QEP RESOURCES®

Fellow Shareholders:

Our accomplishments in 2017 were significant, including the divestiture of our Pinedale Anticline natural gas asset and expansion of our tier-one acreage position in the Permian Basin. We continued to accelerate our development activity while actively enhancing our drilling and completion designs in the Permian Basin. We also had success with our refrac programs in both the Haynesville and the Williston Basin and we successfully completed our first long-lateral horizontal well utilizing state-of-the-art completion techniques in the Haynesville.

In February 2018, our Board of Directors approved several strategic and financial initiatives to transition QEP to a pure-play Permian Basin company and to address the significant discount to net asset value reflected in the Company's share price.

2018 Strategic and Financial Initiatives

Strategic Initiatives

- Engagement of financial advisors to assist with the divestiture of the Company's Williston and Uinta basin assets
- Marketing of remaining non-Permian assets, including the Haynesville/Cotton Valley

Financial Initiatives

- Use of proceeds from asset sales, to fund Permian Basin development program (until the program reaches operating cash flow neutrality in 2019), reduce debt and return cash to shareholders through share repurchases
- Authorized a $1.25 billion share repurchase program[1]
- Approval of a 2018 capital investment plan of approximately $1.075 billion, of which approximately 65 percent will be directed toward the Permian Basin.

These initiatives are responsive to ongoing shareholder feedback and fit with our long-term goal of becoming a more oil-focused company. At year-end 2017, our Permian Basin assets consist of approximately 44,000 net acres in the core of the northern Midland Basin. In 2017, these assets delivered 6.1 million barrels of net oil production and 8.2 million barrels of oil equivalent production and we reported estimated year-end total proved reserves of 272.7 million barrels of oil equivalent.

As we embark on these ambitious strategic and financial initiatives, I am confident they will allow us to simplify our portfolio, streamline our operations, and sharpen our focus on our Permian Basin assets – quickly resulting in QEP becoming a leading pure-play Permian company and ultimately delivering significant long-term value to you, our shareholders.

2017 Year-In-Review

In 2017, we continued to make great progress in becoming a more crude oil-focused company. We reported record year-end proved crude oil reserves of 320.5 million barrels. We also made progress simplifying and streamlining our asset portfolio with the divestiture of our Pinedale Anticline natural gas asset in Wyoming for $718 million and the sale of other gas properties in southwest Wyoming.

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[1] Subject to available liquidity, market conditions and proceeds from asset sales

We used the proceeds from the sale of our Pinedale asset to continue to expand our tier-one position in the Permian Basin by acquiring approximately 15,100 net acres of crude oil properties in the core of the northern Midland Basin. The acquisition of this high-quality acreage, which is adjacent and contiguous to our other Permian properties, will considerably enhance our ability to increase our crude oil production, improve our operating efficiencies and leverage our solid operational execution.

In the Haynesville Shale, we continued our successful "refrac" program during the year. Since our refrac program began in the second-quarter 2016, gross gas production in the Haynesville has increased by nearly 248 million cubic feet equivalent per day without the addition of a drilling rig. In September, we added a drilling rig in the Haynesville and commenced drilling new wells for the first time since 2012. Two of these new wells were completed in late 2017 utilizing state-of-the-art completion techniques, with our first 10,000 foot horizontal well testing over 40 million cubic feet of natural gas per day. We're extremely pleased with our refrac program and newly drilled well results and look forward to continuing both programs in 2018.

In the Williston Basin, we continued our successful drilling program and also began a refrac program using a design which was closely patterned after the successful methodology that we utilized in our Haynesville wells. While we're still fine-tuning our refrac design, we're very encouraged by the early results, and we look forward to continuing the program in 2018.

We are convinced that by executing the strategic and financial initiatives approved by our Board of Directors, and building upon the success we achieved in 2017, we can unlock significant value for our shareholders while creating a highly competitive pure-play Permian Basin oil company for the future.

Thank you for investing in QEP.

Sincerely,

Charles B. Stanley
Chairman, President & Chief Executive Officer

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, 2017

001-34778
(Commission File No.)

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

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

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

Title of each class	Name of each exchange on which registered
Common stock, $0.01 par value	**New York Stock Exchange**

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☒ 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 and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted 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 and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. 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	☐	(Do not check if a smaller reporting company)	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, 2017): $2,429,606,369.

At January 31, 2018, there were 240,968,931 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 2018 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). These reports and other information can be read and copied at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549-0213. Please call the SEC at 800-732-0330 for further information on the operation of the Public Reference Room. The SEC also 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 contains copies of charters for various board committees, including the Audit Committee, Corporate Governance Guidelines and QEP's Code of Conduct.

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 to transition to a pure-play Permian Basin company;
- plans to grow oil and gas production;
- impact on production from disruptions in transportation and midstream services;
- drilling and completion plans and strategies;
- refracturing of wells in the Haynesville/Cotton Valley and the Williston Basin;
- adding additional acreage in the Permian Basin;
- estimated reserves and development of such reserves;
- managing counterparty risk exposure;
- 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 for same;
- factors affecting our decision to modify our development plans;
- impact of weather on drilling, completion and production operations;
- our ability to meet delivery and sales commitments;
- impact of and compliance with government regulations;
- FERC regulation of oil and gas pipelines;
- impact of tax reform legislation on our tax position;
- adequacy of insurance;
- volatility of oil, gas and NGL prices and factors impacting such prices;
- delays caused by transportation, processing, storage and refining capacity issues;
- impact of shutting in wells;
- factors impacting our ability to transport oil 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 and capital expenditures to address air emission noncompliance issues;
- the underfunded status of our pension plan;
- impact of our charter and bylaws on a potential takeover;
- the usefulness of Adjusted EBITDA (a non-GAAP financial measure) and adjustments made to net income to arrive at Adjusted EBITDA;
- our inventory of drilling locations;
- aggregate purchase price for acquisitions of additional oil and gas interests in the Permian Basin pursuant to offers made in the fourth quarter of 2017;
- evaluation of potential acquisitions, divestitures and joint venture opportunities;
- plans to market its assets in the Williston Basin, the Uinta Basin and Haynesville/Cotton Valley to simplify our asset portfolio;
- growing oil and NGL production and transitioning to a more balanced portfolio;
- our balance sheet and sufficient liquidity providing for the ability to grow oil production;
- adjustments to our capital investment program based on a variety of factors, including an evaluation of drilling and completion activities and drilling results;
- focus on operating costs and per well drilling costs;
- amount and allocation of forecasted capital expenditures (excluding property acquisitions) and, plans for funding operations and capital investments;
- impact of lower or higher commodity prices and interest rates;
- focus on a sufficient liquidity position to ensure financial flexibility;
- potential for asset impairments and factors impacting impairment amounts;
- plans to recover or reject ethane from produced natural gas;
- 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;
- estimated amount of potential impairment of proved and unproved property, primarily in the Williston Basin;
- 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;
- oil exports from and imports to the U.S.;
- mitigation of losses related to unutilized capacity under transportation commitments and storage activities;
- inflation and deflation;
- sufficiency of our liquidity position to ensure financial flexibility and fund our operations and capital expenditures;
- estimates of the amount of additional indebtedness we may incur under our revolving credit facility;
- factors adversely impacting our liquidity;
- 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;
- loss contingencies;
- factors impacting bad debt expense;
- unrecognized tax benefits and the realization of those benefits;
- implementation and impact of new accounting pronouncements;
- pro forma results for acquired properties;
- estimates of future liability for deficiency charges in connection with the divestiture of our assets in Pinedale (the Pinedale Divestiture);

- assumptions regarding share-based compensation;
- settlement of performance share units and restricted share units in cash;
- employee benefit plan gains or losses;
- recognition of compensation costs related to share-based compensation grants;
- impact of tax regulatory guidance on financial statements;
- realization of alternative minimum tax credits; and
- estimated general and administrative expenses related to our retention and severance program.

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, natural resources, fish and wildlife, hydraulic fracturing, water use and drilling and completion techniques, as well as the risk of legal proceedings arising from such matters, whether involving public or private claimants or regulatory investigative or enforcement measures;
- derivative activities;
- potential losses or earnings reductions from our commodity price risk management programs;
- volatility in the commodity-futures market;
- failure of internal controls and procedures;
- failure of our information technology infrastructure or applications to prevent a cyberattack;
- elimination of federal income tax deductions for oil and gas exploration and development costs;
- production, severance and property taxation rates;
- discount rates;
- regulatory approvals and compliance with contractual obligations;
- actions of, or inaction by federal, state, local or tribal governments, foreign countries and the Organization of Petroleum Exporting Countries;
- lack of, or disruptions in, adequate and reliable transportation for our production;
- competitive conditions;
- production and sales volumes;
- actions of operators on properties in which we own an interest but do not operate;
- estimates of oil and gas reserve quantities;
- reservoir performance;
- operating costs;
- inflation;
- capital costs;

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

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

Glossary of Terms

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

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

B Billion.

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

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

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

Boe Barrels of oil equivalent.

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

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

cfe Cubic foot or feet of natural gas equivalents.

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

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

exploratory well A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

FERC The Federal Energy Regulatory Commission.

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

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

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

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

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

M Thousand.

MM Million.

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

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

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

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

net "Net" oil and gas wells or "net" acres are the sum of the fractional working interest the Company owns in the gross wells or acres. "Net" revenues are QEP Resources Inc.'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.

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

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

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

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

proved properties Properties with proved reserves.

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

proved undeveloped reserves or PUD reserves Proved undeveloped reserves or PUD reserves are those reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

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

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

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

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

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

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

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

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

FORM 10-K
ANNUAL REPORT 2017
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 Northern Region (primarily in North Dakota and Utah) and the Southern Region (primarily in Texas and Louisiana). 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".

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

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

Effective January 1, 2016, QEP terminated its contracts for resale and marketing transactions between its wholly owned subsidiaries, QEP Marketing Company (QEP Marketing) and QEP Energy Company (QEP Energy). In addition, substantially all of QEP Marketing's third-party purchase and sale agreements and gathering, processing and transportation contracts were assigned to QEP Energy, except those contracts related to natural gas storage activities and Haynesville Gathering. As a result, QEP Energy directly markets its own oil, gas and NGL production. While QEP continues to act as an agent for the sale of oil, 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, 2017, QEP:

- Generated net income of $269.3 million, or $1.12 per diluted share;
- Reported $736.1 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 17% increase over 2016;
- Recognized realized oil prices that were $6.07 per bbl, or 14% higher compared to 2016;
- Divested assets in Pinedale for approximately $718.2 million;
- Delivered oil equivalent production of 53.1 MMboe, a 5% decrease from 2016;
- Delivered record oil production of 6.1 MMbbls in the Permian Basin, a 52% increase over 2016;
- Reported year end total proved reserves of 684.7 MMboe, including record proved crude oil reserves of 320.5 MMbbl;
- Incurred capital expenditures (excluding property acquisitions) of $1,219.8 million, a 130% increase over 2016;
- Acquired various oil and gas properties for approximately $815.2 million, of which the vast majority were properties in the Permian Basin;
- Expanded our successful refracturing program in Haynesville/Cotton Valley and began refracturing wells in the Williston Basin; and
- Issued $500.0 million of senior notes and repaid $445.7 million of senior notes, which were due in 2018, 2020 and 2021; paid fees and expenses associated with the repayment and used the remainder for general corporate purposes.

Strategies

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

- operate in a safe and environmentally responsible manner;
- simplify our asset portfolio and focus on our Permian Basin assets;
- maintain an inventory of high return development projects in the Permian Basin;
- allocate capital to those projects that generate the highest returns;
- increase oil 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

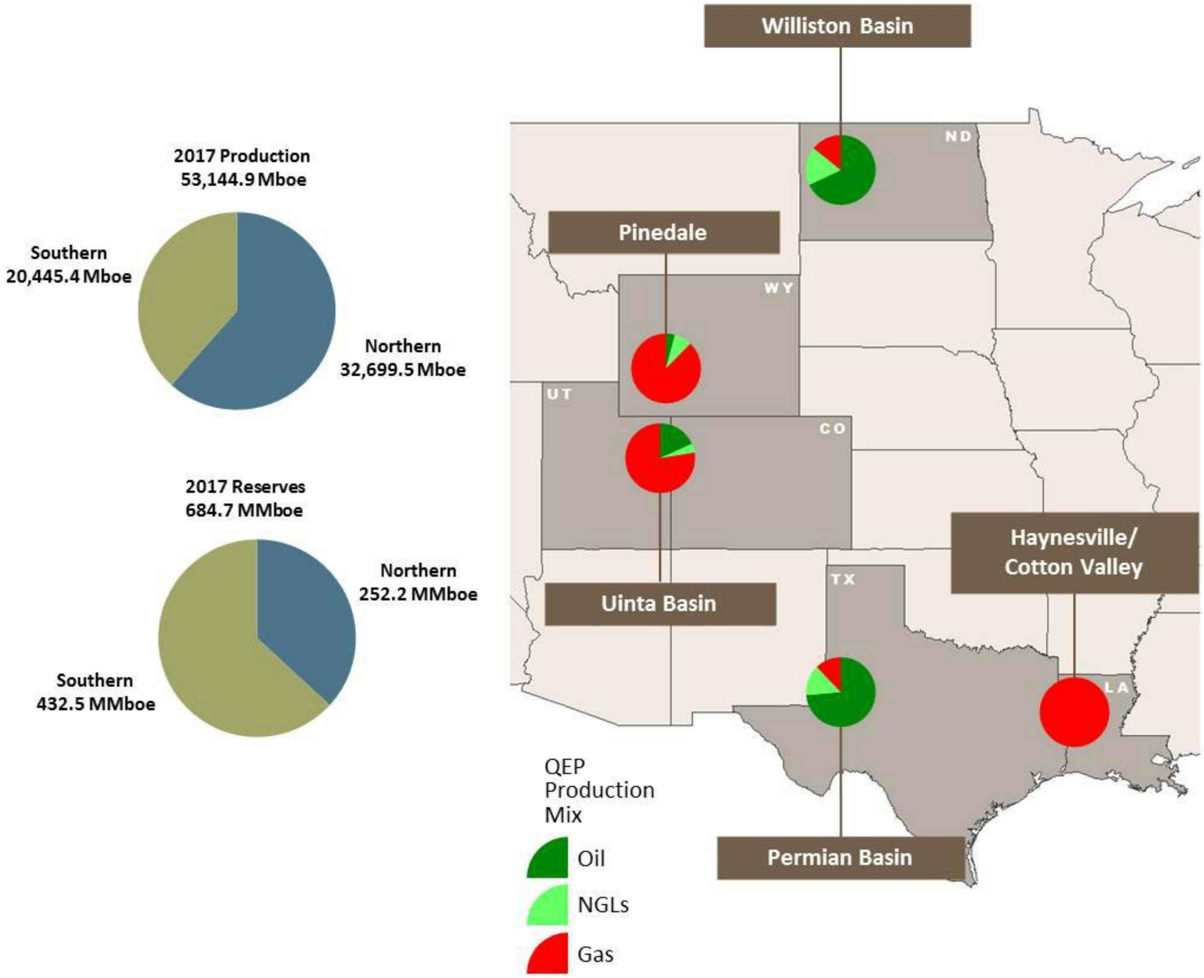
QEP conducts exploration and production (E&P) activities in several of North America's most important hydrocarbon resource plays. QEP has an inventory of developed and identified undeveloped drilling locations in the Permian Basin in western Texas, the Williston Basin in North Dakota, Haynesville/Cotton Valley in northwestern Louisiana, the Uinta Basin in eastern Utah and other proven properties in Wyoming, Utah and Colorado.

While historically the Company has been more natural gas-weighted, in recent years the Company has increased its focus on growing its oil and NGL production. Since the beginning of 2012, the Company has made approximately $3.9 billion of acquisitions of oil-weighted properties, spent approximately 60% of its capital expenditures (excluding property acquisitions) on its oil-weighted properties, and divested gas-weighted properties, such as Pinedale. Compared to 2011, the Company's 2017 oil production has grown 424% and the Company's 2017 oil and NGL production represented 47% of total production compared to 14% in 2011. Additionally, oil and NGL revenue represented 68% of total field-level revenues during 2017 compared to 27% in 2011. Approximately 56% of total proved reserves at year-end 2017 were oil and NGL. Consistent with its emphasis on oil-weighted properties, QEP now reflects its production and reserve amounts in oil equivalent volumes rather than gas equivalent volumes. In February 2018, QEP's Board of Directors has unanimously approved several strategic initiatives including plans to market its assets in the Williston Basin, the Uinta Basin and Haynesville/Cotton Valley and focus its activities in the Permian Basin.

In the fourth quarter of 2017, QEP closed on the acquisition of oil and gas properties in the Permian Basin (the 2017 Permian Basin Acquisition) for an aggregate purchase price of $720.7 million, subject to post-closing purchase price adjustments. The 2017 Permian Basin Acquisition consists of approximately 15,100 acres, mainly in Martin County, Texas, which are held by production from existing vertical wells. In addition, QEP has made offers to various persons who own additional oil and gas interests in certain properties included in the 2017 Permian Basin Acquisition on substantially the same terms and conditions as the purchase. If all offers are accepted, QEP now expects that the aggregate purchase price will not exceed $50.0 million. In February 2018, QEP entered into agreements related to these offers for an aggregate purchase price of $36.1 million, subject to customary purchase price adjustments. The transactions and remaining offers, if accepted, are expected to be funded with borrowings under the credit facility and are expected to close in the first half of 2018. QEP received aggregate proceeds of $806.8 million related to the sales of our Pinedale assets (the Pinedale Divestiture) and other properties during the year ended December 31, 2017. All of the proceeds from the Pinedale Divestiture were used to close the 2017 Permian Basin Acquisition.

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

In addition, the following map illustrates the location of the Company's significant E&P activities, the location of its Northern and Southern Regions, and related reserve and production data during December 31, 2017:



QEP sells gas volumes to wholesale marketers, industrial users, local distribution companies, midstream service providers and utility companies. QEP sells oil and NGL volumes to refiners, marketers, midstream service providers and other companies, including some with pipeline facilities near QEP's producing properties. QEP 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, gas and NGL volumes to their ultimate sale point, QEP has contracts with midstream providers for the gathering, transportation, processing and/or fractionation of these products. In addition, QEP has firm transportation commitments with interstate pipelines to move its gas volumes to multiple destinations dependent upon market conditions. Disruptions impacting pipelines or other midstream providers' facilities can impact QEP's production volumes. In cases where QEP's wells are not connected to sales pipelines, the Company sells its products to buyers at the well and the buyer arranges transportation to the ultimate destination.

Description of Properties

Northern Region

Williston Basin
QEP has 362.0 net productive wells (including its interest in non-operated wells) in the Williston Basin that generate substantial cash flows, which help fund future development of the Company's portfolio of assets. QEP has developed a majority of its acreage but continues its drilling program targeting the Bakken and Three Forks formations. In addition, QEP initiated a refracturing program in the Williston Basin. As of December 31, 2017, QEP had one operated rig drilling in the Williston Basin.

Pinedale
In September 2017, QEP divested of its Pinedale assets for net cash proceeds (after purchase price adjustments) of $718.2 million, subject to post-closing purchase price adjustments, and recorded a pre-tax gain on sale of $180.4 million, which was recorded within "Net gain (loss) from asset sales" on the Consolidated Statements of Operations.

Uinta Basin
The majority of the Uinta Basin's proved reserves are found in a series of vertically stacked, laterally discontinuous reservoirs. In 2017, QEP changed from a vertical well development plan to a horizontal well development plan and has a large inventory of remaining future locations. As of December 31, 2017, QEP had one operated rig drilling in the Uinta Basin.

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

Southern Region

Permian Basin
QEP has 590.2 net productive wells in the Permian Basin. QEP has multiple targeted formations within its acreage in the Permian Basin and is actively developing oil producing zones, primarily in the Spraberry Shale and Wolfcamp formations. QEP continues to actively acquire acreage in the basin and in 2017, acquired approximately 17,000 additional net acres. QEP is utilizing a "tank-style" completion methodology and continues to test additional formations and evaluate the appropriate ultimate density of its development program. As of December 31, 2017, QEP had six operated rigs drilling in the Permian Basin.

Haynesville/Cotton Valley
QEP owns producing and undeveloped properties in Haynesville/Cotton Valley and additional lease rights that cover the overlying Hosston and Cotton Valley formations. QEP has 507.0 net productive wells, including its interest in non-operated wells, in Haynesville/Cotton Valley. Production is primarily dry gas and QEP has numerous future locations to fully develop its acreage. In addition, the Company began a refracturing program in 2016 and continued throughout 2017 and into 2018 on QEP operated wells. As of December 31, 2017, QEP had one operated rig drilling in Haynesville/Cotton Valley.

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

Reserves

At December 31, 2017 and 2016, QEP's estimated proved reserves were approximately 684.7 MMboe and 731.4 MMboe, respectively, of which 98% and 97%, respectively, were Company operated. Proved developed reserves represented 37% and 49% of the Company's total proved reserves at December 31, 2017 and 2016, 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, 2017				December 31, 2016			
	Oil (MMbbl)	**Gas[(1)] (Bcf)**	**NGL (MMbbl)**	**Total[(1)] (MMboe)[(2)]**	Oil (MMbbl)	Gas[(1)] (Bcf)	NGL (MMbbl)	Total[(1)] (MMboe)[(2)]
Proved developed reserves	**116.0**	**655.5**	**27.9**	**253.1**	103.2	1,309.8	35.7	357.2
Proved undeveloped reserves	**204.5**	**1,138.1**	**37.3**	**431.6**	135.4	1,244.0	31.5	374.2
Total proved reserves	**320.5**	**1,793.6**	**65.2**	**684.7**	238.6	2,553.8	67.2	731.4

(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, 2015, through December 31, 2017, are summarized in the table below:

Year Ended December 31,	Year End Reserves (MMboe)	Oil, Gas and NGL Production (MMboe)	Reserve Life Index[(1)(2)] (Years)
2015	603.4	54.5	11.1
2016	731.4	55.8	13.1
2017	**684.7**	**53.1**	**12.9**

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

(2) The reserve life index for 2017 includes 9.9 MMboe of production volumes from Pinedale but no year-end reserves as a result of the Pinedale Divestiture in September 2017. Excluding production volumes from the divested Pinedale assets, the reserve life index is 15.8 years for the year ended December 31, 2017.

