in their entirety.

(c) Other Terminations. Except as provided in Section 5(a) and Section 5(b) above, if Grantee's directorship with the Company terminates for any reason, Grantee shall forfeit all shares of Restricted Stock that are not yet vested at the time of such termination.

(d) Manner of Forfeiture. Any shares of Restricted Stock forfeited by Grantee pursuant to this Section 5 shall promptly be transferred to the Company without the payment of any consideration therefor, and Grantee, or Grantee's attorney-in-fact, shall execute all documents and take all actions as shall be necessary or desirable to promptly effectuate such transfer. On and after the time at which any shares are required to be transferred to the Company, the Company shall not pay any dividend to Grantee on account of such shares or permit Grantee to exercise any of the privileges or rights of a stockholder with respect to the shares but shall, in so far as permitted by law, treat the Company as owner of the shares.

6. Effect of Prohibited Transfer. If any transfer of Restricted Stock is made or attempted to be made contrary to the terms of this Agreement, the Company shall have the right to acquire for its own account, without the payment of any consideration therefor, such shares from the owner thereof or his or her transferee, at any time before or after such prohibited transfer. In addition to any other legal or equitable remedies it may have, the Company may enforce its rights to specific performance to the extent permitted by law and may exercise such other equitable remedies then available to it. The Company may refuse for any purpose to recognize any transferee who receives shares contrary to the provisions of this Agreement as a stockholder of the Company and may retain and/or recover all dividends on such shares that were paid or payable subsequent to the date on which the prohibited transfer was made or attempted.

7. Rights of a Stockholder. Subject to the restrictions imposed by Section 2 and the terms of any other relevant sections hereof, Grantee shall have all of the voting, dividend, liquidation and other rights of a stockholder with respect to the Restricted Stock.

8. Adjustments to Restricted Stock.

(a) Adjustment by Merger, Stock Split, Stock Dividend, Etc. If the Common Stock, as presently constituted, shall be changed into or exchanged for a different number or kind of shares of stock or other securities of the Company or of another corporation (whether by reason of merger, consolidation, recapitalization, reclassification, stock split, spinoff, combination of shares or otherwise), or if the number of such shares of stock shall be increased through the payment of a stock dividend, then there shall be substituted for or added to each share of Restricted Stock, the number and kind of shares of stock or other securities into which each outstanding share of Restricted Stock shall be so changed or for which each such share shall be exchanged or to which each such share shall be entitled, as the case may be.

(b) Other Distributions and Changes in the Stock. In the event there shall be any other change affecting the number or kind of the outstanding shares of the Common Stock, or any stock or other securities into which the stock shall have been changed or for which it shall have been exchanged, then if the Committee shall, in its sole discretion, determine that the change equitably requires an

adjustment in the shares of Restricted Stock, an adjustment shall be made in accordance with such determination.

(c) General Adjustment Rules. All adjustments relating to stock or securities of the Company shall be made by the Committee, whose determination in that respect shall be final, binding and conclusive. Fractional shares resulting from any adjustment to the Restricted Stock pursuant to this Section 8 may be settled as the Committee shall determine. Notice of any adjustment shall be given to Grantee.

(d) Reservation of Rights. The issuance of Restricted Stock shall not affect in any way the right or power of the Company to make adjustments, reclassifications, reorganizations or changes of its capital or business structure, to merge, to consolidate, to dissolve, to liquidate or to sell or transfer all or any part of its business or assets.

9. Tax Consequences. Set forth below is a brief summary as of the date of grant of certain United States federal income tax consequences of the award of the Restricted Stock. THIS SUMMARY DOES NOT ADDRESS SPECIFIC STATE, LOCAL OR FOREIGN TAX CONSEQUENCES THAT MAY BE APPLICABLE TO GRANTEE. GRANTEE UNDERSTANDS THAT THIS SUMMARY IS NECESSARILY INCOMPLETE, AND THE TAX LAWS AND REGULATIONS ARE SUBJECT TO CHANGE.

Unless Grantee makes a Section 83(b) election as described below, Grantee shall recognize ordinary income at the time or times the shares of Restricted Stock are released from the restrictions in Section 2, in an amount equal to the Fair Market Value of the shares on such date(s) less the amount paid, if any, for such shares.