Proved Reserves

Proved reserve estimates and related information is presented consistent with the requirements of the SEC's rules for the Modernization of Oil and Gas Reporting. These rules permit the use of reliable technologies to estimate and categorize reserves and require the use of the 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 14 – Supplemental Oil and Gas Information (unaudited), in Item 8 of Part II of this Annual Report on Form 10-K for additional 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,			
	2017		2016	
Northern Region	(MMboe)	(% of total)	(MMboe)	(% of total)
Williston Basin	**146.9**	**21%**	160.2	22%
Pinedale	**—**	**—%**	160.7	22%
Uinta Basin	**100.8**	**15%**	106.1	14%
Other Northern	**4.5**	**1%**	12.3	2%
Southern Region				
Permian Basin	**272.7**	**40%**	147.8	20%
Haynesville/Cotton Valley	**159.8**	**23%**	144.3	20%
Other Southern	**—**	**—%**	—	—%
Total proved reserves	**684.7**	**100%**	731.4	100%

QEP's total proved reserves as of December 31, 2017, decreased 46.7 MMboe from December 31, 2016, primarily due to the Pinedale Divestiture, which was partially offset by an increase of proved reserves as a result of extensions and discoveries in the Permian Basin and the acquisition of reserves from the 2017 Permian Basin Acquisition. Williston Basin proved reserves decreased primarily from under performance of wells in our high density pilot test areas. Other Northern proved reserves decreased primarily due to property divestitures in 2017. Uinta Basin proved reserves decreased primarily due to changing from a vertical well development plan to a horizontal well development plan. Haynesville/Cotton Valley's increase of proved reserves is primarily the result of the successful refracturing program in 2017.

Proved Undeveloped Reserves

Significant changes to PUD reserves that occurred during 2017 are summarized in the table below:

	2017
	(MMboe)
Proved undeveloped reserves at January 1,	374.2
Transferred to proved developed reserves	**(36.5)**
Revisions to previous estimates	**(26.3)**
Extensions and discoveries	**71.8**
Purchase of reserves in place	**71.9**
Sale of reserves in place	**(23.5)**
Proved undeveloped reserves at December 31,	**431.6**

Transfers to proved developed reserves. The costs incurred for the development of PUD reserves were approximately $389.3 million, $258.1 million and $490.4 million for the years ended December 31, 2017, 2016 and 2015, respectively. Costs incurred for the development of PUD reserves increased in 2017 from 2016, however the amount of reserves converted decreased because 16.4 MMboe of PUD reserves were converted in 2016 as a result of installation of additional centralized compression in Pinedale which did not have any associated development costs.

QEP's planned and actual transfers of proved undeveloped reserves to proved developed reserves results for the year ended December 31, 2017 are summarized in the table below:

	Planned Transfers to Proved Developed Reserves in 2017 as of December 31, 2016 (PUD conversions)	Actual Transfers to Proved Developed Reserves in 2017 (PUD conversions)	Difference
		(MMboe)	
Northern Region			
Williston Basin	10.6	16.3	5.7
Pinedale	3.2	6.2	3.0
Uinta Basin	—	—	—
Other Northern	—	—	—
Southern Region			
Permian Basin	25.1	16.7	(8.4)
Haynesville/Cotton Valley	6.5	3.5	(3.0)
Other Southern	—	—	—
Total	45.4	42.7	(2.7)
Pinedale[1]	(3.2)	(6.2)	(3.0)
Total excluding Pinedale	42.2	36.5	(5.7)

[1] Pinedale PUD reserve conversions in 2017 include actual activity through the closing date of the Pinedale Divestiture.

QEP transferred 36.5 MMboe of PUD reserves to proved developed reserves in 2017 compared to 45.4 MMboe that were planned for 2017. QEP's PUD reserves conversion rate (the percentage of booked PUD reserves) was 10%, 18% and 23% for the years ended December 31, 2017, 2016 and 2015, respectively. At December 31, 2016, QEP's planned PUD reserve conversion rate for 2017 was 12.1%. QEP converted fewer PUD reserves than expected primarily due to unforeseen drilling delays in the Permian Basin as we continued to refine our "tank-style" development and changes in estimated well spacing, which led to drilling more unproved locations than initially planned. In both Haynesville/Cotton Valley and Pinedale, we had property divestitures that had PUD conversions in 2017, but because these properties were no longer owned at December 31, 2017, these PUD conversions are not part of our year end 2017 conversions to proved developed reserves. In addition, the PUD reserve conversions in Haynesville/Cotton Valley were lower than planned conversions due to the delayed arrival of the drilling rig in 2017. These lower than planned PUD conversions were partially offset by a higher PUD conversion rate in the Williston Basin as we shifted more development to PUD locations from the unproved locations that were initially planned.

All of QEP's proved undeveloped reserves at December 31, 2017, are scheduled to be developed within five years from the date such locations were initially disclosed as proved undeveloped reserves. QEP removes reserves associated with a PUD location from reported proved reserves if such location is scheduled, under the then-current development plan, to be drilled later than five years from the date that such location was first reported as PUD. QEP's five-year development plan generally does not contemplate a uniform (i.e. 20% per year) conversion of PUD reserves in all of its producing regions, and PUD reserve conversion rates will likely differ by producing region.

At December 31, 2017, QEP estimates that its future development costs relating to the development of PUD reserves are approximately $486.5 million in 2018, $710.0 million in 2019, and $1,006.2 million in 2020. Estimated future development costs include capital spending on major development projects, some of which will take several years to complete. QEP believes cash flow from operations and availability under its revolving credit facility will be sufficient to cover these estimated future development costs. In addition, QEP estimates that its future development costs relating to wells waiting on completion and its refracturing program, which are not classified as PUD, are approximately $132.6 million in 2018.

Revisions to previous estimates. Revisions to previous estimates reflect our ongoing evaluation of our asset portfolio. In 2017, our PUD reserves decreased by 26.3 MMboe due to the positive and negative factors summarized in the table below:

	2017
	(MMboe)
Revisions due to:	
Changes in year-end prices (price impact to January 1, 2017 balance)	**7.8**
Positive performance	**17.7**
Change in development plans	**(39.5)**
Removal due to five year SEC rule	**(8.7)**
Other	**(3.6)**
Total revisions to prior estimates	**(26.3)**

In 2017, PUD reserves were revised downward by 26.3 MMboe primarily due to negative revisions from changes in development plans (39.5 MMboe) primarily as a result of changing from a vertical well development plan to a horizontal development plan in the Uinta Basin and increased number of longer laterals in Haynesville/Cotton Valley. These negative revisions related to changes in development plans are partially offset by positive revisions related to additional increased density locations in the Haynesville/Cotton Valley and the Williston Basin. The 17.7 MMboe positive performance revision is primarily from Haynesville/Cotton Valley's successful refracturing program. In addition, QEP removed 8.7 MMboe of PUD reserves that were no longer in our 2018 forecasted capital expenditure plan and will not be drilled and completed within five years of the initial date of booking of the reserves.

Extensions and Discoveries. Extensions and discoveries in 2017 were primarily in the Permian Basin and related to new well completions and associated new PUD locations.

Purchase of Reserves in Place. Purchase of reserves in place in 2017 was primarily related to the 2017 Permian Basin Acquisition and various other acquired oil and gas properties as discussed in Note 2 – 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 2017 was primarily related to the Pinedale Divestiture as discussed in Note 2 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K.

Additional Disclosures
Refer to Note 14 – Supplemental Oil and Gas Information (unaudited) in Item 8 of Part II of this Annual Report on Form 10-K for additional 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, 2017, 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, 2017 and 2016, and retained RSC and DeGolyer and MacNaughton (D&M) to prepare the estimates of all of its proved reserves as of December 31, 2015. RSC prepared approximately 90% and D&M prepared approximately 10% of the Company's total net proved reserves as of December 31, 2015.

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, 2017, is a registered Professional Engineer in the State of Colorado and graduated with a Master's of Science degree in Geological Engineering from the University of Missouri at Rolla in 1976. The individual has over 30 years of experience in the petroleum industry, including experience estimating and evaluating petroleum reserves. A more detailed letter, including such individual's professional qualifications, has been filed as part of Exhibit 99.1 to this report.

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

Technologies Used
To estimate proved reserves, the SEC allows a company to use technologies that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. A variety of methodologies were used to determine QEP's proved reserve estimates. The principal methodologies employed are performance, analogy and volumetric methods.

All of the proved producing reserves 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 2017, 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.

In 2017, all of QEP's proved developed non-producing and undeveloped reserves included in this Annual Report on Form 10-K 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 well density; current commodity pricing and cost forecasts consistent with SEC guidelines; recent drilling and re-stimulated well results; availability of services, equipment, supplies and personnel; seasonal weather; and changes in drilling and completion techniques and technology. This process is intended to ensure that PUD reserves are only claimed for locations where a final investment decision has been made by the Company.

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

Management reviews and revises the development plan throughout the year and may modify the development plan after evaluating a number of factors, including operating and drilling results; current and expected future commodity prices; estimated risk-based returns; estimated well density; advances in technology; cost and availability of services, equipment, supplies and personnel; acquisition and divestiture activity; and our current and projected financial condition and liquidity. Management reviews changes to the development plan with the Audit Committee and the Board quarterly. Changes in the development plan are also considered by management, the Director of Corporate Reserves and the Reserves Review Committee when reserves are estimated at year-end. If there are changes that 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, gas and NGL produced, and the related production costs, for the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	2016	2015
Production volumes			
Oil (Mbbl)	**19,620.7**	20,293.8	19,582.3
Gas (Bcf)	**168.9**	177.0	181.1
NGL (Mbbl)	**5,367.3**	5,978.8	4,704.3
Total equivalent production (Mboe)	**53,144.9**	55,780.2	54,462.1
Total equivalent production (Bcfe)	**318.9**	334.7	326.8
Average field-level price [(1)]			
Oil (per bbl)	**$ 47.88**	$ 37.90	$ 42.59
Gas (per Mcf)	**$ 2.92**	$ 2.36	$ 2.59
NGL (per bbl)	**$ 20.85**	$ 13.97	$ 16.98
Production costs (per Boe)			
Lease operating expense	**$ 5.55**	$ 4.03	$ 4.38
Transportation and processing costs	**4.61**	5.18	5.35
Production and property taxes	**2.15**	1.70	2.16
Total production costs	**$ 12.31**	$ 10.91	$ 11.89

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

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

	Year Ended December 31,			Change	
	2017	2016	2015	**2017 vs 2016**	2016 vs 2015
Oil production volumes (Mbbl)					
Northern Region					
Williston Basin	**12,353.5**	14,658.6	14,871.8	**(2,305.1)**	(213.2)
Pinedale	**403.8**	670.9	716.6	**(267.1)**	(45.7)
Uinta Basin	**656.8**	774.2	848.6	**(117.4)**	(74.4)
Other Northern	**114.2**	141.9	186.5	**(27.7)**	(44.6)
Southern Region					
Permian Basin	**6,060.9**	3,983.9	2,791.2	**2,077.0**	1,192.7
Haynesville/Cotton Valley	**26.5**	28.4	33.6	**(1.9)**	(5.2)
Other Southern	**5.0**	35.9	134.0	**(30.9)**	(98.1)
Total production	**19,620.7**	20,293.8	19,582.3	**(673.1)**	711.5

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

	Year Ended December 31,			Change	
	2017	2016	2015	**2017 vs 2016**	2016 vs 2015
Gas production volumes (Bcf)					
Northern Region					
Williston Basin	**15.5**	15.2	11.3	**0.3**	3.9
Pinedale	**51.9**	82.4	87.5	**(30.5)**	(5.1)
Uinta Basin	**16.8**	22.4	22.7	**(5.6)**	(0.3)
Other Northern	**5.7**	7.9	9.4	**(2.2)**	(1.5)
Southern Region					
Permian Basin	**6.0**	5.3	4.4	**0.7**	0.9
Haynesville/Cotton Valley	**72.9**	43.4	43.2	**29.5**	0.2
Other Southern	**0.1**	0.4	2.6	**(0.3)**	(2.2)
Total production	**168.9**	177.0	181.1	**(8.1)**	(4.1)

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

	Year Ended December 31,			Change	
	2017	2016	2015	**2017 vs 2016**	2016 vs 2015
NGL production volumes (Mbbl)					
Northern Region					
Williston Basin	**3,206.1**	3,182.7	1,953.4	**23.4**	1,229.3
Pinedale	**811.0**	1,417.1	1,528.6	**(606.1)**	(111.5)
Uinta Basin	**152.0**	203.9	287.6	**(51.9)**	(83.7)
Other Northern	**13.4**	22.3	19.6	**(8.9)**	2.7
Southern Region					
Permian Basin	**1,168.5**	1,109.9	815.4	**58.6**	294.5
Haynesville/Cotton Valley	**16.2**	28.2	28.6	**(12.0)**	(0.4)
Other Southern	**0.1**	14.7	71.1	**(14.6)**	(56.4)
Total production	**5,367.3**	5,978.8	4,704.3	**(611.5)**	1,274.5

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

	Year Ended December 31,			Change	
	2017	2016	2015	**2017 vs 2016**	2016 vs 2015
Total production volumes (Mboe)					
Northern Region					
Williston Basin	**18,140.0**	20,370.0	18,709.6	**(2,230.0)**	1,660.4
Pinedale	**9,871.7**	15,826.0	16,829.6	**(5,954.3)**	(1,003.6)
Uinta Basin	**3,605.4**	4,714.3	4,924.0	**(1,108.9)**	(209.7)
Other Northern	**1,082.4**	1,491.7	1,764.1	**(409.3)**	(272.4)
Southern Region					
Permian Basin	**8,227.2**	5,976.7	4,332.5	**2,250.5**	1,644.2
Haynesville/Cotton Valley	**12,188.7**	7,285.5	7,268.0	**4,903.2**	17.5
Other Southern	**29.5**	116.0	634.3	**(86.5)**	(518.3)
Total production	**53,144.9**	55,780.2	54,462.1	**(2,635.3)**	1,318.1

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

	Year Ended December 31,			Change	
	2017	2016	2015	**2017 vs 2016**	2016 vs 2015
Average field-level oil price (per bbl)					
Northern Region	**$ 47.24**	$ 36.97	$ 41.78	**$ 10.27**	$ (4.81)
Southern Region	**$ 49.30**	$ 41.68	$ 47.16	**$ 7.62**	$ (5.48)
Average field-level oil price	**$ 47.88**	$ 37.90	$ 42.59	**$ 9.98**	$ (4.69)
Average field-level gas price (per Mcf)					
Northern Region	**$ 2.93**	$ 2.33	$ 2.58	**$ 0.60**	$ (0.25)
Southern Region	**$ 2.92**	$ 2.42	$ 2.60	**$ 0.50**	$ (0.18)
Average field-level gas price	**$ 2.92**	$ 2.36	$ 2.59	**$ 0.56**	$ (0.23)
Average field-level NGL price (per bbl)					
Northern Region	**$ 21.41**	$ 14.50	$ 18.06	**$ 6.91**	$ (3.56)
Southern Region	**$ 18.87**	$ 11.75	$ 12.49	**$ 7.12**	$ (0.74)
Average field-level NGL price	**$ 20.85**	$ 13.97	$ 16.98	**$ 6.88**	$ (3.01)
Lease operating and transportation and processing costs (per Boe)					
Northern Region	**$ 11.24**	$ 8.71	$ 8.67	**$ 2.53**	$ 0.04
Southern Region	**$ 9.52**	$ 10.79	$ 13.41	**$ (1.27)**	$ (2.62)
Average lease operating and transportation and processing costs	**$ 10.16**	$ 9.21	$ 9.73	**$ 0.95**	$ (0.52)

Northern Region

Williston Basin

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

Production volumes increased 9% to 20,370.0 Mboe during 2016 compared to 2015, due to increased gas and NGL production, which was primarily attributable to additional ethane recovered combined with higher gas recovery from a midstream provider in 2016. These increases were partially offset by a decrease in oil production volumes due to fewer net well completions in 2016 compared to 2015.

During the years ended December 31, 2017, 2016 and 2015, Williston Basin production represented 34%, 37% and 34%, respectively, of QEP's total equivalent production.

Pinedale

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

Production volumes decreased 6% to 15,826.0 Mboe during 2016 compared to 2015. Despite improved results from wells drilled and completed in 2016, production volumes decreased primarily as a result of fewer net well completions due to a decreased rig count in Pinedale in 2016 compared to 2015.

During the years ended December 31, 2017, 2016 and 2015, Pinedale production represented 19%, 28% and 31%, respectively, of QEP's total equivalent production.

Uinta Basin

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

Production volumes decreased 4% to 4,714.3 Mboe during 2016 compared to 2015, primarily due to decreased gas production from decreased net well completions in 2016 compared to 2015. QEP did not have an operated rig in the Uinta Basin for the majority of 2016.

During the years ended December 31, 2017, 2016 and 2015, Uinta Basin production represented 7%, 8% and 9%, respectively, of QEP's total equivalent production.

Other Northern

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

Production volumes decreased 15% to 1,491.7 Mboe during 2016 compared to 2015, primarily due to a decrease in gas production on Wyoming properties.

During the year ended December 31, 2017, Other Northern production represented 2% of QEP's total equivalent production, compared to 3% for the years ended December 31, 2016 and 2015, respectively.

Southern Region

Permian Basin

Production volumes increased 38% to 8,227.2 Mboe during 2017 compared to 2016, primarily as a result of continued horizontal development activities in the Spraberry Shale and Wolfcamp formations. QEP began 2017 with three operated drilling rigs in the Permian Basin and ended 2017 with six operated drilling rigs.

Production volumes increased 38% to 5,976.7 Mboe during 2016 compared to 2015, primarily due to continued horizontal development drilling, primarily in the Spraberry Shale, despite fewer net well completions in 2016 compared to 2015.

During the years ended December 31, 2017, 2016 and 2015, Permian Basin production represented 15%, 11%, and 9% respectively, of QEP's total equivalent production.

Haynesville/Cotton Valley

Production volumes increased 67% to 12,188.7 Mboe during 2017 compared to 2016, due to a well refracturing program that began in 2016 and continued throughout 2017 combined with two new well completions in 2017, partially offset by natural production decline. A QEP-operated drilling rig arrived at the end of the third quarter 2017 and remained active through the end of 2017.

Production volumes slightly increased to 7,285.5 Mboe during 2016 compared to 2015, due to refracturing of wells and increased non-operated production, partially offset by a natural decline and the continued suspension of QEP's operated drilling program.

During the year ended December 31, 2017, Haynesville/Cotton Valley's production represented 23% of QEP's total equivalent production, compared to 13% for the years ended December 31, 2016 and 2015, respectively.

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

Production volumes decreased 82% to 116.0 Mboe during 2016 compared to 2015, due to the continued divestiture of properties.

During the year ended December 31, 2015, Other Southern production represented 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, 2017, all of which are located in the U.S.:

	Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Northern Region						
Williston Basin	893	362.0	—	—	893	362.0
Pinedale[(1)]	—	—	—	—	—	—
Uinta Basin	1,557	210.3	763	567.0	2,320	777.3
Other Northern	29	13.4	109	58.9	138	72.3
Southern Region						
Permian Basin	626	590.2	—	—	626	590.2
Haynesville/Cotton Valley	1	0.1	857	506.9	858	507.0
Other Southern	1	—	58	4.0	59	4.0
Total productive wells	3,107	1,176.0	1,787	1,136.8	4,894	2,312.8

(1) As a result of the Pinedale Divestiture, QEP no longer owns operated or non-operated productive wells in Pinedale as of December 31, 2017 (Refer to Note 2 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K for more information).

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

The Company also holds numerous overriding royalty interests in oil and gas wells, a portion of which is convertible to working interests after recovery of certain costs by third parties. Once the overriding royalty interests are converted to working interests, these wells are included in the Company's gross and net well count.

Leasehold Acreage

The following table summarizes developed and undeveloped leasehold acreage in which the Company owns a working interest or mineral interest as of December 31, 2017. "Undeveloped Acreage" includes leasehold interests that already may 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 and other similar interests. All leasehold acres are located in the U.S.

	Developed Acres[1]		Undeveloped Acres[2]		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Colorado	168,348	113,540	75,549	17,129	243,897	130,669
Kansas	47,233	20,879	35,543	12,830	82,776	33,709
Louisiana	70,303	62,982	1,231	1,302	71,534	64,284
Montana	38,337	14,852	331,005	58,315	369,342	73,167
New Mexico	7,620	4,211	24,651	2,476	32,271	6,687
North Dakota	208,367	69,861	166,560	54,040	374,927	123,901
South Dakota	40	40	203,330	107,551	203,370	107,591
Texas	50,441	39,573	22,657	17,279	73,098	56,852
Utah	174,242	134,038	184,444	104,037	358,686	238,075
Wyoming	87,274	54,660	93,809	56,279	181,083	110,939
Other	15,435	4,207	157,822	43,517	173,257	47,724
Total	867,640	518,843	1,296,601	474,755	2,164,241	993,598

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

(2) Undeveloped acreage is leased acreage 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

A portion of the leases covering the acreage summarized in the preceding table will expire at the end of their respective primary terms unless the leases are renewed or drilling or production has occurred on the acreage subject to the lease prior to that date. Leases held by production 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,		
2018	13,867	12,024
2019	9,260	7,356
2020	7,868	7,228
2021	7,126	6,969
2022 and later	19,187	18,468
Total	57,308	52,045

Drilling Activity

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, 2017								
Northern Region								
Williston Basin	**55**	**28.2**	**—**	**—**	**—**	**—**	**—**	**—**
Pinedale	**20**	**8.6**	**—**	**—**	**—**	**—**	**—**	**—**
Uinta Basin	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Other Northern	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Southern Region								
Permian Basin	**65**	**65.0**	**—**	**—**	**1**	**0.7**	**—**	**—**
Haynesville/Cotton Valley	**14**	**2.8**	**—**	**—**	**—**	**—**	**—**	**—**
Other Southern	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Total	**154**	**104.6**	**—**	**—**	**1**	**0.7**	**—**	**—**
Year Ended December 31, 2016								
Northern Region								
Williston Basin	70	39.5	—	—	—	—	—	—
Pinedale	44	24.4	—	—	—	—	—	—
Uinta Basin	11	8.0	—	—	—	—	—	—
Other Northern	3	3.0	—	—	—	—	—	—
Southern Region								
Permian Basin	19	18.8	—	—	1	0.7	—	—
Haynesville/Cotton Valley	15	2.6	—	—	—	—	—	—
Other Southern	—	—	—	—	—	—	—	—
Total	162	96.3	—	—	1	0.7	—	—
Year Ended December 31, 2015								
Northern Region								
Williston Basin	154	59.7	—	—	—	—	—	—
Pinedale	107	68.1	—	—	—	—	—	—
Uinta Basin	30	11.2	—	—	—	—	—	—
Other Northern	3	3.0	—	—	1	1.0	—	—
Southern Region								
Permian Basin	38	32.5	—	—	—	—	—	—
Haynesville/Cotton Valley	24	3.2	—	—	—	—	—	—
Other Southern	4	0.1	—	—	—	—	—	—
Total	360	177.8	—	—	1	1.0	—	—

The following table presents operated and non-operated well completions for the year ended December 31, 2017:

	Operated Completions		Non-operated Completions	
	Gross	Net	Gross	Net
Northern Region				
Williston Basin	33	27.8	22	0.4
Pinedale	20	8.6	—	—
Uinta Basin	—	—	—	—
Other Northern	—	—	—	—
Southern Region				
Permian Basin	66	65.7	—	—
Haynesville/Cotton Valley	2	2.0	12	0.8
Other Southern	—	—	—	—

The following table presents operated and non-operated wells in the process of being drilled or waiting on completion as of December 31, 2017:

		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	1	2	2.0	5	4.7	—	—	7	0.1
Pinedale	—	—	—	—	—	—	—	—	—
Uinta Basin	1	1	1.0	1	1.0	—	—	—	—
Other Northern	—	—	—	—	—	—	—	—	—
Southern Region									
Permian Basin[(1)]	6	29	28.1	36	36.0	—	—	—	—
Haynesville/Cotton Valley	1	2	2.0	—	—	4	0.1	6	0.4
Other Southern	—	—	—	—	—	—	—	—	—

(1) The gross operated drilling well count in the Permian Basin includes 18 wells for which surface casing has been set, but as of December 31, 2017, did not have a rig drilling.

Each gross well completed in more than one producing zone is counted as a single well. 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 drill and complete all wells in a given "tank" before any individual well is turned to production. In certain of our producing areas, 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. As a result, multi-well pad drilling delays the completion of wells and the commencement of production. In addition, existing wells that offset new wells being completed by QEP or offset operators may need to be temporarily shut-in during the completion process. Such delays and well shut-ins have caused and may continue to cause volatility in QEP's quarterly operating results. In addition, delays in completion of wells have and continue to impact planned conversion of PUD reserves to proved developed reserves. QEP had 42 gross operated wells waiting on completion as of December 31, 2017.

Delivery Commitments

QEP is a party to various long-term sales commitments for physical delivery of oil and gas with future firm delivery commitments as follows:

Period	Delivery Commitments (MMboe)
2018	12.0
Thereafter	—

These commitments are physical delivery obligations with prices based on prevailing index prices for oil and gas at the time of delivery. None of these commitments requires the Company to deliver oil or gas produced specifically from any of the Company's properties. The Company believes that its production and reserves should be adequate to meet these term sales commitments. If the Company's oil or gas production is not sufficient to satisfy its firm delivery commitments, the Company believes it can purchase sufficient volumes of oil or gas in the market at index-related prices to satisfy its commitments. 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 and storage commitments related to oil and gas deliveries.

In addition, at December 31, 2017, 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 59%, 48%, and 30%, in the aggregate, of QEP's revenues for the years ended December 31, 2017, 2016 and 2015, respectively. During the year ended December 31, 2017, Shell Trading Company, Occidental Energy Marketing, Andeavor Logistics LP, BP Energy Company and Plains Marketing LP accounted for 14%, 13%, 13%, 10% and 10%, respectively, of QEP's total revenues. During the year ended December 31, 2016, Shell Trading Company, BP Energy Company and Valero Marketing & Supply Company accounted for 14%, 10% and 10%, respectively, of QEP's total revenues. During the year ended December 31, 2015, no customer 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.

Competition

QEP faces competition in every facet of its business, including the acquisition of producing leaseholds, wells and undeveloped leaseholds, the marketing of oil, 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 both December 31, 2017 and 2016, QEP had 656 employees. None of QEP's employees are represented by unions or covered by collective bargaining agreements.

Executive Officers of the Registrant

The name, age, period of service, title and business experience of each of QEP's executive officers as of January 31, 2018, are listed below:

Charles B. Stanley	59	Chairman (2012 to present). President and Chief Executive Officer (2010 to present). Previous titles with Questar Corporation: Chief Operating Officer (2008 to 2010); Executive Vice President and Director (2003 to 2010); President, Chief Executive Officer and Director, Market Resources and Market Resources subsidiaries (2002 to 2010).
Richard J. Doleshek	59	Executive Vice President and Chief Financial Officer (2010 to present). Treasurer (2010 to 2014). Chief Accounting Officer (2013 to 2014). Previous titles with Questar Corporation: Executive Vice President and Chief Financial Officer (2009 to 2010). Prior to joining Questar, Mr. Doleshek was Executive Vice President and Chief Financial Officer at Hilcorp Energy Company (2001 to 2009).
Jim E. Torgerson	54	Executive Vice President, QEP Energy (2013 to Present). Senior Vice President - Operations (2012 to 2013). Senior Vice President, Drilling and Completions (2011 to 2012). Previous titles with Questar Corporation: Vice President, Drilling and Completions (2009 to 2010); Vice President, Rockies Drilling and Completions (2005 to 2008).
Christopher K. Woosley	48	Senior Vice President and General Counsel (2017 to present). Vice President and General Counsel (2012 to 2016). Corporate Secretary (2016 to 2017). Senior Attorney (2010 to 2012). Prior to joining QEP, Mr. Woosley was a partner in the law firm Cooper Newsome & Woosley PLLP (2003 to 2010).
Margo D. Fiala	54	Vice President, Human Resources (2010 to present). Prior to joining QEP, Ms. Fiala was the Director of Human Resources at Suncor Energy USA (2004 to 2010) and held a variety of Human Resources roles in Canada previously at Suncor Energy Inc. (1995-2003).
Alice B. Ley	44	Vice President, Controller and Chief Accounting Officer (2014 to present). Interim Controller (2013-2014). Director of Financial Reporting (2012 to 2013). Prior to joining QEP, Ms. Ley was an Accounting/Financial Analyst Manager at Frontier Oil Corporation (2001 to 2011).

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

Government Regulation

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

Regulation of Exploration and Production Activities

The regulation of oil and gas exploration and production 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 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. 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 and on the Uintah and Ouray Indian Reservations in the Uinta 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. However, the FIP does not apply in areas of ozone nonattainment. As a result, the EPA may impose area-specific regulations in parts of the Uinta Basin identified as tribal lands that may require additional emissions controls on existing equipment as a result of expected designation of a portion of the Uinta Basin as a nonattainment area for ozone. Upon designation of the Uinta Basin as a nonattainment area under the Clean Air Act, the current FIP and its permit-by-rule process will no longer apply to the nonattainment area, and permits may take longer and be costly to obtain until the EPA finalizes a FIP specific to the Uinta Basin.

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 and/or state or regional GHG cap and trade programs.

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 regulating the venting and flaring of natural gas, leak detection, air emissions from equipment, well maintenance and unloading, drilling and completions and royalties potentially owed for loss of such emissions from oil and gas facilities producing on federal and tribal leases. Certain provisions of the final rule took effect in January 2017 while other provisions had a compliance deadline of January 2018. In December 2017, the BLM delayed the obligations to comply with certain provisions of the rule until January 2019. On February 22, 2018, a United States District Court for the Northern District of California preliminarily enjoined the BLM's decision to delay the rule's compliance obligations, requiring QEP and other operators to comply immediately with the rule.

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 them to obtain numbers for all onshore points of federal royalty measurement from the BLM, adjusting recordkeeping requirements, and 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." These laws also require the preparation and implementation of Spill Prevention, Control, and Countermeasure Plans in connection with on-site storage of significant quantities of oil. The scope of what areas constitute jurisdictional waters of the United States regulated under the Clean Water Act is currently entangled in ongoing litigation and related administrative matters that are not expected to be resolved for several years. In the meantime, the EPA and the U.S. Army Corps of Engineers (Corps) are expected to determine the scope of such regulated areas much as they have over the last decade. 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, treatment, and release of water produced or used during oil and gas development, including via underground injection control disposal wells.

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 repairs 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.

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 damages to natural resources. Such liability is in addition to claims for personal injury and property damage allegedly 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 the 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 environmental nongovernmental organizations (ENGOs). The consent decree requires the EPA to review and determine whether it will revise the RCRA regulations for exploration and production waste to treat such waste as hazardous waste. The EPA must complete its review and make its decision regarding revision by March 2019. If the EPA chooses to revise the applicable RCRA regulations, it must sign a notice taking final action related to the new regulation by July 2021.

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

QEP obtains water for fracture stimulations from a variety of sources, including industrial water wells and surface water sources. When technically and economically feasible, QEP recycles flow-back and produced water for use in fracture stimulation, which reduces water consumption from surface and groundwater sources and reduces produced water disposal volumes. QEP also employs additional measures, when available, to protect water quality such as using hydrocarbon free lubricants in water well construction, locking all inactive water wells to prevent unauthorized use, and transporting both fresh and produced water by pipeline instead of truck when feasible to avoid truck traffic and emissions. QEP believes that the employment of fracture stimulation technology does not present any significant additional risks other than those associated with the disposal of waste water (see Item 1A - Risk Factors for additional 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. States are updating legislative and regulatory requirements for hydraulic fracturing with increasing frequency. 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 is 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 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. In 2016, the Occupational Safety and Health Administration (OSHA) adopted employee-protection requirements regarding silica, which is used in hydraulic fracturing fluids.

In the event that new or more stringent federal, state or local regulations, restrictions or moratoria are adopted in areas where QEP operates, QEP could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling or stimulating wells in some areas.

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

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

Emergency Planning and Community Right-to-Know Act and Occupational Safety and Health Act. The Emergency Planning and Community Right-to-Know Act (EPCRA) requires certain facilities to disseminate information on chemical inventories to employees as well as local emergency planning committees and emergency response departments. In January 2017, the EPA issued proposed rules to add natural gas processing facilities to the list of facilities that must report under EPCRA, which have not been finalized. The federal Occupational Safety and Health Act establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communication programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures.

Regulation of Underground Storage

QEP, through its wholly owned subsidiary Clear Creek Storage Company, LLC (Clear Creek), operates an underground gas storage facility under the jurisdiction of the FERC. Clear Creek is subject to specific FERC regulations governing interstate transmission facilities and activities, including but not limited to rates charged for transmission, open access/non-discrimination, and public disclosure via an electronic bulletin board of daily capacity and flows. The FERC establishes rates for the storage of natural gas. The FERC also regulates, among other things, the extension and enlargement or abandonment of jurisdictional natural gas facilities. Regulation is intended to permit the recovery, through rates, of the cost of service, including a return on investment. In December 2016, the Pipeline and Hazardous Materials Safety Administration published an Interim Final Rule governing safety at underground natural gas storage facilities. The rule required adoption of American Petroleum Institute Recommended Practices for depleted reservoir storage facilities by January 2018, which was a highly compressed time frame, especially for smaller facilities like Clear Creek.

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. In Haynesville/Cotton Valley, QEP owns, or holds interests in, a number of pipelines that it asserts are non-jurisdictional gathering lines (under FERC guidelines). However, because there is no bright-line jurisdictional test, the distinction between non-jurisdictional gathering and FERC-regulated transmission pipelines may be the subject of disputes and litigation, and the jurisdictional status may change. QEP's gas gathering system is not currently subject to state 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 the crude oil is transported in interstate or foreign commerce, whether by QEP's pipelines or other means of transportation (pursuant to the Interstate Commerce Act, the Energy Policy Act of 1992 and related rules). QEP does not control the entire transportation path of all crude oil shipped on QEP's pipelines. Therefore, FERC regulation could be triggered by QEP's customers' transportation decisions.

Regulation of Pipeline Safety. QEP's pipeline operations are subject to regulation by the Department of Transportation, through the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended (NGPSA), with respect to natural gas and the Hazardous Liquids Pipeline Safety Act of 1979, as amended (HLPSA), with respect to crude oil. The NGPSA and HLPSA, as amended, govern the design, installation, testing, construction, operation, replacement and management of natural gas as well as crude oil, NGL and condensate pipeline facilities.

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

State Regulations

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

Texas. In 2014, the TRRC adopted new permit rules for injection wells to address seismic activity concerns within the state. Among other things, the rules require companies seeking permits for 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 specific well integrity, casing, and cementing requirements for hydraulically fractured wells. In 2016, the TRRC conformed administrative practices and procedures for horizontally drilled and fractured fields to those applicable to other types of development.

North Dakota. The North Dakota Industrial Commission (the NDI Commission), North Dakota's chief energy regulator, issued an order in June 2014 to reduce the volume of natural gas flared from oil wells in the Bakken and Three Forks formations. In connection with that order, the NDI Commission required operators to develop gas capture plans that describe how much natural gas is expected to be produced, how it will be delivered to a processor and where it will be processed. Production caps or penalties are imposed on certain wells that cannot meet the capture goals. In addition, pursuant to Commission Order No. 25417 we are required to condition crude oil produced in the Bakken Petroleum System to remove lighter, volatile hydrocarbons and reduce the vapor pressure of crude oil.

Utah. Utah's Department of Environmental Quality (UDEQ) has experienced significant delays and backlogs in the processing of air permits for oil and gas activities. Further, UDEC was concerned there were hundreds of non-compliant oil and gas facilities in operation. To address these issues, the Utah Air Quality Board voted to approve a new Permit by Rule (PBR) proposed by the Utah Division of Air Quality (UDAQ) in January 2018. The PBR (proposed September 6, 2017) requires emission controls for tanks, dehydrators and tank truck loading operations, as well as leak detection and repair and engine requirements for new sources and existing sources above specific emission thresholds. The PBR also mandates an emission source registration and triennial emissions inventory. In 2016, Utah's Governor and the Ute Tribe made recommendations to the EPA regarding the designation of a portion of the Uinta Basin as nonattainment for the eight-hour ozone National Ambient Air Quality Standard. In December 2017, the EPA responded to Utah and the Ute Tribe's nonattainment recommendation for the Uinta Basin and indicated that the EPA intends to expand the recommended nonattainment area in the Uinta Basin to include portions of five counties (including both state and tribal land) by the end of April 2018. That designation will likely result in further scrutiny of air quality permitting and additional control of emissions through the permitting programs applicable to QEP, as implemented by the UDEQ and EPA.

Other Regulations

Dodd-Frank Wall Street Reform and Consumer Protection Act. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) is designed to provide a comprehensive framework for the regulation of the over-the-counter derivatives market with the intent to provide greater transparency and reduction of risk between counterparties. The Dodd-Frank Act subjects certain participants to capital and margin requirements and requires many derivative transactions to be cleared on exchanges. The Dodd-Frank Act provides for an exemption from these clearing and cash collateral requirements for commercial end-users. See Part I, Item 1A - Risk Factors, in this Annual Report on Form 10-K for more information.

Reporting and Payment of Federal Royalties. The Department of Interior, Office of Natural Resources Revenue (ONRR), is responsible for collecting royalties on gas produced from Federal and Indian lands. In August 2016, the ONRR revised its civil penalty regulations, making it easier for the ONRR to issue civil penalties for incorrectly reporting production and incorrectly paying royalties on federal and tribal leases.

U.S. Tax Reform Legislation. On December 22, 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 Tax Legislation also repeals the corporate alternative minimum tax (AMT). Several provisions of the new tax law such as limitations on the deductibility of interest expense and certain executive compensation and the inability to use Section 1031 like-kind exchanges for assets such as machinery and equipment could apply to QEP; however, we do not believe that they will materially impact QEP's financial statements. 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. The Company will continue to analyze the Tax Legislation to determine the full impact of the new law, on the Company's consolidated financial statements and operations.

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.

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, including the ability of members of OPEC to maintain oil price and production controls;
- political and economic conditions and events in the United States and in or affecting other producing countries, including conflicts in the Middle East, Africa, South America and Russia;
- the strength of the U.S. dollar relative to other currencies;
- weather conditions and natural disasters;
- domestic and international laws, regulations and taxes, including regulations or legislation relating to climate change, induced seismicity or oil and gas exploration and production activities;
- technological advances affecting energy consumption and energy supply;
- conservation efforts;
- the price, availability and acceptance of alternative energy sources, including coal, nuclear energy, renewables and biofuels;
- demand for electricity and natural gas used as fuel for electricity generation;
- the level of global oil, gas and NGL inventories and exploration and production activity; and
- the quality of oil and gas produced.

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

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

Lower oil, gas and NGL prices or negative adjustments to oil, gas and NGL reserves may result in significant impairment charges. Lower commodity prices may not only decrease QEP's revenues, operating income and cash flows but also may reduce the amount of oil, gas and NGL that QEP can produce economically. GAAP requires QEP to write down, as a non-cash charge to earnings, the carrying value of its oil and gas properties in the event QEP has impairments. QEP is required to perform impairment tests on its assets periodically and whenever events or changes in circumstances warrant a review of its assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of its assets, the carrying value may not be recoverable, and, therefore, a write-down may be required. During the years ended December 31, 2017, 2016 and 2015, QEP recorded impairment charges of $38.1 million, $1,172.7 million and $39.3 million, respectively, on its proved properties and $29.0 million, $17.9 million and $2.0 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, 2017 and goodwill impairment of $5.3 million, $3.7 million and $14.3 million during the years ended December 31, 2017, 2016 and 2015, respectively. Refer to Part I, Item 8, Note 1 – Summary of Significant Accounting Policies, of this Annual Report on Form 10-K for additional information.

If forward oil prices decline from December 31, 2017 levels or we experience negative changes to the estimated reserve quantities, we have proved and unproved properties with a net book value of approximately $2.7 billion, as of December 31, 2017, at risk for impairment, primarily associated with our Williston Basin. 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 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 and geological interpretation and judgment. Reserve estimates are imprecise and will change as additional information becomes available. Estimates of economically recoverable reserves and future net cash flows prepared by different engineers or by the same engineers at different times may vary significantly. Results of subsequent drilling, testing and production may cause either upward or downward revisions of previous estimates. In addition, the estimation process involves economic assumptions relating to commodity prices, operating costs, severance and other taxes, capital expenditures and remediation costs. Actual results most likely will vary from the estimates. Any significant variance from these assumptions could affect the recoverable quantities of reserves attributable to any particular property, the classifications of reserves, the estimated future net cash flows from proved reserves and the present value of those reserves.

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

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

Our use of seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations. Even when properly used and interpreted, seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether producible hydrocarbons are, in fact, present in those structures in economic quantities. In addition, the use of 3-D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

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

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

- injuries and/or deaths of employees, supplier personnel, or other individuals;
- fire, explosions and blowouts;
- earthquakes and other natural disasters;
- aging infrastructure and mechanical problems;
- unexpected drilling conditions, including abnormally pressured formations or loss of drilling fluid circulation;
- pipe, cement or casing failures;
- equipment malfunctions and/or mechanical failure;
- theft or vandalism of oilfield equipment and supplies, especially in areas of increased activity;
- severe weather;
- plant, pipeline, railway and other facility accidents and failures;
- truck and rail loading and unloading problems;
- 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; and
- title problems.

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

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

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

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

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

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

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

QEP began testing the restimulation, or refracturing, of wells in Haynesville/Cotton Valley during 2016 and expanded the use of this technique to its Williston Basin properties during 2017. Refracturing an existing well is technically more challenging than fracturing a new well and may result in the loss of the existing producing well.

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

If our drilling and completion activities do not meet our anticipated results or we are unable to execute our drilling and completion program because of capital constraints, lease expirations, limited access to gathering systems, limited takeaway capacity and/or declines in crude oil and natural gas prices, the return on our investment for certain projects may not be as attractive as we anticipate. Further, as a result of any of these developments, we could incur material write-downs of our oil and gas properties and the value of our undeveloped acreage could decline in the future.

QEP has limited control over the activities on properties it does not operate. Other companies operate some of the properties in which QEP has an interest. QEP has limited ability to influence or control the operation or future development of these non-operated properties, including compliance with environmental, safety and other regulations, or the amount or timing of capital expenditures that QEP is required to fund with respect to them. The failure of an operator of QEP's wells to adequately perform operations, an operator's breach of the applicable agreements with QEP or an operator's failure to act in ways that are in QEP's best interest could reduce QEP's production and revenues. QEP's dependence on the operator and other working interest owners to complete these projects and QEP's limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of QEP's targeted returns on capital in drilling or acquisition activities, lead to unexpected future costs, or adversely affect the timing of activities.

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 other areas, QEP drills multiple wells from a single pad. Wells drilled on a pad are not brought into production until all wells on the pad are drilled and cased and the drilling rig is moved from the location. In addition, existing wells that offset newly drilled wells may be temporarily shut-in during the drilling and completion process. As a result, multi-well pad drilling delays the completion of wells and the commencement of production, which may cause volatility in QEP's operating results from period to period. Existing wells that offset new wells being completed by QEP or offset operators may also need to be temporarily shut-in during the completion process. Such delays and well shut-ins have caused and may continue to cause volatility in QEP's operating results from period to period. In addition, delays in completion of wells may impact planned conversion of PUD reserves to proved developed.

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

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

QEP may be required to write down its proved undeveloped reserve estimates if it is unable to convert those reserves into proved developed reserves within five years. SEC rules require that, subject to limited exceptions, proved undeveloped (PUD) reserves may only be classified as proved reserves if they are from locations scheduled to be drilled within five years after the date of booking. Recovery of PUD reserves requires the expenditure of significant capital and successful drilling operations. QEP may be required to write down its PUD reserves if it is not successful in drilling PUD wells within the required five-year time frame. During 2017 and 2016, QEP removed 8.7 MMboe and 5.4 MMboe, respectively, of PUD reserves that were no longer in the 2018 and 2017 forecasted capital expenditure plans, respectively, and would not be drilled and completed within five years of the initial date of booking of the reserves. At December 31, 2017, approximately 63% of QEP's estimated proved reserves were PUD reserves. These reserve estimates reflect the Company's plans to make significant capital expenditures to convert its PUDs into proved developed reserves, requiring an estimated $4.3 billion during the five years ending December 31, 2022. The estimated development costs may not be accurate; timing to incur such costs may change; development may not occur as scheduled; and results may not be as estimated.