10. Section 83(b) Election. Grantee hereby acknowledges that he or she has been informed that he or she may file with the Internal Revenue Service, within thirty (30) days of the Effective Date, an election pursuant to Section 83(b) of the Internal Revenue Code of 1986, as amended, to be taxed as of the Effective Date on the amount by which the Fair Market Value of the Restricted Stock as of such date exceeds the price paid for such shares, if any.

IF GRANTEE CHOOSES TO FILE AN ELECTION UNDER SECTION 83(b) OF THE CODE, GRANTEE ACKNOWLEDGES THAT IT IS GRANTEE'S SOLE RESPONSIBILITY AND NOT THE COMPANY'S TO FILE TIMELY THE ELECTION UNDER SECTION 83(b) OF THE CODE, EVEN IF GRANTEE REQUESTS THE COMPANY OR ITS REPRESENTATIVE TO MAKE THIS FILING ON GRANTEE'S BEHALF.

BY SIGNING THIS AGREEMENT, GRANTEE REPRESENTS THAT HE OR SHE HAS REVIEWED WITH HIS OR HER OWN TAX ADVISORS THE FEDERAL, STATE, LOCAL AND FOREIGN TAX CONSEQUENCES OF THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT AND THAT HE OR SHE IS RELYING SOLELY ON SUCH ADVISORS AND NOT ON ANY STATEMENTS OR REPRESENTATIONS OF THE COMPANY OR ANY OF ITS AGENTS. GRANTEE UNDERSTANDS AND AGREES THAT HE OR SHE (AND NOT THE COMPANY) SHALL BE RESPONSIBLE FOR ANY TAX LIABILITY THAT MAY ARISE AS A RESULT OF THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT.

11. Notices. Any notice required or permitted to be given under this Agreement shall be in writing and shall be given by hand delivery or by first class registered or certified mail, postage prepaid, addressed, if to the Company, to its Corporate Secretary, and if to Grantee, to his or her address now on file with the Company, or to such other address as either may designate in writing. Any notice shall be deemed to be duly given as of the date delivered in the case of personal delivery, or as of the second day after enclosed in a properly sealed envelope and deposited, postage prepaid, in a United States post office, in the case of mailed notice.

12. Amendment. Except as provided herein, this Agreement may not be amended or otherwise modified unless evidenced in writing and signed by the Company and Grantee, and as approved by the Committee. Notwithstanding any provision in this Agreement to the contrary, including Section 13, an amendment to the Plan that would materially and adversely affect Grantee's rights with respect to the award of Restricted Stock granted hereunder will not be effective with respect to such award.

13. Relationship to Plan. This Agreement shall not alter the terms of the Plan. If there is a conflict between the terms of the Plan and the terms of this Agreement, the terms of the Plan shall prevail.

14. Construction; Severability. The section headings contained herein are for reference purposes only and shall not in any way affect the meaning or interpretation of this Agreement. The invalidity or unenforceability of any provision of this Agreement shall not affect the validity or enforceability of any other provision of this Agreement, and each other provision of this Agreement shall be severable and enforceable to the extent permitted by law.

15. Waiver. Any provision contained in this Agreement may be waived, either generally or in any particular instance, by the Committee appointed under the Plan, but only to the extent permitted under the Plan.

16. Entire Agreement; Binding Effect. Once accepted, this Agreement, the terms and conditions of the Plan, and the award of Restricted Stock set forth herein, constitute the entire agreement between Grantee and the Company governing such award of Restricted Stock, and shall be binding upon and inure to the benefit of the Company and to Grantee and to the Company's and Grantee's respective heirs, executors, administrators, legal representatives, successors and assigns.

17. No Rights to Continued Service as a Director. Nothing contained in this Agreement shall be construed as giving Grantee any right to be retained as a member of the Board and this Agreement is limited solely to governing the rights and obligations of Grantee with respect to the Restricted Stock.

18. Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware, without regard to the choice of law principles thereof.

IN WITNESS WHEREOF, the parties have executed this Agreement as of the day and year first above written.