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

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

QEP is required to pay fees to some of its midstream service providers based on minimum volumes regardless of actual volume throughput. QEP has contracts with some third-party service providers for gathering, processing and transportation services with minimum volume delivery commitments. As of December 31, 2017, QEP's aggregate long-term contractual obligation under these agreements was $392.9 million. QEP is obligated to pay fees on minimum volumes to service providers regardless of actual volume throughput. These fees could be significant and have a material adverse effect on QEP's results of operations.

QEP is dependent on its revolving credit facility and continued access to capital markets to successfully execute its operating strategies. If QEP is unable to make capital expenditures or acquisitions because it is unable to obtain capital or financing on satisfactory terms, QEP may experience a decline in its oil and gas production rates and reserves. QEP is partially dependent on external capital sources to provide financing for certain projects. The availability and cost of these capital sources is cyclical, and these capital sources may not remain available, or QEP may not be able to obtain financing at a reasonable cost in the future. Over the last few years, conditions in the global capital markets have been volatile, making terms for certain types of financing difficult to predict, and in certain cases, resulting in certain types of financing being unavailable. If QEP's revenues decline as a result of lower oil, gas or NGL prices, operating difficulties, declines in production or for any other reason, QEP may have limited ability to obtain the capital necessary to sustain its operations at current levels. At year end 2017, QEP had $89.0 million of borrowings under its unsecured revolving credit facility. In the past, QEP has utilized cash and its revolving credit facility, provided by a group of financial institutions, to meet short-term funding needs. Borrowings under its revolving credit facility incur floating interest rates. From time to time, QEP may use interest rate derivatives to manage the interest rate on a portion of its floating-rate debt. The interest rates for QEP's revolving credit facility are tied to QEP's ratio of indebtedness to consolidated EBITDA (as defined in the credit agreement). QEP's failure to obtain additional financing could result in a curtailment of its operations relating to exploration and development of its prospects, which in turn could lead to a possible reduction in QEP's oil or gas production, reserves and revenues, and could negatively impact QEP's results of operations.

QEP's debt and other financial commitments may limit its financial and operating flexibility. QEP's total debt was approximately $2.2 billion at December 31, 2017. 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, 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 to payments on its debt or to comply with any restrictive terms of its debt. QEP may be at a competitive disadvantage as compared to similar companies that have less debt. Higher levels of debt may make QEP more vulnerable to general adverse economic and industry conditions. Additionally, the agreement governing QEP's revolving credit facility and the indentures covering QEP's senior notes contain a number of covenants that impose constraints on the Company, including 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 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 8 – 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.

A downgrade in QEP's credit rating could negatively impact QEP's cost of and access to capital. As of February 2018, QEP's credit ratings are BB+ by Standard & Poor's Financial Services LLC (S&P), Ba3 by Moody's Investor Services, Inc. (Moody's) and BB by Fitch Ratings, Inc. (Fitch). A downgrade 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. In addition, a downgrade of QEP's credit ratings could result in a requirement for QEP to comply with an additional covenant under QEP's credit agreement, which could limit the amount of debt that QEP may incur.

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

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

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

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

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

- delay or denial of drilling and other necessary permits;
- shortening of lease terms or reduction in lease size;
- restrictions on installation or operation of gathering, processing or pipeline facilities;
- more stringent setback requirements from houses, schools and businesses;
- towns, cities, states and counties considering 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 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 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.

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, exploitation, acquisition and production. QEP faces competition from:

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

QEP faces competition in a number of areas such as:

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

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

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

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

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

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

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

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

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

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

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

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

Clean Air Act regulations at 40 C.F.R Part 60, Subpart OOOO (Subpart OOOO) became effective in 2012, with further amendments effective in 2013 and 2014. Subpart OOOO imposes air quality controls and requirements upon QEP's operations. Additionally, in June 2016, the EPA finalized closely related rules in new Subpart OOOOa to achieve additional methane and volatile organic compound reductions from certain activities in the oil and gas industry. The new rules include, among others, new requirements for finding and repairing leaks at new well sites and "reduced emission completion" requirements for hydraulically fractured oil and gas wells. The future status of Subpart OOOOa remains uncertain given ongoing litigation and administrative regulatory actions. EPA has proposed a two-year stay of the effective dates of several requirements of Subpart OOOOa, including fugitive emission requirements, well site pneumatic pump standards, and requirements for certification of closed vent systems. The rules, however, remain in effect as of the filing of this report. The regulatory uncertainty surrounding the implementation of this rule poses some complications for QEP's operations and compliance efforts. Additionally, many states are adopting air permitting and other air quality control regulations specific to oil and gas exploration, production, gathering and processing that are more stringent than existing requirements under federal regulations.

Regulatory requirements to reduce gas flaring and to further restrict emissions could have an adverse effect on our operations. Wells in the Williston Basin of North Dakota and the Permian Basin of Texas, where QEP has significant operations, produce natural gas as well as crude oil. Constraints in third party gas gathering and processing systems in certain areas have resulted in some of that natural gas being flared instead of gathered, processed and sold. In June 2014, the NDI Commission, North Dakota's chief energy regulator, adopted a policy to reduce the volume of natural gas flared from oil wells in the Williston Basin. The Commission requires operators to develop gas capture plans that describe how much natural gas is expected to be produced, how it will be delivered to a processor and where it will be processed. Production caps or penalties may be imposed on certain wells that cannot meet the capture goals. It is possible that other states will require gas capture plans in the future to reduce flaring. Additionally, in November 2016, the Bureau of Land Management (BLM) finalized a new rule related to further controls on the venting, flaring and emissions of natural gas on BLM and tribal leases (the 2016 Venting and Flaring Rule). The rule took effect in January 2017. Some provisions of the rule required compliance in January 2017, including the royalty provisions, while other provisions including those related to further controls on the venting and flaring of natural gas, did not require compliance until January 2018. The 2016 Venting and Flaring Rule is the subject of active litigation in the U.S. District Court for the District of Wyoming. In December 2017, the BLM published a rule to delay the January 2018 compliance deadlines and suspend the obligation to comply with certain provisions that had required compliance in January 2017, until January 2019 (2017 Delay Rule). Certain states and ENGOs filed litigation in the U.S. District Court for the Northern District of California challenging the 2017 Delay Rule, and the court preliminarily enjoined the 2017 Delay Rule on February 22, 2018, requiring operators to immediately comply with the 2016 Venting and Flaring Rule. These state and federal gas capture requirements, and any similar future obligations in North Dakota or our other locations, increase our operational costs and may restrict our production, which could materially and adversely affect our financial condition, results of operations and cash flows.

Rules regarding crude oil shipments by rail may pose unique hazards that may have an adverse effect on our operations. The North Dakota Industrial 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. 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. For example, the Department of the Interior's Fish and Wildlife Service (FWS) plans to issue a proposed rule listing the Lesser Prairie-Chicken as a threatened or endangered species. The Lesser Prairie-Chicken is a grouse species native to Texas, including parts of the Permian Basin where QEP operates. Additionally, the FWS released a proposed rule to list the Louisiana Pine Snake as threatened under the Endangered Species Act (ESA). They listed Bienville Parish as one of the Parishes that the snake can be found. QEP operates within Bienville Parish. The FWS is in the process of making a final determination in 2018 of whether to list under the ESA.

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 for alleged 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-ways for QEP's operations on tribal lands.

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

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

Legislation or regulatory initiatives intended to address induced seismicity could restrict QEP's drilling and production activities as well as QEP's ability to dispose of produced water gathered from such activities, which could have a material adverse effect on QEP's business. State and federal regulatory agencies have focused on a possible connection between the disposal of wastewater in underground injection wells and the increased occurrence of seismic activity in certain areas, and regulatory agencies at all levels are continuing to study the possible linkage between oil and natural gas activity and induced seismicity. For example, in 2015, the United States Geological Survey identified eight states, including Texas, with areas of increased rates of seismic activity that may be attributable to fluid injection or oil and natural gas extraction activities. In addition, a number of lawsuits have been filed, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, in October 2014, the Railroad Commission of Texas 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 indicates 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 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 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 and the regulation of greenhouse gas (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 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 and climate change may result in increased operating costs, delays in obtaining air pollution 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 climate change regulation under various laws pertaining to the environment, energy use and energy resource development. Federal, state and local governments may also pass laws mandating the use of alternative energy sources, such as wind power and solar energy, or banning the use of gasoline or diesel powered vehicles, which may reduce demand for oil and natural gas. Further, state and local governments may pursue litigation against producers for damages allegedly resulting from climate change, similar to the lawsuits filed by the cities of San Francisco and Oakland, California, in September 2017, and the lawsuit filed by the City of New York in January 2018 against Chevron Corp., ConocoPhillips, Co., ExxonMobil Corp., Royal Dutch Shell Plc and BP p.l.c.. QEP's ability to access and develop new oil and gas reserves may also be restricted by climate change regulation, including GHG reporting and regulation.

Congress has previously considered but not adopted proposed legislation aimed at reducing GHG emissions. 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 and proposed action to stay portions of those rules. Additionally, in June 2014, the United States Supreme Court upheld a portion of EPA's GHG stationary source permitting program in *Utility Air Regulatory Group v. EPA*, but also invalidated a portion of it. The Court's holding does not prevent states from considering and adopting state-only major source permitting requirements based solely on GHG emission levels. Federal and state regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with air permits or other requirements of the Clean Air Act and associated state laws and regulations to which QEP's operations are subject.

In December 2015, over 190 countries, including the U.S., reached an agreement in Paris (COP 21) to reduce global emissions of GHG (the 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. In June 2017, President Trump announced that the U.S. would initiate the formal process to withdraw from the Paris Agreement. Withdrawal will take a few years to implement due to the Paris Agreement's legal structure and language. The current state of development of ongoing international climate initiatives and any related domestic actions make it difficult to assess the timing or effect on our operations or to predict with certainty the future costs that we may incur in order to comply with future international treaties or domestic regulations. Following the initiation of the U.S. withdrawal from the Paris Agreement, state and local regulation 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. For example, in January 2018, UDEQ adopted additional rules that impose leak detection and repair requirements at certain oil and gas facilities in Utah. 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 empower ENGOs to pursue 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 as a result of global warming could also decrease demand for natural gas. To the extent that such unfavorable weather conditions are exacerbated by 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.

Our business could be negatively affected as a result of actions of activist shareholders, and such activism could impact 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. Responding to actions by activist shareholders could be costly and time-consuming, disrupting our operations and diverting the attention of our management and employees. Such activities could interfere with our ability to execute our strategic plan or realize long-term value from our assets. The perceived uncertainties as to our future direction could also make it more difficult to attract and retain qualified personnel and affect the market price and volatility of our securities.

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 have employment agreements with or maintain key-man insurance for its key management personnel. The loss of services of one or more of its key management personnel could have a negative impact on QEP's financial condition and results of operations.

In certain areas of QEP's business, institutional knowledge resides with employees who have many years of service. As these employees retire, QEP may not be able to replace them with employees of comparable knowledge and experience. QEP's efforts at knowledge transfer could be inadequate. If knowledge transfer, recruiting and retention efforts are inadequate, access to significant amounts of internal historical knowledge and expertise could become unavailable to QEP and could negatively impact QEP's business.

General economic and other conditions could negatively impact QEP's operating results. QEP's operating results may also be negatively affected by changes in global economic conditions; availability and economic viability of oil and gas properties for sale or exploration; rate of inflation and interest rates; weather and natural disasters; changes in customers' credit ratings; competition from other forms of energy and other pipeline and storage facilities; effects of accounting policies issued periodically by accounting standard-setting bodies; and terrorist attacks or acts of war.

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 (the Pension Plan), which covers 30 active and suspended participants, or 5%, of QEP's active employees and 184 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 (the 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, 2017 and 2016, it is estimated that QEP's pension plans were underfunded by $29.5 million and $43.1 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 $6.0 million and $7.2 million during the years ended December 31, 2017 and 2016, respectively, to the Pension Plan and SERP and expects to make contributions of approximately $4.7 million to these pension plans in 2018. 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, 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. As cyber incidents continue to evolve, QEP may be required to expend additional resources to continue to modify or enhance its protective measures or to investigate and remediate any information security vulnerabilities.

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

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

- a classified Board of Directors, with only approximately one-third of QEP's Board of Directors elected each year;
- advance notice requirements for shareholder proposals and nominations for elections to the Board of Directors to be acted upon at meetings of shareholders; and
- the inability of QEP shareholders to call special meetings or act by written consent.

In addition, Delaware law imposes restrictions on mergers and other business combinations between QEP and any holder of 15% or more of QEP's outstanding common stock. These provisions may deter hostile takeover attempts that could result in an acquisition of QEP that could have been financially beneficial to its shareholders.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

The Company is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business. Item 103 of the SEC's Regulation S-K requires disclosure of 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 matters below are disclosed pursuant to that requirement.

EPA Request for Information – In July 2015, QEP received an information request from the EPA pursuant to Section 114(a) of the Clean Air Act. The information request sought facts and data about certain tank batteries in QEP's Williston Basin operations. After timely responding to the information request, QEP met with the EPA to discuss this matter in November 2017. While no formal federal enforcement action has been commenced in connection with the tank batteries to date, QEP anticipates that resolution of this matter will likely result in monetary penalties and require QEP to incur additional capital expenditures to correct non-compliance issues.

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

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

Refer to Note 9 – Commitments and Contingencies in Item 8 of Part II of this Annual Report on Form 10-K for additional 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, 2018, QEP had 5,286 shareholders of record. In February 2016, in response to lower commodity prices, the Company's Board of Directors indefinitely suspended the payment of quarterly dividends. The future declaration and payment of dividends are at the discretion of QEP's Board of Directors and the amount thereof will depend on QEP's results of operations, financial condition, contractual restrictions, cash requirements, future prospects and other factors deemed relevant by the Company's Board of Directors.

The following table is a summary of the high and low sales price per share of QEP's common stock as reported on the NYSE as well as the dividends paid per share per quarter for 2017 and 2016:

	High price	Low price	Dividend
		(per share)	
2017			
First quarter	**$ 19.52**	**$ 11.69**	**$ —**
Second quarter	**13.15**	**8.78**	**—**
Third quarter	**10.43**	**7.02**	**—**
Fourth quarter	**10.62**	**7.30**	**—**
Total			**$ —**
2016			
First quarter	$ 14.27	$ 8.54	$ —
Second quarter	20.96	13.05	—
Third quarter	20.51	16.46	—
Fourth quarter	21.12	15.53	—
Total			$ —

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 2017, QEP made changes to its peer group to remove Cabot Oil & Gas Corporation due to financial characteristics that became dissimilar.

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

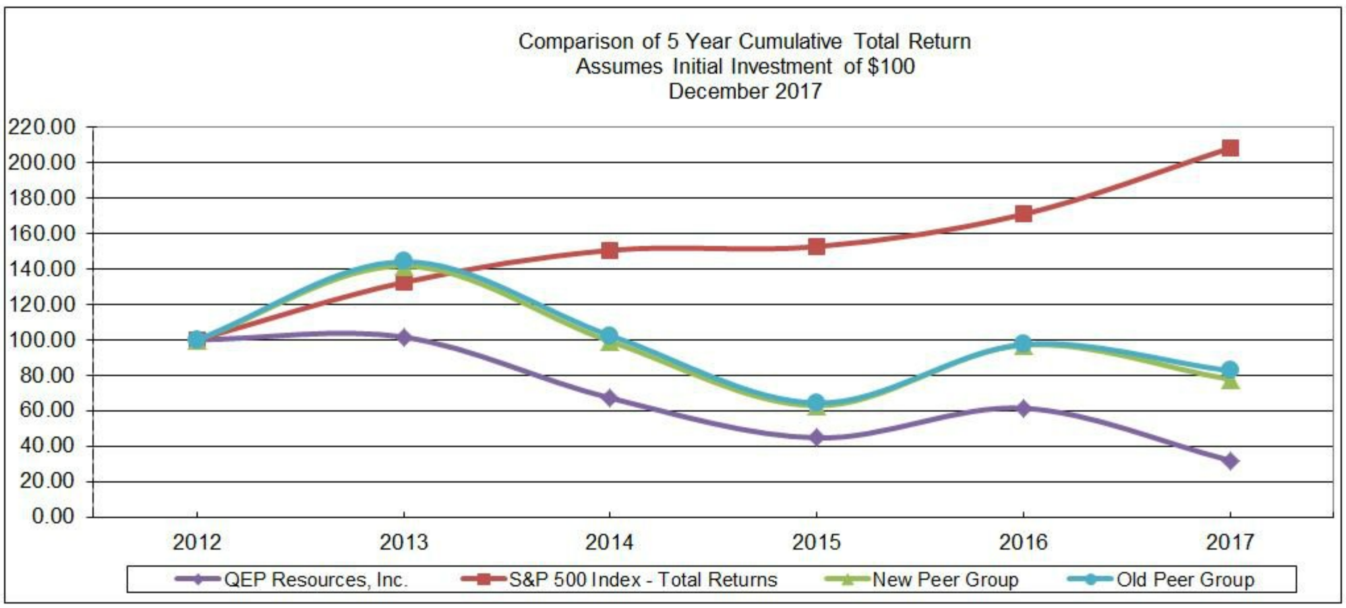
Cabot Oil & Gas Corporation	Parsley Energy, Inc.
Carrizo Oil & Gas, Inc.	PDC Energy, Inc.
Cimarex Energy Company	Range Resources Corporation
Diamondback Energy, Inc.	RSP Permian, Inc.
Energen Corporation	SM Energy Company
EP Energy Corporation	Southwestern Energy Company
Laredo Petroleum, Inc.	Whiting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

After the change in peer companies, QEP's 2017 peer group consisted of the following companies:

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

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

- A $100 investment was made in QEP's common stock, the S&P 500 Index and the Company's old and new peer groups as of December 31, 2012, and its relative performance is tracked through December 31, 2017;
- 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.



	2012	2013	2014	2015	2016	2017
QEP Resources, Inc.	$ 100.00	$ 101.53	$ 67.16	$ 44.71	$ 61.43	$ 31.93
S&P 500 Index – Total Returns	$ 100.00	$ 132.39	$ 150.51	$ 152.59	$ 170.84	$ 208.14
New Peer Group	$ 100.00	$ 141.62	$ 99.12	$ 62.86	$ 96.97	$ 77.67
Old Peer Group	$ 100.00	$ 143.99	$ 102.44	$ 64.39	$ 97.39	$ 82.50

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

The following repurchases of QEP shares were made by QEP in association with vested restricted stock awards withheld for taxes.

Period	Total shares purchased [(1)]	Weighted-average price paid per share	Total shares purchased as part of publicly announced plans or programs	Maximum value that may yet be purchased under the plans or programs
				(in millions)
October 1, 2017 – October 31, 2017	1,932	$ 8.55	—	$ —
November 1, 2017 – November 30, 2017	563	$ 8.42	—	$ —
December 1, 2017 – December 31, 2017	—	$ —	—	$ —

(1) All of the shares purchased during the three-month period ended December 31, 2017, were acquired from employees in connection with the settlement of income tax and related benefit withholding obligations arising from vesting of restricted stock grants.

In February 2018, the Board of Directors of QEP authorized the repurchase of up to $1.25 billion of the Company's outstanding shares of common stock. The timing and amount of any QEP share repurchases will be subject to available liquidity, market conditions and proceeds from the asset sales. The repurchase plan does not obligate QEP to acquire any specific number of shares and may be discontinued at any time.

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data for the five years ended December 31, 2017, is provided in the table below. Our financial results for the years ended December 31, 2016, 2015, 2014 and 2013 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 (6) to the table below). In addition, our financial results for the years ended December 31, 2014 and 2013 have been recast, in accordance with GAAP, to reflect the impact of the sale of substantially all of QEP's midstream business (see footnote (7) 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,				
	2017[(1)(2)(3)(4)]	2016[(3)(4)]	2015[(4)]	2014[(4)]	2013
Results of Operations	(in millions, except per share amounts)				
Revenues[(5)]	**$ 1,622.9**	$ 1,377.1	$ 2,018.6	$ 3,293.2	$ 2,685.1
Operating income (loss)[(6)]	**101.5**	(1,600.7)	(364.5)	(840.3)	211.9
Income (loss) from continuing operations	**269.3**	(1,245.0)	(149.4)	(409.5)	52.1
Net income from discontinued operations, net of income tax[(7)]	**—**	—	—	1,193.9	107.3
Net income (loss)[(8)]	**269.3**	(1,245.0)	(149.4)	784.4	159.4
Earnings (loss) per common share[(8)]					
Basic from continuing operations	**$ 1.12**	$ (5.62)	$ (0.85)	$ (2.28)	$ 0.29
Basic from discontinued operations[(7)]	**—**	—	—	6.64	0.60
Basic total	**$ 1.12**	$ (5.62)	$ (0.85)	$ 4.36	$ 0.89
Diluted from continuing operations[(8)]	**$ 1.12**	$ (5.62)	$ (0.85)	$ (2.28)	$ 0.29
Diluted from discontinued operations[(7)]	**—**	—	—	6.64	0.60
Diluted total	**$ 1.12**	$ (5.62)	$ (0.85)	$ 4.36	$ 0.89
Weighted-average common shares outstanding					
Used in basic calculation	**240.6**	221.7	176.6	179.8	179.2
Used in diluted calculation	**240.6**	221.7	176.6	179.8	179.5
Dividends per common share	**$ —**	$ —	$ 0.08	$ 0.08	$ 0.08
Financial Position					
Total Assets at December 31,	**$ 7,394.8**	$ 7,245.4	$ 8,398.2	$ 9,256.4	$ 9,380.4
Capitalization at December 31,					
Long-term debt	**2,160.8**	2,020.9	2,191.5	2,187.7	2,969.0
Total equity	**3,797.9**	3,502.7	3,947.9	4,075.3	3,876.8
Total Capitalization	**$ 5,958.7**	$ 5,523.6	$ 6,139.4	$ 6,263.0	$ 6,845.8
Cash Flow From Operations					
Net cash provided by (used in) operating activities	**$ 598.4**	$ 663.7	$ 481.3	$ 1,542.5	$ 1,191.7
Capital expenditures	**(1,974.8)**	(1,208.1)	(1,239.4)	(2,726.4)	(1,602.6)
Net cash provided by (used in) investing activities	**(1,168.0)**	(1,179.1)	(1,217.6)	578.2	(1,441.5)
Net cash provided by (used in) financing activities	**125.8**	583.1	(47.7)	(990.6)	279.8
Non-GAAP Measure					
Adjusted EBITDA[(6)(9)]	**$ 736.1**	$ 628.1	$ 1,031.2	$ 1,589.7	$ 1,545.6

(1) During the year ended December 31, 2017, the results are impacted by the 2017 Permian Basin Acquisition, which occurred in October 2017. Refer to Note 2 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K for detailed information on the 2017 Permian Basin Acquisition.

[2] During the year ended December 31, 2017, the results are impacted by the Pinedale Divestiture, which occurred in September 2017. Refer to Note 2 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K for detailed information on the Pinedale Divestiture.

[3] During the years ended December 31, 2017 and 2016, the results are impacted by the 2016 Permian Basin Acquisition, which occurred in October 2016. Refer to Note 2 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K for additional information on the 2016 Permian Basin Acquisition.

[4] During the years ended December 31, 2017, 2016, 2015 and 2014, the results are impacted by the 2014 Permian Basin Acquisition, which occurred in February 2014, and the property sales in the Other Southern area, beginning in the second quarter of 2014.

[5] 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.

[6] 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 all prior periods shown. 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 11 – Employee Benefits, in Item 8 of Part II of this Annual Report on Form 10-K for additional information.

[7] In December 2014, QEP sold substantially all of QEP's midstream business. The results of operations of QEP's midstream business (excluding results of Haynesville Gathering) have been reflected as discontinued operations and results for the years ended December 31, 2014 and 2013, have been reclassified.

[8] 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.

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

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

	Year Ended December 31,				
	2017	2016	2015	2014	2013
			(in millions)		
Net income (loss)	**$ 269.3**	$ (1,245.0)	$ (149.4)	$ 784.4	$ 159.4
Net income from discontinued operations, net of tax	**—**	—	—	(1,193.9)	(107.3)
Net income (loss) from continuing operations	**269.3**	(1,245.0)	(149.4)	(409.5)	52.1
Interest expense	**137.8**	143.2	145.6	169.1	165.1
Interest and other (income) expense[(1)]	**(1.6)**	(23.7)	10.1	(5.8)	(6.3)
Income tax provision (benefit)	**(312.2)**	(708.2)	(93.6)	(232.5)	60.1
Depreciation, depletion and amortization	**754.5**	871.1	881.1	994.7	963.8
Unrealized (gains) losses on derivative contracts	**(40.0)**	367.0	183.7	(374.4)	88.7
Exploration expenses	**22.0**	1.7	2.7	9.9	11.9
Net (gain) loss from asset sales	**(213.5)**	(5.0)	(4.6)	148.6	(103.5)
Impairment	**78.9**	1,194.3	55.6	1,143.2	93.0
Loss from early extinguishment of debt	**32.7**	—	—	2.0	—
Other[(1)(2)]	**8.2**	32.7	—	—	—
Adjusted EBITDA from continuing operations	**736.1**	628.1	1,031.2	1,445.3	1,324.9
Adjusted EBITDA from discontinued operations	**—**	—	—	144.4	220.7
Adjusted EBITDA	**$ 736.1**	$ 628.1	$ 1,031.2	$ 1,589.7	$ 1,545.6

(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 all prior periods shown. 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 11 – Employee Benefits, in Item 8 of Part II of this Annual Report on Form 10-K for additional information.

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

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

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

The following information updates the discussion of QEP's financial condition provided in its 2016 Annual Report on Form 10-K filing, and analyzes the changes in the results of operations between the years ended December 31, 2017 and 2016, and between the years ended December 31, 2016 and 2015.

OVERVIEW

QEP Resources, Inc. is an independent crude oil and natural gas exploration and production company with operations in two regions of the United States: the Northern Region (primarily in North Dakota and Utah) and the Southern Region (primarily in Texas and Louisiana). 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".

While historically the Company has been more natural gas weighted, in recent years the Company has increased its focus on growing its oil and NGL production. Since the beginning of 2012, the Company has made approximately $3.9 billion of acquisitions of oil-weighted properties, spent approximately 60% of its capital expenditures (excluding property acquisitions) on its oil-weighted properties, and divested gas-weighted properties, such as Pinedale. Compared to 2011, the Company's 2017 oil production has grown 424% and the Company's 2017 oil and NGL production represented 47% of total production compared to 14% in 2011. Additionally, oil and NGL revenue represented 68% of total field-level revenues during 2017 compared to 27% in 2011. Approximately 56% of total proved reserves at year-end 2017 were oil and NGL. Consistent with its emphasis on oil-weighted properties, QEP now reflects its production and reserve amounts in oil equivalent volumes rather than gas equivalent volumes. In February 2018, QEP's Board of Directors has unanimously approved several strategic initiatives including plans to market its assets in the Williston Basin, the Uinta Basin and Haynesville/Cotton Valley and focus its activities in the Permian Basin.

Acquisitions and Divestitures

While QEP believes its extensive inventory of identified drilling locations provides a solid base for growth in production and reserves, the Company continues to evaluate and acquire properties in its existing areas of operations to add additional acreage and facilitate the drilling of long lateral wells. QEP believes that its experience, expertise and presence in its core operating areas, combined with its financial strength, enhances its ability to pursue acquisition opportunities. The Company continuously evaluates potential acquisition, divestiture and joint venture opportunities that align with its strategic objectives.

Acquisitions

In the fourth quarter of 2017, QEP acquired additional oil and gas properties in the Permian Basin for an aggregate purchase price of $720.7 million, subject to post-closing purchase price adjustments. The 2017 Permian Basin Acquisition consists of approximately 15,100 acres, mainly in Martin County, Texas, which are held by production from existing vertical wells. QEP structured the transaction as a like-kind exchange under Section 1031 of the Internal Revenue Service Code and funded the purchase price with the proceeds from the sale of QEP's Pinedale assets. In addition, QEP has made offers to various persons who own additional oil and gas interests in certain properties included in the 2017 Permian Basin Acquisition on substantially the same terms and conditions as the original purchase. If all offers are accepted, QEP now expects that the aggregate purchase price will not exceed $50.0 million. In February 2018, QEP entered into agreements related to these offers for an aggregate purchase price of $36.1 million, subject to customary purchase price adjustments. The transactions and remaining offers, if accepted, are expected to be funded with borrowings under the credit facility and are expected to close in the first half of 2018. 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 October 2016, QEP acquired oil and gas properties in the Permian Basin for an aggregate purchase price of approximately $591.0 million. The 2016 Permian Basin Acquisition consisted of approximately 9,600 net acres in Martin County, Texas, which are primarily held by production from existing vertical wells. The 2016 Permian Basin Acquisition was funded with cash on hand, which included proceeds from an equity offering in June 2016. In addition to the 2016 Permian Basin Acquisition, QEP acquired various oil and gas properties in 2016, primarily in the Permian and Williston basins, for an aggregate purchase price of $54.6 million, which included additional interests in QEP operated wells and additional undeveloped leasehold acreage.

During the year ended December 31, 2015, QEP acquired various oil and gas properties, primarily in the Permian and Williston basins, for a total purchase price of $98.3 million, which included acquisitions of additional interests in QEP operated wells and additional undeveloped leasehold acreage.

Divestitures
In September 2017, QEP sold its assets in Pinedale (the Pinedale Divestiture), for net cash proceeds (after purchase price adjustments) of $718.2 million, subject to post-closing purchase price adjustments, and recorded a pre-tax gain on sale of $180.4 million which was recorded within "Net gain (loss) from asset sales" on the Consolidated Statements of Operations. QEP also sold its Central Basin Platform assets (Central Basin Platform Divestiture) and received net cash proceeds of $3.5 million. Refer to Note 3 – Capitalized Exploratory Well Costs, in Item 8 of Part II of this Annual Report on Form 10-K for more information. In addition to the Pinedale Divestiture and the Central Basin Platform Divestiture, QEP received additional net cash proceeds of $85.1 million, primarily related to the sale of non-core properties in the Other Northern area.

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

In 2015, QEP sold its interest in certain non-core properties in the Other Southern and Other Northern areas for aggregate proceeds of $31.7 million, of which $21.8 million was cash and $9.9 million was accounts receivable.

Financial and Operating Highlights

During the year ended December 31, 2017, QEP:

- Generated net income of $269.3 million, or $1.12 per diluted share;
- Reported $736.1 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 17% increase over 2016;
- Recognized realized oil prices that were $6.07 per bbl, or 14% higher compared to 2016;
- Divested assets in Pinedale for approximately $718.2 million;
- Delivered oil equivalent production of 53.1 MMboe, a 5% decrease from 2016;
- Delivered record oil production of 6.1 MMbbls in the Permian Basin, a 52% increase over 2016;
- Reported year end total proved reserves of 684.7 MMboe, including record proved crude oil reserves of 320.5 MMbbl;
- Incurred capital expenditures (excluding property acquisitions) of $1,219.8 million, a 130% increase over 2016;
- Acquired various oil and gas properties for approximately $815.2 million, of which the vast majority of which were properties in the Permian Basin;
- Expanded our successful refracturing program in Haynesville/Cotton Valley and began refracturing wells in the Williston Basin; and
- Issued $500.0 million of senior notes and repaid $445.7 million of senior notes, which were due in the next five years; paid fees and expenses associated with the repayment and used the remainder for general corporate purposes.

Outlook

Since the commodity price downturn in late 2014, the Company has focused on operating costs, per well drilling costs and managing its liquidity while continuing its transition from a natural gas weighted company to a more balanced portfolio. We believe our balance sheet and sufficient liquidity will allow us to grow oil production, primarily in the Permian Basin.

Our total capital expenditures (excluding property acquisitions), for 2018 are expected to be approximately $1,075.0 million (excluding property acquisitions), a decrease of approximately 12% from 2017 capital expenditures. We continuously evaluate our level of drilling and completion activity in light of drilling results, commodity prices and changes in our operating and development costs and will adjust our capital spending program if necessary. See "Cash Flow from Investing Activities" for further discussion of our capital expenditures.

Factors Affecting Results of Operations

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 market 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 U.S. oil and gas production, driven by advances in drilling and completion technologies, and fluctuations in demand driven by a variety of factors.

Changes in the market prices for oil, gas and NGL directly impact many aspects of QEP's business, including its financial condition, revenues, results of operations, planned drilling and completion activity and related capital expenditures, our proved undeveloped (PUD) reserves conversion rate, liquidity, rate of growth, costs of goods and services required to drill, complete and operate wells, and the carrying value of its oil and gas properties. Historically, field-level prices received for QEP's oil and gas production have been volatile. During the past five years, the posted price for WTI crude oil has ranged from a low of $26.19 per barrel in February 2016 to a high of $110.62 per barrel in September 2013. The Henry Hub spot market price of natural gas has ranged from a low of $1.49 per MMBtu in March 2016 to a high of $8.15 per MMBtu in February 2014. If prices of oil, gas or NGL decline to early 2016 levels or further, our operations, financial condition and level of expenditures for the development of our oil and gas reserves may be materially and adversely affected.

NGL prices have also been affected by increased U.S. hydrocarbon production and insufficient domestic demand and export capacity. Prices of heavier NGL components, typically correlated to oil prices, have declined in concert with weakening oil prices. Concurrently, the lighter NGL components, ethane and propane, have experienced declines as a result of growing North American oversupply. In addition to commodity price movements, QEP's composite NGL prices are affected by ethane recovery or rejection. When ethane is recovered as a discrete NGL component instead of being sold as part of the natural gas stream, the average sales price of a NGL barrel decreases as the ethane price is generally lower than the prices of the remaining NGL components. As permitted in some of its processing agreements, QEP recovers ethane when gas processing economics support the recovery of ethane from the natural gas stream. When gas processing economics do not support ethane recovery, and processing agreements permit it to do so, QEP elects to reject ethane from the NGL stream. In instances where QEP can make an election, QEP rejected ethane during the year ended December 31, 2017, and assuming similar ethane and natural gas prices, plans to reject ethane during 2018.

Global Geopolitical and Macroeconomic Factors
QEP continues to monitor the global economy, including Europe and China's economic outlook; the Organization of Petroleum Exporting Countries (OPEC) countries oil production and policies regarding production quotas; political unrest and economic issues in South America, Asia, Europe, the Middle East, and Africa; slowing growth in certain emerging market economies; actions taken by the United States Congress and the president of the United States; the U.S. federal budget deficit; changes in regulatory oversight policy; commodity price volatility; the impact of a potential increase in interest rates; volatility in various global currencies; and other factors. A dramatic decline in regional or global economic conditions, a major recession or depression, regional political instability, economic sanctions, war, or other factors beyond the control of QEP could have a significant impact on oil, gas and NGL supply, demand and prices and the Company's ability to continue its planned drilling programs and could materially impact the Company's financial position, results of operations and cash flow from operations. In December 2015, the U.S. lifted a 40-year ban on the export of oil, giving U.S. producers access to a wider market. As a result, the U.S. may in the future become a significant exporter of oil if the necessary infrastructure is built to support oil exports. 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 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, 2017, assuming forecasted 2018 annual production of approximately 49.6 MMboe, QEP had approximately 77% of its forecasted oil production and 79% of its forecasted gas production covered with fixed-price swaps. The average swap prices for the derivative contracts could be significantly lower than the average swap prices for the derivative contracts settled in prior years and, therefore, QEP's derivative portfolio may not contribute as much to QEP's net realized prices for current and future production. See Item 7A – "Quantitative and Qualitative Disclosures about Market Risk – Commodity Price Risk Management", of Part II of this Annual Report on Form 10-K for further details concerning QEP's commodity derivatives transactions.

Potential for Future Asset Impairments
The carrying values of the Company's properties are sensitive to declines in oil, gas and NGL prices as well as increases in various development and operating costs and expenses and, therefore, are at risk of impairment. The Company uses a cash flow model to assess its proved properties for impairment. The cash flow model includes numerous assumptions, including estimates of future oil, 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.

We base our fair value estimates on projected financial information that we believe to be reasonably likely to occur. 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. 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, 2017, the Company recorded impairments of $78.9 million primarily due to impairments of proved properties in the Other Northern area, underground gas storage facility and unproved properties in the Permian Basin. During the year ended December 31, 2016, impairments were $1,194.3 million primarily due to impairments of proved properties in Pinedale. During the year ended December 31, 2015, impairments were $55.6 million primarily due to impairments of proved properties in the Other Southern and Other Northern areas and goodwill associated with lower future prices. For additional 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, 2017 levels or we experience negative changes in estimated reserve quantities, we have proved and unproved property with a net book value of approximately $2.7 billion, as of December 31, 2017, at risk for impairment, primarily associated with our Williston Basin. 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.

Multi-Well Pad Drilling
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 drill and complete all wells in a given "tank" before any individual well is turned to production. In certain of our producing areas, 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. As a result, multi-well pad drilling delays the completion of wells and the commencement of production. In addition, existing wells that offset new wells being completed by QEP or offset operators may need to be temporarily shut-in during the completion process. Such delays and well shut-ins have caused and may continue to cause volatility in QEP's quarterly operating results. In addition, delays in completion of wells may impact planned conversion of PUD reserves to proved developed reserves.

Uncertainties Related to Claims
QEP is currently subject to claims that could adversely impact QEP's liquidity, operating results, capital expenditures and financial condition, including, but not limited to those described in Item 3. Legal Proceedings in Part I 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 net income during the year ended December 31, 2017, of $269.3 million, or $1.12 per diluted share, compared to a net loss of $1,245.0 million, or $5.62 per diluted share, in 2016. The increase in net income for the year ended December 31, 2017, compared to the year ended December 31, 2016, was primarily due to a decrease in impairment expense of $1,115.4 million, a $245.8 million (18%) increase in revenues (primarily oil revenue) and an increase of $257.5 million in realized and unrealized derivative gains. Net income during the year ended December 31, 2017, was also positively impacted by a $307.9 million tax benefit, primarily due to a revaluation of our net deferred tax liability to reflect the federal rate change resulting from 35% to 21% under the new tax legislation.

QEP generated a net loss during the year ended December 31, 2016, of $1,245.0 million, or $5.62 per diluted share, compared to a net loss of $149.4 million, or $0.85 per diluted share, in 2015. The increase in net loss for the year ended December 31, 2016, compared to the year ended December 31, 2015, was primarily due to an increase in impairment expense of $1,138.7 million, a 26% decrease in average realized prices, a $183.3 million increase in unrealized losses on derivative contracts and a 17% increase in general and administrative expense. These changes were partially offset by a 2% increase in oil equivalent production, a 19% decrease in production and property taxes and a 6% decrease in lease operating expense.

Adjusted EBITDA

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. 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 would 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,		
	2017	2016	2015
		(in millions)	
Net income (loss)	**$ 269.3**	$ (1,245.0)	$ (149.4)
Interest expense	**137.8**	143.2	145.6
Interest and other (income) expense[(1)]	**(1.6)**	(23.7)	10.1
Income tax provision (benefit)	**(312.2)**	(708.2)	(93.6)
Depreciation, depletion and amortization	**754.5**	871.1	881.1
Unrealized (gains) losses on derivative contracts	**(40.0)**	367.0	183.7
Exploration expenses	**22.0**	1.7	2.7
Net (gain) loss from asset sales	**(213.5)**	(5.0)	(4.6)
Impairment	**78.9**	1,194.3	55.6
Loss from early extinguishment of debt	**32.7**	—	—
Other[(1)(2)]	**8.2**	32.7	—
Adjusted EBITDA	**$ 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 all prior periods shown. 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 11 – Employee Benefits, in Item 8 of Part II of this Annual Report on Form 10-K for additional information.

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

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

Adjusted EBITDA decreased to $628.1 million during the year ended December 31, 2016, compared to $1,031.2 million in 2015, primarily due to a 26% decrease in average realized prices. These changes were partially offset by a 2% increase in oil equivalent production, a 19% decrease in production and property taxes and a 6% decrease in lease operating expense.

Revenue

Revenue, Volume and Price Variance Analysis

The following table shows volume and price related changes for each of QEP's production-related revenue categories for the year ended December 31, 2017 compared to the years ended December 31, 2016 and 2015:

	Oil	Gas	NGL	Total
Production revenues	(in millions)			
Year ended December 31, 2015	$ 834.2	$ 468.5	$ 80.0	$ 1,382.7
Changes associated with volumes[1]	30.2	(10.6)	21.6	41.2
Changes associated with prices[2]	(95.3)	(40.8)	(18.1)	(154.2)
Year ended December 31, 2016	$ 769.1	$ 417.1	$ 83.5	$ 1,269.7
Changes associated with volumes[1]	**(25.5)**	**(18.4)**	**(8.5)**	**(52.4)**
Changes associated with prices[2]	**195.8**	**95.3**	**36.9**	**328.0**
Year ended December 31, 2017	**$ 939.4**	**$ 494.0**	**$ 111.9**	**$ 1,545.3**

(1) The revenue variance attributed to the change in volume is calculated by multiplying the change in volumes from the years ended December 31, 2017 and 2016, as compared to the years ended December 31, 2016 and 2015, by the average field-level price for the years ended December 31, 2016 and 2015.

(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, 2017 and 2016, as compared to the years ended December 31, 2016 and 2015, by the respective volumes for the years ended December 31, 2017 and 2016. Pricing changes are driven by changes in commodity field-level prices, excluding the impact from commodity derivatives.

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

	Year Ended December 31,			Change	
	2017	2016	2015	**2017 vs 2016**	2016 vs 2015
Oil (per bbl)					
Average field-level price	**$ 47.88**	$ 37.90	$ 42.59	**$ 9.98**	$ (4.69)
Commodity derivative impact	**0.34**	4.25	18.06	**(3.91)**	(13.81)
Net realized price	**$ 48.22**	$ 42.15	$ 60.65	**$ 6.07**	$ (18.50)
Gas (per Mcf)					
Average field-level price	**$ 2.92**	$ 2.36	$ 2.59	**$ 0.56**	$ (0.23)
Commodity derivative impact	**(0.13)**	0.25	0.57	**(0.38)**	(0.32)
Net realized price	**$ 2.79**	$ 2.61	$ 3.16	**$ 0.18**	$ (0.55)
NGL (per bbl)					
Average field-level price	**$ 20.85**	$ 13.97	$ 16.98	**$ 6.88**	$ (3.01)
Commodity derivative impact	**—**	—	—	**—**	—
Net realized price	**$ 20.85**	$ 13.97	$ 16.98	**$ 6.88**	$ (3.01)
Average net equivalent price (per Boe)					
Average field-level price	**$ 29.08**	$ 22.76	$ 25.38	**$ 6.32**	$ (2.62)
Commodity derivative impact	**(0.29)**	2.35	8.39	**(2.64)**	(6.04)
Net realized price	**$ 28.79**	$ 25.11	$ 33.77	**$ 3.68**	$ (8.66)

December 31, 2017 compared to December 31, 2016

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

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

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

December 31, 2016 compared to December 31, 2015

Oil sales. Oil sales were $769.1 million for the year ended December 31, 2016, a decrease of $65.1 million, or 8%, compared to 2015. This decrease was a result of an 11% decrease in average field-level oil prices, partially offset by a 4% increase in oil production volumes. The decrease in average field-level oil prices was driven by a decrease in average NYMEX WTI and ICE Brent oil prices for the comparable period. The 4% increase in oil production volumes was primarily driven by an increase in the Permian Basin due to continued development drilling partially offset by a decrease in the Williston Basin due to fewer net well completions in 2016 compared to 2015.

Gas sales. Gas sales were $417.1 million for the year ended December 31, 2016, a decrease of $51.4 million, or 11%, compared to 2015. This decrease was a result of a 9% decrease in average field-level prices and a 2% decrease in gas production volumes. The decrease in average field-level gas prices was driven by a decrease in average NYMEX-HH natural gas prices for the comparable period. The 2% decrease in production volumes was primarily driven by production decreases in Pinedale due to fewer net well completions resulting from a lower rig count in 2016 compared to 2015 and in the Other Southern area due to the continued divestitures of properties. These decreases were partially offset by increased production in the Williston Basin due to higher gas recovery from a midstream provider in 2016.