GRANTEE QEP RESOURCES, INC.

by:_____ [Name] [NAME]
[TITLE]

Exhibit 21.1

QEP Resources, Inc.
Subsidiaries of the Company

Name	State of Organization
QEP Energy Company[1]	Delaware
QEP Marketing Company, LLC[2]	Utah
QEP Field Services Company[1]	Delaware
Mustang Springs Oil Terminal, LLC[3]	Delaware
Permian Gathering, LLC[3]	Delaware
QEP Oil & Gas Company, LLC[3]	Delaware
Sakakawea Area Spill Response LLC[4]	Delaware

(1) 100% owned by QEP Resources, Inc.
(2) 100% owned by QEP Energy Company
(3) 100% owned by QEP Marketing Company, LLC
(4) 6% owned by QEP Energy Company

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-223553) and Form S-8 (No. 333-225316) of QEP Resources, Inc. of our report dated February 26, 2020 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Denver, Colorado
February 26, 2020

Exhibit 23.2

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

As independent petroleum engineers, we hereby consent to the reference of our appraisal reports relating to the proved gas and oil reserves of QEP Energy Company in the Annual Report on Form 10-K of QEP Resources, Inc. as of the years ended December 31, 2015, 2016, 2017, 2018 and 2019 incorporated herein by reference into Registration Statement Nos. No. 333-223553 on Form S-3 and No. 333-225316 on Form S-8.

/s/ Ryder Scott Company, L.P.

Ryder Scott Company, L.P.

Denver, Colorado
February 26, 2020

Exhibit 24

POWER OF ATTORNEY

We, the undersigned directors of QEP Resources, Inc., hereby severally constitute Timothy J. Cutt and William J. Buese, and each of them acting alone, our true and lawful attorneys, with full power to them and each of them to sign for us, and in our names in the capacities indicated below, the Annual Report on Form 10-K for 2019 and any and all amendments to be filed with the Securities and Exchange Commission by QEP Resources, Inc., hereby ratifying and confirming our signatures as they may be signed by the attorneys appointed herein to the Annual Report on Form 10-K for 2019 and any and all amendments to such Report.

Witness our hands on the respective dates set forth below.

Signature	Title	Date
/s/ Timothy J. Cutt Timothy J. Cutt	President and Chief Executive Officer Director	2/26/2020
/s/ David A. Trice David A. Trice	Chair of the Board Director	2/26/2020
/s/ Phillips S. Baker, Jr. Phillips S. Baker, Jr.	Director	2/26/2020
/s/ Julie A. Dill Julie A. Dill	Director	2/26/2020
/s/ Robert F. Heinemann Robert F. Heinemann	Director	2/26/2020
/s/ Joseph N. Jaggers Joseph N. Jaggers	Director	2/26/2020
/s/ Michael J. Minarovic Michael J. Minarovic	Director	2/26/2020
/s/ M. W. Scoggins M. W. Scoggins	Director	2/26/2020
/s/ Mary Shafer-Malicki Mary Shafer-Malicki	Director	2/26/2020
/s/ Barth E. Whitham Barth E. Whitham	Director	2/26/2020

Exhibit 31.1

CERTIFICATION

I, Timothy J. Cutt, certify that:

1. I have reviewed this report of QEP Resources, Inc. on Form 10-K for the period ended December 31, 2019;

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

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

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

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

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

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

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

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

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

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

February 26, 2020

/s/ Timothy J. Cutt

Timothy J. Cutt

President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, William J. Buese, certify that:

1. I have reviewed this report of QEP Resources, Inc. on Form 10-K for the period ended December 31, 2019;

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

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

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

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

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

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

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

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

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

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

February 26, 2020

/s/ William J. Buese

William J. Buese

Vice President, Chief Financial Officer and Treasurer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with this report of QEP Resources, Inc. (the Company) on Form 10-K for the period ended December 31, 2019, as filed with the Securities and Exchange Commission on the date hereof (the Report), Timothy J. Cutt, President and Chief Executive Officer of the Company, and William J. Buese, Vice President, Chief Financial Officer and Treasurer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934; and

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

QEP RESOURCES, INC.