NGL sales. NGL sales were $83.5 million for the year ended December 31, 2016, an increase of $3.5 million, or 4%, compared to 2015. This increase was primarily a result of a 27% increase in production volumes, partially offset by an 18% decrease in average field-level prices. The 27% increase in NGL production volumes was primarily driven by increases in the Williston and Permian basins. The increase in the Williston Basin is due to additional ethane recovered by a midstream provider and the increase in the Permian Basin is due to continued development drilling. These increases were partially offset by decreases in Pinedale due to fewer net well completions due to a lower rig count in 2016 compared to 2015 and in the Uinta Basin due to refrigeration processing of gas in 2016 compared to cryogenic processing during a portion of 2015 as well as fewer net well completions in 2016 compared to 2015. The 18% decrease in average field-level prices was driven by receiving an increased percentage of ethane from a midstream provider on our Williston Basin production during the year ended December 31, 2016 compared to the year ended December 31, 2015. The increased percentage of ethane was the result of a midstream provider electing to operate its gas processing plant in ethane recovery.

Resale Margin and Storage Activity

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

	Year Ended December 31,			Change	
	2017	2016	2015	**2017 vs 2016**	2016 vs 2015
	(in millions)				
Purchased oil and gas sales	**$ 62.6**	$ 101.2	$ 620.8	**$ (38.6)**	$ (519.6)
Purchased oil and gas expense	**(64.3)**	(105.5)	(626.8)	**41.2**	521.3
Realized gains (losses) on gas storage derivative contracts	**—**	2.9	3.8	**(2.9)**	(0.9)
Resale margin	**$ (1.7)**	$ (1.4)	$ (2.2)	**$ (0.3)**	$ 0.8

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

Purchased oil and gas sales and expense decreased during the year ended December 31, 2016, compared to the year ended December 31, 2015, due to the termination of QEP Marketing agreements on January 1, 2016. As a result of the termination of these agreements QEP is no longer the first purchaser of other working interest owner production. As such, QEP reported lower resale revenue and expenses in the year ended December 31, 2016, compared to 2015.

Operating Expenses

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

	Year Ended December 31,			Change	
	2017	2016	2015	**2017 vs 2016**	2016 vs 2015
	(per Boe)				
Lease operating expense	**$ 5.55**	$ 4.03	$ 4.38	**$ 1.52**	$ (0.35)
Transportation and processing costs	**4.61**	5.18	5.35	**(0.57)**	(0.17)
Production and property taxes	**2.15**	1.70	2.16	**0.45**	(0.46)
Total production costs	**$ 12.31**	$ 10.91	$ 11.89	**$ 1.40**	$ (0.98)

December 31, 2017 compared to December 31, 2016

Lease operating expense (LOE). QEP's LOE increased $70.1 million, or $1.52 per Boe, during the year ended December 31, 2017 compared to 2016. The increase was driven by an increase in workovers in the Williston and Permian basins and Haynesville/Cotton Valley, power and fuel expenses, and services and supplies expenses in the Permian Basin and increased water disposal expenses in Haynesville/Cotton Valley. These increases were partially offset by a decrease in Pinedale due to the Pinedale Divestiture (Refer to Note 2 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K for more information).

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

Production and property taxes. In most states in which QEP operates, QEP pays production taxes based on a percentage of field-level revenue, except in Louisiana, where severance taxes are volume based. Production and property taxes increased $19.5 million, or $0.45 per Boe, during 2017, primarily a result of increased oil and gas revenues primarily from higher field-level prices partially offset by lower production.

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

Exploration expense. Exploration expense increased $20.3 million during the year ended December 31, 2017, compared to 2016, primarily as a result of charging $21.3 million of exploratory well costs related to the Central Basin Platform exploration project to exploration expense. During the third quarter of 2017, based on well performance and the analysis of the ultimate economic feasibility of this exploration project, QEP determined it would no longer pursue the development of the Central Basin Platform exploration project. Refer to Note 3 – Capitalized Exploratory Well Costs, in Item 8 of Part II of this Annual Report on Form 10-K for more information.

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

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

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

December 31, 2016 compared to December 31, 2015

Lease operating expense. QEP's LOE decreased $14.1 million, or $0.35 per Boe, during the year ended December 31, 2016, compared to 2015. The decrease was driven by a decrease in the Permian Basin as a result of lower workover and chemical expenses, a decrease in the Other Southern area as a result of continued divestitures of non-core properties and a decrease in the Uinta Basin due to lower maintenance and repair expenses, lower services and supplies expenses and lower workover expenses. These decreases were partially offset by an increase in the Williston Basin due to increased workovers, increased produced water disposal expenses and increased maintenance and repair expenses.

Transportation and processing costs. QEP's transportation and processing costs decreased $2.1 million, or $0.17 per Boe, during the year ended December 31, 2016, compared to 2015. The decrease in expense during 2016 was primarily attributable to additional expenses incurred in Haynesville/Cotton Valley as a result of recognizing additional fees in 2015 related to unutilized gathering and transportation capacity that was charged to QEP by the operator of wells in which QEP has a working interest. This decrease was partially offset by increases in the Permian and Williston basins due to increased production and a rate increase in the Williston Basin.

Production and property taxes. Production and property taxes decreased $22.8 million, or $0.46 per Boe, during the year ended December 31, 2016, compared to 2015, primarily a result of decreased oil and gas revenues primarily from lower field-level prices, as well as production tax refunds.

Depreciation, depletion and amortization. DD&A expense decreased $10.0 million during the year ended December 31, 2016, compared to 2015. The decrease in DD&A expense was due to decreases in Pinedale and the Williston Basin, partially offset by increases in the Permian Basin, Haynesville/Cotton Valley and the Uinta Basin. The decrease in Pinedale is primarily the result of a rate decrease due to an impairment recognized in the first quarter of 2016, combined with decreased production, while the decrease in the Williston Basin is the result of a rate decrease from increased proved reserves, partially offset by an increase in production. The increases in Haynesville/Cotton Valley and the Uinta Basin were primarily due to increased rates due to a decrease in proved reserves as well as increased production in Haynesville/Cotton Valley, while the increase in the Permian Basin was primarily due to increased production.

Impairment expense. During the year ended December 31, 2016, QEP recorded impairment charges of $1,194.3 million, compared to impairment charges of $55.6 million recorded during 2015. Of the $1,194.3 million of impairment charges recorded during 2016, $1,172.7 million was related to impairment of proved properties due to lower future oil and gas prices, $17.9 million was related to expiring leaseholds on unproved properties and $3.7 million related to an impairment of goodwill. Of the $1,172.7 million impairment on proved properties, $1,164.0 million related to Pinedale properties, $4.7 million related to Uinta Basin properties, $3.4 million related to Other Northern properties and $0.6 million related to Other Southern properties. Of the $55.6 million of impairment charges recorded during 2015, $39.3 million was related to impairment of proved properties due to lower future oil and gas prices, $2.0 million was related to expiring leaseholds on unproved properties and $14.3 million related to impairment of goodwill. Of the $39.3 million impairment on proved properties, $20.2 million related to Other Southern properties, $18.4 million related to Other Northern properties and $0.7 million related to Permian Basin properties.

General and administrative expense. During 2016, G&A expense increased $28.5 million, or 17%, compared to 2015. The increase in G&A expense in 2016 compared to 2015 was primarily due to a $32.7 million increase in legal expenses and loss contingencies and an $8.6 million increase in share-based compensation, primarily due to an increase in the mark-to-market value of the Deferred Compensation Wrap Plan and CIP. These increases were partially offset by a $6.9 million decrease in professional and outside services expenses and a $6.6 million decrease in severance payments and restructuring costs (Refer to Note 7 – Restructuring Costs, in Item 8 of Part II of this Annual Report on Form 10-K for more information).

Net gain (loss) from asset sales. During the year ended December 31, 2016, QEP recognized a gain on sale of assets of $5.0 million, compared to a gain on sale of $4.6 million during the year ended December 31, 2015. The gain on sale of assets recognized in 2016 and 2015 was primarily due to the continued divestitures of non-core properties in the Other Southern area.

Non-Operating Expenses

December 31, 2017 compared to December 31, 2016

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, 2017, gains on commodity derivative instruments were $24.5 million, of which $69.9 million were unrealized gains on derivative contracts related to production and storage contracts, $29.9 million were unrealized losses related to the Pinedale Divestiture (Refer to Note 6 – Derivative Contracts, in Item 8 of Part II of this Annual Report on Form 10-K for more information) and $15.5 million were realized losses. During 2016, losses on commodity derivative instruments were $233.0 million, of which $367.0 million were unrealized losses, partially offset by $134.0 million of realized gains.

Interest and other income (expense). Interest and other income (expense) decreased $22.1 million during the year ended December 31, 2017, compared to 2016. The decrease was primarily the result of $22.6 million of bargain purchase gains recognized in 2016 that related to acquisitions which were accounted for as a business combination under ASC 805, *Business Combinations* during the year ended December 31, 2016 (Refer to Note 2 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K for more information).

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

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

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

December 31, 2016 compared to December 31, 2015

Realized and unrealized gains (losses) on derivative contracts. During the year ended December 31, 2016, losses on commodity derivative instruments were $233.0 million, of which $367.0 million were unrealized losses, partially offset by $134.0 million in realized gains. During 2015, gains on commodity derivative instruments were $277.2 million, of which $460.9 million were realized gains, partially offset by $183.7 million in unrealized losses.

Interest and other income (expense). Interest and other income (expense) increased $33.8 million during the year ended December 31, 2016, compared to 2015. The increase was primarily the result of $22.6 million of bargain purchase gains recognized related to acquisitions which were accounted for as a business combination under ASC 805, *Business Combinations* during the year ended December 31, 2016 (Refer to Note 2 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K for more information) and a pension curtailment expense of $11.2 million recognized in the second quarter of 2015 related to a change in the Company's pension plan (Refer to Note 11 – Employee Benefits, in Item 8 of Part II of this Annual Report on Form 10-K for more information).

Interest expense. Interest expense decreased $2.4 million, or 2%, during the year ended December 31, 2016, compared to 2015. The decrease during the year ended December 31, 2016, was primarily related to the $176.8 million repayment of senior notes on September 1, 2016.

Income tax (provision) benefit. Income tax benefit increased $614.6 million during the year ended December 31, 2016, compared to 2015. The increase in income tax benefit was the result of increased net loss before income taxes, partially offset by a lower combined effective federal and state income tax rate of 36.3% during the year ended December 31, 2016, compared to 38.5% for the year ended December 31, 2015. The decrease in the rate was due to a state income tax rate change and a state return to provision adjustment.

LIQUIDITY AND CAPITAL RESOURCES

QEP strives to maintain a sufficient liquidity position to ensure financial flexibility, withstand commodity price volatility and fund its development projects, operations and capital expenditures. 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. The Company expects that these sources of cash will be sufficient to fund its operations and capital expenditures during the next 12 months and the foreseeable future.

QEP also periodically accesses debt and equity markets and sells properties. In 2018, QEP plans to market its assets in the Williston Basin, the Uinta Basin and Haynesville/Cotton Valley and, if successful, use the proceeds to fund on-going operations, reduce debt, repurchase shares and for general corporate purposes. In 2017, the Company issued $500.0 million of senior notes and used the majority of the proceeds to repay $445.7 million of senior notes; paid fees and expenses associated with the repayment and used the remainder for general corporate purposes.

QEP received aggregate proceeds of approximately $806.8 million related to the Pinedale Divestiture and the sale of properties during the year ended December 31, 2017. All of the proceeds from the Pinedale Divestiture were used to close the 2017 Permian Basin Acquisition. QEP has made offers to various persons who own additional oil and gas interests in certain properties included in the 2017 Permian Basin Acquisition on substantially the same terms and conditions as the original purchase. If all offers are accepted, QEP now expects that the aggregate purchase price will not exceed $50.0 million. In February 2018, QEP entered into agreements for an aggregate purchase price of $36.1 million, subject to customary purchase price adjustments. The transactions and any remaining offers, if accepted, are expected to be funded with borrowings under the credit facility and are expected to close in the first quarter of 2018.

In 2016, QEP issued 60.95 million shares of common stock through two public offerings and received net cash proceeds of approximately $781.4 million, which the Company used to fund the 2016 Permian Basin Acquisition and for general corporate purposes. QEP received aggregate cash proceeds of approximately $29.0 million and $21.8 million related to the sale of non-core properties during the years ended December 31, 2016 and 2015, respectively.

The Company estimates, that as of December 31, 2017, it could incur additional indebtedness of approximately $640.0 million and continue to be in compliance with the covenants contained in its revolving credit facility. 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

In November 2017, QEP entered into the Seventh Amendment to its Credit Agreement, which, among other things, reduced the aggregate principal amount of commitments to $1.25 billion and extended the maturity date, subject to satisfaction of certain conditions, to September 1, 2022. The credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions. The amended credit agreement contains financial covenants (that are defined in the credit agreement) that limit the amount of debt the Company can incur and may limit the amount available to be drawn under the credit facility including: (i) a net funded debt to capitalization ratio that may not exceed 60%, (ii) a leverage ratio under which net funded debt may not exceed 4.25 times consolidated EBITDA (as defined in the credit agreement) for the fiscal quarter ending December 31, 2017, 4.00 times commencing with the fiscal quarter ending March 31, 2018, through the fiscal quarter ending December 31, 2018, and 3.75 times thereafter, and (iii) during a ratings trigger period (as defined), a present value coverage ratio under which the present value of the Company's proved reserves must exceed net funded debt by 1.25 times at any time prior to January 1, 2019, must exceed net funded debt by 1.40 times commencing on January 1, 2019, through December 31, 2019, and must exceed net funded debt by 1.50 times at any time on or after January 1, 2020. The company is currently not subject to the present value coverage ratio. As of December 31, 2017 and 2016, QEP was in compliance with the covenants under the credit agreement.

During the year ended December 31, 2017, QEP's weighted-average interest rate on borrowings from its credit facility was 3.52%. As of December 31, 2017, QEP had $89.0 million outstanding and $1.0 million in letters of credit outstanding under the credit facility. As of December 31, 2016, QEP had no borrowings outstanding and $2.8 million in letters of credit outstanding under the credit facility. At February 23, 2018, QEP had $154.0 million of borrowings outstanding and had $1.0 million of letters of credit outstanding under the credit facility and was in compliance with the covenants under the credit agreement.

Senior Notes

During the quarter ended December 31, 2017, the Company issued $500.0 million in 5.625% Senior Notes due in 2026. The Company used the proceeds to repay $445.7 million of debt during the year ended December 31, 2017, as follows:

- $134.0 million to redeem its outstanding 6.80% Senior Notes due in 2018;
- $84.3 million of its 6.80% Senior Notes due in 2020 pursuant to a tender offer; and
- $227.4 million of its 6.875% Senior Notes due in 2021 pursuant to a tender offer.

The Company's senior notes outstanding as of December 31, 2017, totaled $2,099.3 million principal amount and are comprised of five issuances as follows:

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

Cash Flow from Operating Activities

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

Net cash provided by operating activities is presented below:

	Year Ended December 31,			Change	
	2017	2016	2015	**2017 vs 2016**	2016 vs 2015
			(in millions)		
Net income (loss)	**$ 269.3**	(1,245.0)	$ (149.4)	**$ 1,514.3**	$ (1,095.6)
Non-cash adjustments to net income	**335.8**	1,794.1	1,193.4	**(1,458.3)**	600.7
Changes in operating assets and liabilities	**(6.7)**	114.6	(562.7)	**(121.3)**	677.3
Net cash provided by operating activities	**$ 598.4**	$ 663.7	$ 481.3	**$ (65.3)**	$ 182.4

Net cash provided by operating activities during the year ended December 31, 2017, decreased $65.3 million compared to 2016, which included a $1,514.3 million increase in net income, a $1,458.3 million decrease in non-cash adjustments to net income and a $121.3 million decrease in cash from operating assets and liabilities. During the year ended December 31, 2017, non-cash adjustments to net income primarily included, DD&A expense of $754.5 million, impairment expense of $78.9 million and a $32.7 million loss from early extinguishment of debt, partially offset by deferred income taxes of $314.8 million and a $213.5 million net gain from asset sales. The decrease in changes in operating assets and liabilities of $6.7 million was primarily comprised of a $20.6 million decrease in other that predominantly included decreases in interest payable and asset retirement obligation as well as an increase in accounts receivable of $2.0 million, primarily related to timing of receipts. These decreases were partially offset by a decrease in federal income taxes receivable of $13.7 million and an increase in accounts payable and accrued expenses of $3.5 million.

Net cash provided by operating activities during the year ended December 31, 2016, increased $182.4 million compared to 2015, which included a $1,095.6 million increase in net loss, a $600.7 million increase in non-cash adjustments to the net loss and a $677.3 million increase in cash from operating assets and liabilities. During the year ended December 31, 2016, non-cash adjustments to net loss primarily included impairment expense of $1,194.3 million, DD&A expense of $871.1 million and unrealized losses on derivative contracts of $367.0 million, partially offset by a decrease in deferred income taxes of $651.3 million. The increase in changes in operating assets and liabilities primarily included a decrease in accounts receivable of $95.3 million and a decrease in income taxes receivable of $68.7 million, primarily related to a federal income tax refund received in the third quarter of 2016, partially offset by a decrease in accounts payable and accrued expenses of $50.3 million, primarily related to timing of payments and receipts.

Cash Flow from Investing Activities

A comparison of capital expenditures for the years ended December 31, 2017, 2016 and 2015, are presented in the table below:

	Year Ended December 31,			Change	
	2017	2016	2015	**2017 vs 2016**	2016 vs 2015
Property acquisitions	**$ 815.2**	$ 645.2	$ 98.3	**$ 170.0**	$ 546.9
Property, plant and equipment capital expenditures	**1,219.8**	530.1	1,011.9	**689.7**	(481.8)
Total accrued capital expenditures	**2,035.0**	1,175.3	1,110.2	**859.7**	65.1
Change in accruals and other non-cash adjustments	**(60.2)**	32.8	129.2	**(93.0)**	(96.4)
Total cash capital expenditures	**$ 1,974.8**	$ 1,208.1	$ 1,239.4	**$ 766.7**	$ (31.3)

During the year ended December 31, 2017, on an accrual basis, the Company invested $1,219.8 million on property, plant and equipment capital expenditures, excluding property acquisitions, an increase of $689.7 million compared to 2016, primarily due to increased capital expenditures in the Permian Basin and Haynesville/Cotton Valley. In 2017, QEP's capital expenditures were $704.3 million in the Permian Basin (including midstream infrastructure of $95.9 million, primarily related to fresh water supply, produced water gathering, salt water disposal, gas and oil gathering and oil terminal facilities), $283.5 million in the Williston Basin, $179.5 million in Haynesville/Cotton Valley, $22.9 million in Pinedale and $3.7 million in the Uinta Basin. In addition, during the year ended December 31, 2017, QEP acquired various oil and gas properties for a total purchase price of $815.2 million, which was primarily related to the 2017 Permian Basin Acquisition and included undeveloped leasehold acreage, producing wells and additional surface acreage in the Permian Basin. These acquisitions were primarily funded with proceeds of approximately $806.8 million from the Pinedale Divestiture and the sale of other assets.

During the year ended December 31, 2016, on an accrual basis, the Company invested $530.1 million on property, plant and equipment expenditures, excluding property acquisitions, a decrease of $481.8 million compared to 2015. In 2016, QEP's capital expenditures were $243.7 million in the Williston Basin, $141.5 million in the Permian Basin, $64.4 million in Haynesville/Cotton Valley, $54.4 million in Pinedale, $10.8 million in the Uinta Basin and $4.7 million in the Other Northern area. In addition, during the year ended December 31, 2016, QEP acquired various oil and gas properties for a total purchase price of $645.2 million, of which $639.0 million was cash and $6.2 million was non-cash related to the settlement of an accounts receivable balance. The $645.2 million of acquisitions was primarily related to the 2016 Permian Basin Acquisition and also included acquisitions of additional interests in QEP operated wells and additional undeveloped leasehold acreage in the Permian and Williston basins. These acquisitions were funded with proceeds from the June 2016 equity offering and cash on hand. Partially offsetting the acquisition capital outflow was $29.0 million of proceeds from non-core asset divestitures, primarily in the Other Southern area. In 2015, QEP's capital expenditures were $502.0 million in the Williston Basin, $215.9 million in the Permian Basin, $176.9 million in Pinedale, $68.6 million in the Uinta Basin, $36.9 million in Haynesville/Cotton Valley, $3.7 million in the Other Northern area and $3.4 million in the Other Southern area. In addition, during the year ended December 31, 2015, QEP acquired various oil and gas properties, primarily in the Williston and Permian basins, for a total purchase price of $98.3 million, which included an acquisition of additional interests in QEP operated wells and undeveloped acreage. Partially offsetting the acquisition capital outflow was $21.8 million of cash proceeds from non-core asset divestitures, primarily in the Other Southern and Other Northern areas.

The mid-point of our forecasted capital expenditures (excluding property acquisitions) for 2018 is $1,075.0 million. QEP intends to fund capital expenditures (excluding property acquisitions) with cash flow from operating activities, cash on hand and borrowings under the credit facility. The aggregate levels of capital expenditures for 2018 and the allocation of those expenditures are dependent on a variety of factors, including drilling results, oil, gas and NGL prices, industry conditions, acquisitions and divestitures, available liquidity to fund the expenditures and changes in management's business strategies. 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, 2017, net cash provided by financing activities was $125.8 million compared to net cash provided by financing activities of $583.1 million during the year ended December 31, 2016. During the year ended December 31, 2017, the Company issued 5.625% Senior Notes due 2026 receiving gross cash proceeds of $500.0 million, and repaid $445.7 million of Senior Notes comprised of the redemption of the 6.80% Senior Notes due 2018 and settling the tender offers of the 6.80% Senior Notes due 2020 and 6.875% Senior Notes due 2021. In addition, during the year ended December 31, 2017, QEP had borrowings from the credit facility of $492.0 million and repayments on its credit facility of $403.0 million. As of December 31, 2017, long-term debt consisted of $2,160.8 million total debt, of which $2,099.3 million is senior notes, $89.0 million outstanding on the credit facility, and $27.5 million of net original issue discount and unamortized debt issuance costs.

During the year ended December 31, 2016, net cash provided by financing activities was $583.1 million compared to net cash used in financing activities of $47.7 million during the year ended December 31, 2015. During the year ended December 31, 2016, the Company received net proceeds from the March and June 2016 equity offerings of $781.4 million, repaid the 6.05% Senior Notes of $176.8 million and had a decrease in checks outstanding in excess of cash balances of $17.5 million. As of December 31, 2016, long-term debt consisted of $2,045.0 million in senior notes (excluding $24.1 million of net original issue discount and unamortized debt issuance costs). As of December 31, 2016, long-term debt consisted of $2,020.9 million total debt, of which $2,045.0 million is senior notes and $24.1 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, 2017, the Company's material off-balance sheet arrangements included operating leases; drilling, gathering, processing, firm transportation and storage contracts; 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, 2017:

	Payments Due by Year[1]						
	Total	2018	2019	2020	2021	2022	After 2022
				(in millions)			
Long-term debt	$ 2,099.3	$ —	$ —	$ 51.7	$ 397.6	$ 500.0	$ 1,150.0
Interest on fixed-rate, long-term debt[2]	633.3	119.9	119.9	117.0	93.7	82.4	100.4
Drilling contracts	5.6	5.6	—	—	—	—	—
Gathering, processing, firm transportation, storage and other	394.0	90.0	68.4	54.9	29.9	28.3	122.5
Asset retirement obligations[3]	214.1	7.5	6.1	6.8	4.2	6.4	183.1
Operating leases	41.0	7.0	7.2	7.4	7.4	7.2	4.8
Total	$ 3,387.3	$ 230.0	$ 201.6	$ 237.8	$ 532.8	$ 624.3	$ 1,560.8

(1) This table excludes the Company's benefit plan liabilities as future payment dates are unknown. Refer to Note 11 – Employee Benefits, in Item 8 of Part II of this Annual Report on Form 10-K for additional 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 4 – Asset Retirement Obligations, in Item 8 of Part II in this Annual Report on Form 10-K for additional information.

Impact of Inflation/Deflation and Pricing

All of QEP's transactions are denominated in U.S. dollars. Typically, as prices for oil and gas increase, associated costs rise. Conversely, as prices for oil and gas decrease, costs decline. Cost declines tend to lag and may not adjust downward in proportion to declining commodity prices. Historically, field-level prices received for QEP's oil and gas production have been volatile. During each of the years ended December 31, 2017 and 2016, commodity prices increased from the previous year, while during the year ended December 31, 2015, commodity prices decreased from the previous year. Changes in commodity prices impact QEP's revenues, estimates of reserves, assessments of any impairment of oil and gas properties, as well as values of properties being acquired or sold. Price changes have the potential to affect QEP's ability to raise capital, borrow money, and retain personnel.

Critical Accounting Estimates

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

Oil, gas and NGL Reserves
One of the most significant estimates the Company makes is the estimate of oil, gas and NGL reserves. Oil, 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, operating expenses, severance and other taxes, capital expenditures and remediation costs. The subjective judgments and variances in data for various fields make these estimates less precise than other estimates included in the financial statement disclosures.

Estimates of proved oil, 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 amount of oil and gas properties exceeds fair value and could result in an impairment charge, which would reduce earnings. See "Impairment of Long-Lived Assets" below.

QEP engages independent reservoir engineering consultants to prepare estimates of the proved oil, 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 14 – 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.

Capitalized Exploratory Well Costs
The Company capitalizes exploratory well costs until it determines whether an exploratory well is commercial or noncommercial. If the Company deems the well commercial, capitalized costs are depreciated on a field basis using the unit-of-production method and the estimated proved developed oil, gas and NGL reserves. If the Company concludes that the well is noncommercial, well costs are immediately charged to exploration expense. Exploratory well costs that have been capitalized for a period greater than one year since the completion of drilling are expensed unless the Company remains engaged in substantial activities to assess whether the well is commercial.

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, gas and NGL reserves caused by mechanical problems, faster-than-expected decline of production, lease ownership issues and declines in oil, gas and NGL prices. If impairment is indicated, fair value is estimated using a discounted cash flow approach. Cash flow estimates require forecasts and assumptions for many years into the future for a variety of factors, including commodity prices, operating costs and estimates of proved, probable and possible reserves. Cash flow estimates relating to future cash flows from probable and possible reserves are reduced by additional risk-weighting factors. During the years ended December 31, 2017, 2016 and 2015, QEP recorded impairment expense of $38.1 million, $1,172.7 million and $39.3 million, respectively, related to some of its higher cost, proved properties in both of its Northern and Southern regions, due to lower forward prices.

Unproved properties are evaluated on a specific asset basis or in groups of similar assets, as applicable. The Company performs periodic assessments of unproved oil and gas properties for impairment and recognizes a loss at the time of impairment. In determining whether an unproved property is impaired, the Company considers numerous factors including, but not limited to, current development and exploration drilling plans, favorable or unfavorable exploration activity on adjacent leaseholds, in-house geologists' evaluation of the lease, future reserve cash flows and the remaining lease term. During the years ended December 31, 2017, 2016 and 2015, QEP recorded impairment charges of $29.0 million, $17.9 million and $2.0 million respectively, related to its unproved properties. The 2017 unproved property impairment charges primarily resulted from unproved leasehold acreage in the Central Basin Platform. Refer to Note 3 – Capitalized Exploratory Well Costs, in Item 8 of Part II of this Annual Report on Form 10-K for additional information. The 2016 and 2015 unproved property impairment charges primarily resulted from lower forward prices and expiring leaseholds.

Asset Retirement Obligations

QEP records asset retirement obligations (ARO) associated with the retirement of tangible, long-lived assets. The Company's ARO liability applies primarily to abandonment costs associated with oil and gas wells and certain other properties. The fair values of such costs are estimated by Company personnel based on abandonment costs of similar assets and depreciated over the life of the related assets. ARO is subject to revisions because of the intrinsic uncertainties present when estimating asset retirement costs and asset retirement settlement dates. Revisions to the ARO estimate can result from changes in expected cash flows or material changes in estimated asset retirement costs. The ARO liability is adjusted to present value each period through an accretion calculation using a credit-adjusted risk-free interest rate. QEP's ARO liability at December 31, 2017 and 2016 was $214.1 million and $231.6 million, respectively.

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

Revenue Recognition

QEP recognizes revenue from oil and gas producing activities in the period that services are provided or products are delivered. Revenues associated with the sale of oil, gas and NGL are accounted for using the sales method, whereby revenue is recognized as oil, gas and NGL are sold to purchasers. Revenues include estimates for the two most recent months using published commodity price indexes and volumes supplied by field operators. An imbalance liability is recorded to the extent that QEP has sold volumes in excess of its share of remaining reserves in an underlying property.

QEP also purchases and resells oil and gas primarily to mitigate losses on unutilized capacity related to firm transportation commitments and storage activities. QEP recognizes revenue from these resale activities when title transfers to the customer.

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 9 – Commitments and Contingencies, in Item 8 of Part II of this Annual Report on Form 10-K for additional information regarding litigation and other contingencies.

Environmental Obligations
Management makes judgments and estimates in accordance with applicable accounting rules when it establishes reserves for environmental remediation, litigation and other contingent matters. Provisions for such matters are expensed when it is probable that a liability has been incurred and reasonable estimates of the liability can be made. Estimates of environmental liabilities are based on a variety of factors, including, but not limited to, the stage of investigation, the stage of the remedial design, evaluation of existing remediation technologies and presently enacted laws and regulations. In future periods, a number of factors could significantly change the Company's estimate of environmental remediation costs, such as changes in laws and regulations, changes in the interpretation or administration of laws and regulations, revisions to the remedial design, unanticipated construction problems, identification of additional areas or volumes of contaminated soil and groundwater, and changes in costs of labor, equipment and technology. Consequently, it is not possible for management to reliably estimate the amount and timing of all future expenditures related to environmental matters and actual costs may vary significantly. Refer to Note 9 – Commitments and Contingencies, in Item 8 of Part II of this Annual Report on Form 10-K for additional information regarding current environmental claims.

Derivative Contracts
The Company uses commodity derivative instruments, typically fixed-price swaps and costless collars, to reduce the impact of potential downward movements in commodity prices. Accounting rules for derivatives require marking these instruments to fair value at the balance sheet reporting date. The Company follows mark-to-market accounting and recognizes all gains and losses on such instruments in earnings in the period in which they occur. As a result, changes in the fair value of QEP's commodity derivative instruments could have a significant impact on net income. QEP does not engage in speculative hedging transactions, nor does it buy and sell energy contracts with the objective of generating profits on short-term differences in price. Refer to Note 6 – Derivative Contracts, in Item 8 of Part II of this Annual Report on Form 10-K for additional 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 on the Consolidated Statements of Operations.

QEP measures pension plan assets at fair value. Defined-benefit plan obligations and costs are actuarially determined, incorporating the use of various assumptions. Critical assumptions for pension and other postretirement benefit plans include the discount rate, the expected rate of return on plan assets (for funded pension plans) and the rate of future compensation increases. Other assumptions involve demographic factors such as retirement, mortality and turnover. QEP evaluates and updates its actuarial assumptions at least annually. QEP recognizes a pension curtailment immediately when there is a significant reduction in, or an elimination of, defined-benefit accruals for present employees' future services. Refer to Note 11 – Employee Benefits, in Item 8 of Part II of this Annual Report on Form 10-K for additional information.

Share-Based Compensation
QEP issues stock options, restricted share awards and restricted share units to certain officers, employees and non-employee directors under its Long-Term Stock Incentive Plan (LTSIP). QEP uses the Black-Scholes-Merton mathematical model to estimate the fair value of stock options for accounting purposes. The grant date fair value for restricted share awards is determined based on the closing bid price of the Company's common stock on the grant date. Share-based compensation cost for restricted share units is equal to its fair value as of the end of the period and is classified as a liability. QEP uses an accelerated method in recognizing share-based compensation costs for stock options and restricted share awards with graded-vesting periods. Stock options held by employees generally vest in three equal, annual installments and primarily have a term of seven years. Restricted share awards and restricted share units vest in equal installments over a specified number of years after the grant date with the majority vesting in three years. Non-vested restricted share awards have voting and dividend rights; however, sale or transfer is restricted. Employees may elect to defer their grants of restricted share awards and these deferred awards are designated as restricted share units. Restricted share units vest over a three-year period and are deferred into the Company's nonqualified unfunded deferred compensation plan at the time of vesting. The Company also awards performance share units under its Cash Incentive Plan (CIP) that are generally paid out in cash depending upon the Company's total shareholder return compared to a group of its peers over a three-year period. Share-based compensation cost for the performance share units is equal to its fair value as of the end of the period and is classified as a liability. Refer to Note 10 – Share-Based Compensation, in Item 8 of Part II of this Annual Report on Form 10-K for additional 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. While we are still evaluating the full impact of the new tax legislation, we expect the substantial reduction of the federal corporate tax rate, from 35% to 21%, to benefit our financial results and cash flows in future periods. Refer to Note 12 – Income Taxes, in Item 8 of Part II of this Annual Report on Form 10-K for additional information.

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

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

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in higher DD&A expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value, or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded. Refer to Note 2 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K for additional information regarding purchase price allocations.

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk Management

QEP uses commodity derivative instruments in the normal course of business to reduce the risk of adverse commodity price movements. However, these arrangements typically limit future gains from favorable price movements. The types of commodity derivative instruments currently utilized by the Company are fixed-price and basis swaps and collars. The volume of commodity derivative instruments utilized by the Company may vary from year to year based on QEP's forecasted production. The Company's current derivative instruments do not have margin requirements or collateral provisions that would require payments prior to the scheduled cash settlement dates. As of December 31, 2017, QEP held commodity price derivative contracts totaling 24.8 million barrels of oil, 147.8 million MMBtu of gas and 0.6 million MMBtu of net gas storage. As of December 31, 2016, QEP held commodity price derivative contracts totaling 20.8 million barrels of oil, 200.9 million MMBtu of gas and 4.0 million MMBtu of net gas storage.

The following table presents QEP's volumes and average prices for its derivative positions as of February 23, 2018. Refer to Note 6 – Derivative Contracts, in Item 8 of Part II of this Annual Report on Form 10-K for open derivative positions as of December 31, 2017.

Production Commodity Derivative Swaps

Year	Index	Total Volumes		Average Swap Price per Unit
		(in millions)		
Oil sales		(bbls)		($/bbl)
2018	NYMEX WTI	15.4	$	52.48
2019	NYMEX WTI	9.1	$	52.45
Gas sales		(MMBtu)		($/MMBtu)
2018 (Full Year)	NYMEX HH	91.8	$	2.99
2018 (July through December)	NYMEX HH	1.8	$	3.01
2019	NYMEX HH	43.8	$	2.86

Production Commodity Derivative Basis Swaps

Year	Index Less Differential	Index	Total Volumes		Weighted-Average Differential
			(in millions)		
Oil sales			(bbls)		($/bbl)
2018 (Full Year)	NYMEX WTI	Argus WTI Midland	6.7	$	(1.06)
2018 (July through December)	NYMEX WTI	Argus WTI Midland	0.9	$	(0.71)
2019	NYMEX WTI	Argus WTI Midland	4.7	$	(0.77)
Gas sales			(MMBtu)		($/MMBtu)
2018	NYMEX HH	IFNPCR	6.1	$	(0.16)

Changes in the fair value of derivative contracts from December 31, 2016 to December 31, 2017, are presented below:

	Commodity derivative contracts
	(in millions)
Net fair value of oil and gas derivative contracts outstanding at December 31, 2016	$ (201.8)
Contracts settled	**15.5**
Change in oil and gas prices on futures markets	**150.5**
Contracts added	**(96.1)**
Net fair value of oil and gas derivative contracts outstanding at December 31, 2017	**$ (131.9)**

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, 2017
	(in millions)
Net fair value – asset (liability)	**$ (131.9)**
Fair value if market prices of oil, gas and basis differentials decline by 10%	**$ (118.6)**
Fair value if market prices of oil, gas and basis differentials increase by 10%	**$ (145.0)**

Utilizing the actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these instruments by $13.1 million, while a 10% decrease in underlying commodity prices would increase the fair value of these instruments by $13.3 million as of December 31, 2017. However, a gain or loss eventually would be substantially offset by the actual sales value of the physical production covered by the derivative instruments. For additional information regarding the Company's commodity derivative transactions, refer to Note 6 – 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, 2017, QEP had $89.0 million outstanding under the credit facility. As of December 31, 2016, QEP had no borrowings outstanding under the credit facility. If interest rates were to increase or decrease 10% during the year ended December 31, 2017, at our average level of borrowing for those same periods, the Company's interest expense would increase or decrease by $0.1 million for the year ended December 31, 2017, or less than 1% of total interest expense.

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

Report of Independent Registered Public Accounting Firm

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

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of QEP Resources, Inc. and its subsidiaries as of December 31, 2017 and 2016, 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, 2017, 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, 2017, 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, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 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, 2017, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Assessment of Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

/s/ PricewaterhouseCoopers LLP
Denver, Colorado
February 28, 2018

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

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2017	2016	2015
REVENUES	(in millions, except per share amounts)		
Oil sales	**$ 939.4**	$ 769.1	$ 834.2
Gas sales	**494.0**	417.1	468.5
NGL sales	**111.9**	83.5	80.0
Other revenues	**15.0**	6.2	15.1
Purchased oil and gas sales	**62.6**	101.2	620.8
Total Revenues	**1,622.9**	1,377.1	2,018.6
OPERATING EXPENSES			
Purchased oil and gas expense	**64.3**	105.5	626.8
Lease operating expense	**294.8**	224.7	238.8
Transportation and processing costs	**245.3**	289.2	291.3
Gathering and other expense	**7.3**	5.0	5.8
General and administrative	**153.5**	196.5	168.0
Production and property taxes	**114.3**	94.8	117.6
Depreciation, depletion and amortization	**754.5**	871.1	881.1
Exploration expenses	**22.0**	1.7	2.7
Impairment	**78.9**	1,194.3	55.6
Total Operating Expenses	**1,734.9**	2,982.8	2,387.7
Net gain (loss) from asset sales	**213.5**	5.0	4.6
OPERATING INCOME (LOSS)	**101.5**	(1,600.7)	(364.5)
Realized and unrealized gains (losses) on derivative contracts (Note 6)	**24.5**	(233.0)	277.2
Interest and other income (expense)	**1.6**	23.7	(10.1)
Loss from early extinguishment of debt	**(32.7)**	—	—
Interest expense	**(137.8)**	(143.2)	(145.6)
INCOME (LOSS) BEFORE INCOME TAXES	**(42.9)**	(1,953.2)	(243.0)
Income tax (provision) benefit	**312.2**	708.2	93.6
NET INCOME (LOSS)	**$ 269.3**	$ (1,245.0)	$ (149.4)
Earnings (loss) per common share			
Basic	**$ 1.12**	$ (5.62)	$ (0.85)
Diluted	**$ 1.12**	$ (5.62)	$ (0.85)
Weighted-average common shares outstanding			
Used in basic calculation	**240.6**	221.7	176.6
Used in diluted calculation	**240.6**	221.7	176.6
Dividends per common share	**$ —**	$ —	$ 0.08

Refer to Notes accompanying the Consolidated Financial Statements.

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

	Year Ended December 31,		
	2017	2016	2015
		(in millions)	
Net income (loss)	**$ 269.3**	$ (1,245.0)	$ (149.4)
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]	**2.4**	—	(0.6)
Current period net actuarial (gain) loss[3]	**5.8**	(5.6)	(0.5)
Amortization of prior service cost[4]	**0.5**	0.8	8.2
Amortization of net actuarial (gain) loss[5]	**0.3**	0.5	0.3
Net curtailment and settlement cost incurred[6]	**0.4**	—	4.5
Other comprehensive income (loss)	**5.6**	(4.3)	11.9
Comprehensive income (loss)	**$ 274.9**	$ (1,249.3)	$ (137.5)

(1) The new 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 using the lower rate.

(2) Presented net of income tax expense of $0.8 million for the year ended December 31, 2017 and net of income tax benefit of $0.3 million for the year ended December 31, 2015.

(3) Presented net of income tax expense of $1.8 million for the year ended December 31, 2017 and net of income tax benefit of $3.3 million and $0.3 million for the years ended December 31, 2016 and 2015, respectively.

(4) Presented net of income tax expense of $0.2 million, $0.5 million, and $4.9 million for the years ended December 31, 2017, 2016, and 2015, respectively.

(5) Presented net of income tax expense of $0.1 million, $0.3 million, and $0.2 million for the years ended December 31, 2017, 2016, and 2015, respectively.

(6) Presented net of income tax expense of $0.1 million and $2.6 million for the years ended December 31, 2017 and 2015, respectively.

Refer to Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2017	December 31, 2016
ASSETS	(in millions)	
Current Assets		
Cash and cash equivalents	**$ —**	$ 443.8
Accounts receivable, net	**142.1**	155.7
Income tax receivable	**4.9**	18.6
Fair value of derivative contracts	**3.4**	—
Hydrocarbon inventories, at lower of average cost or net realizable value	**3.6**	10.4
Prepaid expenses	**10.7**	11.4
Other current assets	**0.7**	0.2
Total Current Assets	**165.4**	640.1
Property, Plant and Equipment (successful efforts method for oil and gas properties)		
Proved properties	**12,470.9**	14,232.5
Unproved properties	**1,095.8**	871.5
Gathering and other	**319.7**	301.8
Materials and supplies	**37.8**	32.7
Total Property, Plant and Equipment	**13,924.2**	15,438.5
Less Accumulated Depreciation, Depletion and Amortization		
Exploration and production	**6,642.9**	8,797.7
Gathering and other	**124.3**	101.8
Total Accumulated Depreciation, Depletion and Amortization	**6,767.2**	8,899.5
Net Property, Plant and Equipment	**7,157.0**	6,539.0
Fair value of derivative contracts	**0.1**	—
Other noncurrent assets	**72.3**	66.3
TOTAL ASSETS	**$ 7,394.8**	$ 7,245.4
LIABILITIES AND EQUITY		
Current Liabilities		
Checks outstanding in excess of cash balances	**$ 44.0**	$ 12.3
Accounts payable and accrued expenses	**372.1**	269.7
Production and property taxes	**31.6**	30.1
Interest payable	**26.0**	32.9
Fair value of derivative contracts	**103.6**	169.8
Total Current Liabilities	**577.3**	514.8
Long-term debt	**2,160.8**	2,020.9
Deferred income taxes	**518.0**	825.9
Asset retirement obligations	**206.6**	225.8
Fair value of derivative contracts	**31.8**	32.0
Other long-term liabilities	**102.4**	123.3
Commitments and Contingencies (Note 9)		
EQUITY		
Common stock - par value $0.01 per share; 500.0 million shares authorized; 243.0 million and 240.7 million shares issued, respectively	**2.4**	2.4
Treasury stock - 2.0 million and 1.1 million shares, respectively	**(34.2)**	(22.9)
Additional paid-in capital	**1,398.2**	1,366.6
Retained earnings	**2,442.6**	2,173.3
Accumulated other comprehensive income (loss)	**(11.1)**	(16.7)
Total Common Shareholders' Equity	**3,797.9**	3,502.7
TOTAL LIABILITIES AND EQUITY	**$ 7,394.8**	$ 7,245.4

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, 2014	176.2	$ 1.8	(0.8)	$ (25.4)	$ 535.3	$ 3,587.9	$ (24.3)	$ 4,075.3
Net income (loss)	—	—	—	—	—	(149.4)	—	(149.4)
Dividends paid	—	—	—	—	—	(14.1)	—	(14.1)
Share-based compensation	1.1	—	0.3	10.8	19.5	(6.1)	—	24.2
Change in pension and postretirement liability, net of tax	—	—	—	—	—	—	11.9	11.9
Balance at December 31, 2015	177.3	1.8	(0.5)	(14.6)	554.8	3,418.3	(12.4)	3,947.9
Net income (loss)	—	—	—	—	—	(1,245.0)	—	(1,245.0)
Equity issuance, net of offering costs	61.0	0.6	—	—	780.8	—	—	781.4
Share-based compensation	2.4	—	(0.6)	(8.3)	31.0	—	—	22.7
Change in pension and postretirement liability, net of tax	—	—	—	—	—	—	(4.3)	(4.3)
Balance at December 31, 2016	240.7	2.4	(1.1)	(22.9)	1,366.6	2,173.3	(16.7)	3,502.7
Net income (loss)	**—**	**—**	**—**	**—**	**—**	**269.3**	**—**	**269.3**
Share-based compensation	**2.3**	**—**	**(0.9)**	**(11.3)**	**31.6**	**—**	**—**	**20.3**
Change in pension and postretirement liability, net of tax	**—**	**—**	**—**	**—**	**—**	**—**	**5.6**	**5.6**
Balance at December 31, 2017	**243.0**	**$ 2.4**	**(2.0)**	**$ (34.2)**	**$ 1,398.2**	**$ 2,442.6**	**$ (11.1)**	**$ 3,797.9**