February 26, 2020

/s/ Timothy J. Cutt

Timothy J. Cutt
President and Chief Executive Officer

February 26, 2020

/s/ William J. Buese

William J. Buese
Vice President, Chief Financial Officer and Treasurer

Exhibit 99.1

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

January 13, 2020

QEP Energy Company
1050 Seventeenth Street, Suite 800
Denver, Colorado 80265

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of QEP Energy Company (QEP) as of December 31, 2019. The subject properties are located in the states of New Mexico, North Dakota, Texas, and Wyoming. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 13, 2020 and presented herein, was prepared for public disclosure by QEP in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon and gas reserves of QEP as of December 31, 2019.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2019 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
QEP Energy Company
As of December 31, 2019

	Proved			
	Developed			Total
	Producing	Non-producing	Undeveloped	Proved
Net Reserves				
Oil/Condensate - Mbbl	113,434	4,106	137,353	254,893
Plant Products - Mbbl	35,778	897	28,548	65,223
Gas - MMcf	212,053	4,942	156,321	373,316
Income Data ($M)				
Future Gross Revenue	$ 6,313,238	$ 214,620	$ 7,115,715	$ 13,643,573
Deductions	3,196,083	77,339	4,268,339	7,541,761
Future Net Income (FNI)	$ 3,117,155	$ 137,281	$ 2,847,376	$ 6,101,812
Discounted FNI @ 10%	$ 1,941,848	$ 90,913	$ 1,074,248	$ 3,107,009

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of QEP. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion costs, development costs, and certain abandonment costs net of salvage. Certain NGL processing fees are included as “Other” deductions as shown in the cash flow. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 95 percent and gas reserves account for the remaining 5 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

Discount Rate Percent	Discounted Future Net Income ($M) As of December 31, 2019 Total Proved
5	$4,169,001
9	$3,277,775
15	$2,451,672
20	$2,012,998

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined under the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of shut-in and behind pipe status categories.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At QEP's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

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." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not

be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

QEP's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which QEP owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods and analogy. In general, the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis which utilized extrapolations of available historical production and pressure data ending between September and December 2019, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by QEP and were considered sufficient for the purpose thereof. In certain early-life cases, estimates of producing reserves were guided by analogy to older wells with more established decline trends.

Approximately 97 percent of the proved developed non-producing reserves and all of the proved undeveloped reserves included herein were estimated by analogy. The remaining 3 percent of the proved developed non-producing reserves were based on the historical performance of those shut-in wells before going offline. The data utilized from the analogues and the historical performance of the shut-in wells were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

QEP has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by QEP with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by QEP. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our 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.

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 our 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, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

QEP furnished us with the above mentioned average prices in effect on December 31, 2019. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, certain oil transportation fees, and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by QEP. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by QEP to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$55.51/Bbl	$50.37/Bbl
	NGLs	WTI Cushing	$55.51/Bbl	$14.51/Bbl
	Gas	Henry Hub	$2.58/MMBTU	$1.77/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by QEP and are based on the operating expense reports of QEP and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. Certain gathering and transportation costs as well as NGL processing fees are included in the operating costs. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by QEP. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by QEP and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by QEP were accepted without independent verification.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with QEP's plans to develop these reserves as of December 31, 2019. The implementation of QEP's development plans as presented to us and incorporated herein is subject to the approval process adopted by QEP's management. As the result of our inquiries during the course of preparing this report, QEP has informed us that the development activities included herein have been subjected to and received the internal approvals required by QEP's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to QEP. QEP has provided written documentation supportin g their commitment to proceed with the development activities as presented to us. Additionally, QEP has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2019, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by QEP were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and

maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to QEP. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by QEP.

QEP makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, QEP has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Forms S-3 and/or S-8 of QEP of the references to our name as well as to the references to our third party report for QEP, which appears in the December 31, 2019 annual report on Form 10-K of QEP. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by QEP.

We have provided QEP with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by QEP and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ Stephen E. Gardner

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President
[Seal]

SEC (FWZ)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is also a member of the Society of Petroleum Engineers and a former chairman for the Denver Chapter of the Society of Petroleum Evaluation Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2019 continuing education hours, Mr. Gardner attended the annual Ryder Scott Reserves Conference in Houston, Texas which covered a variety of reserves topics including data analytics, unconventional resource issues, SEC comment letter trends, and others. In addition, Mr. Gardner attended the 2019 SPEE conference held at Lake Louise, Alberta, Canada, various local SPEE technical seminars, URTeC, and other internal company training courses throughout the year covering topics such as analysis techniques for unconventional reservoirs, ethics, regulatory issues, reserves evaluation, and more.

Based on his educational background, professional training and more than 14 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.