Refer to Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2017	2016	2015
OPERATING ACTIVITIES		**(in millions)**	
Net income (loss)	**$ 269.3**	$ (1,245.0)	$ (149.4)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	**754.5**	871.1	881.1
Deferred income taxes	**(314.8)**	(651.3)	25.3
Impairment	**78.9**	1,194.3	55.6
Dry hole exploratory well expense	**21.3**	—	—
Share-based compensation	**22.4**	35.6	34.7
Pension curtailment loss	**—**	—	11.2
Amortization of debt issuance costs and discounts	**6.2**	6.4	6.2
Bargain purchase gain from acquisitions	**0.4**	(22.6)	—
Net (gain) loss from asset sales	**(213.5)**	(5.0)	(4.6)
Loss from early extinguishment of debt	**32.7**	—	—
Unrealized (gains) losses on marketable securities	**(2.9)**	(1.4)	0.2
Unrealized (gains) losses on derivative contracts	**(40.0)**	367.0	183.7
Other non-cash activity	**(9.4)**	—	—
Changes in operating assets and liabilities			
Accounts receivable	**(2.0)**	95.3	124.6
Hydrocarbon inventories	**(1.1)**	8.7	15.5
Prepaid expenses	**(0.2)**	18.5	16.7
Accounts payable and accrued expenses	**3.5**	(50.3)	(34.5)
Federal income taxes receivable	**13.7**	68.7	(619.4)
Other	**(20.6)**	(26.3)	(65.6)
Net Cash Provided by (Used in) Operating Activities	**598.4**	663.7	481.3
INVESTING ACTIVITIES			
Property acquisitions	**(815.2)**	(639.0)	(98.3)
Property, plant and equipment, including exploratory well expense	**(1,159.6)**	(569.1)	(1,141.1)
Proceeds from disposition of assets	**806.8**	29.0	21.8
Net Cash Provided by (Used in) Investing Activities	**(1,168.0)**	(1,179.1)	(1,217.6)
FINANCING ACTIVITIES			
Checks outstanding in excess of cash balances	**31.7**	(17.5)	(24.9)
Long-term debt issued	**500.0**	—	—
Long-term debt issuance costs paid	**(14.4)**	—	(2.6)
Long-term debt extinguishment costs paid	**(28.1)**	—	—
Long-term debt repaid	**(445.6)**	(176.8)	—
Proceeds from credit facility	**492.0**	—	—
Repayments of credit facility	**(403.0)**	—	—
Treasury stock repurchases	**(6.8)**	(4.1)	(2.7)
Other capital contributions	**—**	—	(0.2)
Dividends paid	**—**	—	(14.1)
Proceeds from issuance of common stock, net	**—**	781.4	—
Excess tax (provision) benefit on share-based compensation	**—**	0.1	(3.2)
Net Cash Provided by (Used in) Financing Activities	**125.8**	583.1	(47.7)
Change in cash and cash equivalents	**(443.8)**	67.7	(784.0)
Beginning cash and cash equivalents	**443.8**	376.1	1,160.1
Ending cash and cash equivalents	**$ —**	$ 443.8	$ 376.1

Refer to Notes accompanying the Consolidated Financial Statements.

Note 1 – Summary of Significant Accounting Policies

Nature of Business

QEP Resources, Inc. is an independent crude oil and natural gas exploration and production company with operations in two regions of the United States: the Northern Region (primarily in North Dakota and Utah) and the Southern Region (primarily in Texas and Louisiana). 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 Regulations 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.

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. As a result, QEP Energy directly markets its own oil, gas and NGL production. While QEP continues to act as an agent for the sale of oil, 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.

Reclassifications

Certain prior period amounts on the Consolidated Statements of Operations, Consolidated Balance Sheets and 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, cash flows, current assets 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, 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, 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 gas production. Refer to Note 6 – Derivative Contracts for the Company's open oil and gas commodity derivative contracts.

Revenue Recognition

QEP recognizes revenue from oil and gas producing activities in the period that services are provided or products are delivered. Revenues associated with the sale of oil, gas and NGL are accounted for using the sales method, whereby revenue is recognized when these commodities are sold to purchasers. Revenues include estimates for the two most recent months using published commodity price indexes and volumes supplied by field operators. An imbalance liability is recorded to the extent that QEP has sold volumes in excess of its share of remaining reserves in an underlying property.

QEP also purchases and resells oil and gas primarily to mitigate losses on unutilized capacity related to firm transportation commitments and storage activities. QEP recognizes revenue from these resale activities when title transfers to the customer.

Cash and 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.

As of December 31, 2017, QEP had no unrestricted cash and restricted cash of $23.4 million. As of December 31, 2016, QEP had unrestricted cash of $443.8 million and restricted cash of $21.6 million. QEP's restricted cash is primarily cash deposited into an escrow account related to a title dispute between third parties in the Williston Basin and is included in "Other noncurrent assets" on the Consolidated Balance Sheets.

Supplemental cash flow information is shown in the table below:

	Year Ended December 31,		
	2017	2016	2015
Supplemental Disclosures		(in millions)	
Cash paid for interest, net of capitalized interest	**$ 134.9**	$ 139.1	$ 139.4
Cash paid (refund received) for income taxes, net	**$ (0.3)**	$ (123.5)	$ 487.8
Non-cash investing activities			
Change in capital expenditure accrual balance	**$ 60.2**	$ (32.8)	$ (129.2)

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. Recovery of bad debt associated with accounts receivable for the year ended December 31, 2017 was $1.0 million. Bad debt expense associated with accounts receivable for the years ended December 31, 2016 and 2015, was $1.8 million, and $0.5 million, respectively. Bad debt recovery or expense 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, 2017, and $4.8 million at December 31, 2016.

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.

Capitalized Exploratory Well Costs
The Company capitalizes exploratory well costs until it determines whether an exploratory well is commercial or noncommercial. If the Company deems the well commercial, capitalized costs are depreciated on a field basis using the unit-of-production method and the estimated proved developed oil and gas reserves. If the Company concludes that the well is noncommercial, well costs are immediately charged to exploration expense. Exploratory well costs that have been capitalized for a period greater than one year since the completion of drilling are expensed unless the Company remains engaged in substantial activities to assess whether the project is commercial.

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 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, gas and NGL reserves caused by mechanical problems, faster-than-expected decline of production, lease ownership issues, and declines in oil, gas and NGL prices. If impairment is indicated, fair value is estimated using a discounted cash flow approach. Cash flow estimates require forecasts and assumptions for many years into the future for a variety of factors, including commodity prices, operating costs and estimates of proved, probable and possible reserves. 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, 2017, QEP recorded impairment charges of $78.9 million, of which $38.1 million 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 3 – Capitalized Exploratory Well Costs for additional information), $6.5 million was related to impairment of an underground gas storage facility and $5.3 million was related to the impairment of goodwill. Of the $38.1 million impairment of proved properties, $37.1 million related to the Other Northern area and $1.0 million related to Louisiana properties.

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

During the year ended December 31, 2015, QEP recorded impairment charges of $55.6 million, of which $39.3 million was related to proved properties due to lower future oil and gas prices, $2.0 million was related to expiring leaseholds on unproved properties and $14.3 million was related to the impairment of goodwill. Of the $39.3 million impairment on proved properties, $20.2 million related to QEP's remaining Other Southern properties, $18.4 million related Other Northern properties, and $0.7 million related to Permian Basin properties.

Asset Retirement Obligations
QEP is obligated to fund the costs of disposing of long-lived assets upon their abandonment. The Company's ARO liability applies primarily to abandonment costs associated with oil and gas wells and certain other properties. ARO associated with the retirement of tangible long-lived assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived assets in the period incurred. The cost of the tangible asset, including the asset retirement costs, is depreciated over the useful life of the asset. ARO are recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligations discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value. If estimated future costs of ARO change, an adjustment is recorded to both the ARO liability and the long-lived asset. Revisions to estimated ARO can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment. Refer to Note 4 – Asset Retirement Obligations for additional 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. During the year ended December 31, 2017, QEP early adopted ASU 2017-04, *Intangibles – Goodwill and Other (Topic 350): Simplifying the test for goodwill impairment*. Under the new guidance 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, 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, which related to an acquisition in the first quarter of 2017. During the fourth quarter of 2017, QEP performed an annual impairment test over goodwill as described above, which resulted in a full write down of goodwill of $5.3 million.

During the years ended December 31, 2016 and 2015, QEP recorded $3.7 million and $14.3 million, respectively, of goodwill. Annual impairment tests over goodwill at year end December 31, 2016 and 2015 resulted in a full write down of $3.7 million and $14.3 million, respectively.

Litigation and Other Contingencies

The Company is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business. In each reporting period, the Company assesses these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in its Consolidated Financial Statements. The amount of ultimate loss may differ from these estimates. In accordance with ASC 450, *Contingencies*, an accrual is recorded for a material loss contingency when its occurrence is probable and damages are reasonably estimable based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes. Refer to Note 9 – Commitments and Contingencies for additional 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 additional information becomes available or as circumstances change. Future environmental expenditures are not discounted to their present value. Recoveries of environmental costs from other parties are recorded separately as assets at their undiscounted value when receipt of such recoveries is probable.

Derivative Contracts

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

These derivative contracts are recorded in "Realized and unrealized gains (losses) on derivative contracts" on the Consolidated Statements of Operations in the month of settlement and are also marked-to-market monthly. Refer to Note 6 – Derivative Contracts for additional 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, and 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 may be 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 59%, 48%, and 30% of QEP's revenues for the years ended December 31, 2017, 2016 and 2015, respectively. During the year ended December 31, 2017, Shell Trading Company, Occidental Energy Marketing, Andeavor Logistics LP, BP Energy Company and Plains Marketing LP accounted for 14%, 13%, 13%, 10% and 10%, respectively, of QEP's total revenues. During the year ended December 31, 2016, Shell Trading Company, BP Energy Company and Valero Marketing & Supply Company accounted for 14%, 10% and 10%, respectively, of QEP's total revenues. During the year ended December 31, 2015, no customer 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.

Income Taxes

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

ASC 740, *Income Taxes,* specifies the accounting for uncertainty in income taxes by prescribing a minimum recognition threshold for a tax position to be reflected in the financial statements. If recognized, the tax benefit is measured as the largest amount of tax benefit that is more-likely-than-not to be realized upon ultimate settlement. Management has considered the amounts and the probabilities of the outcomes that could be realized upon ultimate settlement and believes that it is more-likely-than-not that the Company's recorded income tax benefits will be fully realized, except as noted below. As of December 31, 2017, the Company had a valuation allowance of $56.8 million against the state net operating loss deferred tax asset because management does not forecast future income in Oklahoma and Louisiana to offset net operating losses before they expire. All federal income tax returns prior to 2017 have been examined by the Internal Revenue Service and are closed. Income tax returns for 2017 have not yet been filed. Most state tax returns for 2014 and subsequent years remain subject to examination.

The benefits of uncertain tax positions taken or expected to be taken on income tax returns is recognized in the consolidated financial statements at the largest amount that is more-likely-than-not to be sustained upon examination by the relevant taxing authorities. Our policy is to recognize any interest earned on income tax refunds in "Interest and other income (expense)" on the Consolidated Statements of Operations, any interest expense related to uncertain tax positions in "Interest expense" on the Consolidated Statements of Operations and to recognize any penalties related to uncertain tax positions in "General and administrative" expense on the Consolidated Statements of Operations. As of December 31, 2017 and 2016, QEP had $19.0 million and $15.6 million of unrecognized tax benefits related to uncertain tax positions for asset sales that occurred in 2014, which was included within "Other long-term liabilities" on the Consolidated Balance Sheets. During the year ended December 31, 2017, the Company incurred $0.7 million of estimated interest expense related to uncertain tax positions. During the year ended December 31, 2016, the Company incurred $0.7 million of estimated interest expense and $0.6 million of estimated penalties related to uncertain tax positions. During the year ended December 31, 2015, the Company incurred $0.5 million of estimated interest expense and $2.2 million of estimated penalties related to uncertain tax positions.

On December 22, 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 Tax Legislation also repeals the corporate alternative minimum tax (AMT). Several provisions of the new tax law such as limitations on the deductibility of interest expense and certain executive compensation and the inability to use Section 1031 like-kind exchanges for assets such as machinery and equipment could apply to QEP; however, we do not believe that they will materially impact QEP's financial statements. 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. The Company will continue to analyze the Tax Legislation to determine the full impact of the new law, 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 10 – Share-Based Compensation for additional 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, 2017 and 2015, there were no anti-dilutive shares. For the year ended December 31, 2016, there were 0.1 million shares not included in diluted common shares outstanding as they were anti-dilutive due to QEP's net loss from continuing operations.

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

	December 31,		
	2017	2016	2015
		(in millions)	
Weighted-average basic common shares outstanding	**240.6**	221.7	176.6
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	**240.6**	221.7	176.6

Share-Based Compensation

QEP issues stock options, restricted share awards and restricted share units to certain officers, employees and non-employee directors under its Long-Term Stock Incentive Plan (LTSIP). QEP uses the Black-Scholes-Merton mathematical model to estimate the fair value of stock options for accounting purposes. The grant date fair value for restricted share awards is determined based on the closing bid price of the Company's common stock on the grant date. Share-based compensation cost for restricted share units is equal to its fair value as of the end of the period and is classified as a liability. QEP uses an accelerated method in recognizing share-based compensation costs for stock options and restricted share awards with graded-vesting periods. Stock options held by employees generally vest in three equal, annual installments and primarily have a term of seven years. Restricted share awards and restricted share units vest in equal installments over a specified number of years after the grant date with the majority vesting in three years. Non-vested restricted share awards have voting and dividend rights; however, sale or transfer is restricted. Employees may elect to defer their grants of restricted share awards and these deferred awards are designated as restricted share units. Restricted share units vest over a three-year period and are deferred into the Company's nonqualified unfunded deferred compensation plan at the time of vesting. The Company also awards performance share units under its 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. For additional information, refer to Note 10 – Share-Based Compensation for additional 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 11 – Employee Benefits for additional 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. Other comprehensive income (loss) includes certain items that are recorded directly to equity and classified as accumulated other comprehensive income (AOCI), which includes changes in the underfunded portion of the Company's defined-benefit pension and other postretirement benefits plans and changes in deferred income taxes on such amounts. These transactions do not represent the culmination of the earnings process but result from periodically adjusting historical balances to fair value.

Recent Accounting Developments

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers (Topic 606)*, which seeks to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries and across capital markets. The revenue standard contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. In addition, new and enhanced disclosures will be required. The amendment is effective prospectively for reporting periods beginning on or after December 15, 2017, and early adoption is permitted for periods beginning on or after December 15, 2016. The two permitted transition methods under the new standard are the full retrospective method, in which case the standard would be applied to each prior reporting period presented, or the modified retrospective method, in which case the cumulative effect of applying the standard would be recognized at the date of initial application. The Company does not expect net income (loss) or cash flows to be materially impacted by the new standard; however, the Company expects that a portion of its transportation and processing costs will be netted within revenue under the new standard. In addition, the Company will have expanded disclosure requirements, as a result of the adoption of the ASU. The Company has selected the modified retrospective method and will adopt this guidance on the effective date of January 1, 2018.

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)*, which requires lessees to recognize the lease assets and lease liabilities classified as operating leases on the balance sheet and disclose key quantitative and qualitative information about leasing arrangements. The amendment will be effective for reporting periods beginning after December 15, 2018, and early adoption is permitted. The Company is currently assessing the impact of the ASU on the Company's Consolidated Financial Statements.

In March 2016, the FASB issued ASU No. 2016-06, *Derivatives and hedging (Topic 815): Contingent put and call options in debt instruments*, which clarifies the requirements for assessing whether contingent call (put) options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. The amendment was effective prospectively for reporting periods beginning on or after December 15, 2016, and early adoption was permitted. The Company adopted this standard in the first quarter of 2017 and the adoption of this new standard did not have a material impact on the Company's Consolidated Financial Statements.

In March 2016, the FASB issued ASU No. 2016-09, *Compensation – Stock Compensation (Topic 718): Improvements to employee share-based payment accounting,* which includes provisions intended to simplify various aspects related to how share-based compensation payments are accounted for and presented in the financial statements. This amendment was effective prospectively for reporting periods beginning after December 15, 2016, and early adoption was permitted. The Company adopted this standard in the first quarter of 2017 and the adoption of this new standard did not have a material impact on the Company's Consolidated Financial Statements.

In August 2016, the FASB issued ASU No. 2016-15, *Statement of Cash Flows (Topic 230): Classification of certain cash receipts and cash payments* , which intends to reduce the diversity in practice in how certain transactions are classified in the statement of cash flows. This amendment will be effective retrospectively for reporting periods beginning after December 15, 2017, and early adoption is permitted. The Company early adopted this standard in the fourth quarter of 2017 and the adoption of this standard did not have a material impact on the Company's Consolidated Financial Statements.

In January 2017, the FASB issued ASU No. 2017-01, *Business Combinations (Topic 805): Clarifying the definition of a business*, which clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of businesses. The amendment will be effective prospectively for reporting periods beginning after December 15, 2017, and early adoption is permitted. The Company early adopted this standard in the fourth quarter of 2017 and the adoption of this standard did not have a material impact on the Company's Consolidated Financial Statements; however, this standard may impact the determination of whether future acquisitions are accounted for as a business combination or an asset acquisition.

In January 2017, the FASB issued ASU No. 2017-04, *Intangibles – Goodwill and Other (Topic 350): Simplifying the test for goodwill impairment*, which eliminates the requirement to calculate implied fair value of goodwill to measure the goodwill impairment charge. The amendment will be effective prospectively for reporting periods beginning after December 15, 2019, and early adoption is permitted. The Company early adopted this standard in the first quarter of 2017 and the adoption of this new standard did not have a material impact on the Company's Consolidated Financial Statements.

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the presentation of net periodic pension cost and net periodic postretirement benefit cost*, which changes how employers of a defined benefit plan present net periodic benefit cost in the statements of operations. The amendment will be effective retrospectively for reporting periods beginning after December 15, 2017, and early adoption is permitted. The Company early adopted this standard in the first quarter of 2017 and recast the years ended December 31, 2016 and 2015. The adoption of this new standard did not have a material impact on the Company's Consolidated Financial Statements. Refer to Note 11 – Employee Benefits for additional information regarding the Company's pension and other postretirement plans.

Note 2 – Acquisitions and Divestitures

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 $720.7 million, subject to post-closing purchase price adjustments (the 2017 Permian Basin Acquisition). The 2017 Permian Basin Acquisition consists of approximately 15,100 acres, mainly in Martin County, Texas, which are held by production from existing vertical wells. QEP structured the transaction as a like-kind exchange under Section 1031 of the Internal Revenue Service Code and funded the purchase price with the proceeds from the Pinedale Divestiture. In accordance with the early adoption of ASU No. 2017-01, *Business Combinations (Topic 805): Clarifying the definition of a business* in the fourth quarter of 2017*,* 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. In addition, QEP has made offers to various persons who own additional oil and gas interests in certain properties included in the 2017 Permian Basin Acquisition on substantially the same terms and conditions as the original purchase. If all offers are accepted, the aggregate purchase price is not expected to exceed $50.0 million.

2016 Permian Basin Acquisition

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

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

The following table presents a summary of the Company's purchase accounting entries (in millions) as of December 31, 2017:

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

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

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

Other Acquisitions

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

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

During the year ended December 31, 2015, QEP acquired various oil and gas properties, primarily in the Williston and Permian basins, for a total purchase price of $98.3 million, which included acquisitions of additional interests in QEP operated wells and additional undeveloped leasehold acreage. In conjunction with the acquisitions, the Company recorded $14.3 million of goodwill, which was subsequently impaired.

Pinedale Divestiture

In September 2017, QEP sold its Pinedale assets (the Pinedale Divestiture), for net cash proceeds (after purchase price adjustments) of $718.2 million, subject to post-closing purchase price adjustments, and recorded a pre-tax gain on sale of $180.4 million which was recorded within "Net gain (loss) from asset sales" on the Consolidated Statements of Operations. As part of the purchase and sale agreement, at the request of the buyer, QEP agreed to enter into derivative contracts covering a portion of Pinedale's future production. Those derivative contracts were novated to the buyer at closing. In addition, QEP agreed to reimburse the buyer for certain deficiency charges it incurs related to gas processing and NGL transportation and fractionation contracts, if any, between the effective date of the sale and December 31, 2019, in an aggregate amount not to exceed $45.0 million. The fair value of the deficiency charges was measured utilizing an internally developed cash flow model discounted at QEP's weighted average cost of debt. Given the unobservable nature of the inputs, the fair value calculation associated with the deficiency charges is considered Level 3 within the fair value hierarchy. As of December 31, 2017, the liability associated with estimated future payments for this commitment was $30.6 million, of which $27.4 million is reported on the Consolidated Balance Sheets within "Accounts payable and accrued expenses" and $3.2 million is reported on the Consolidated Balance Sheets within "Other long-term liabilities".

QEP accounted for revenues and expenses related to Pinedale, including the pre-tax gain on sale of $180.4 million, during the years ended December 31, 2017, 2016 and 2015, as income on the Consolidated Statements of Operations because the sale of the Pinedale assets did not cause a strategic shift for the Company and as a result, did not qualify as discontinued operations under ASU 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*. The Pinedale Divestiture did, however, represent the sale of an individually significant component. For the year ended December 31, 2017, QEP recorded net income before income taxes related to Pinedale, prior to the divestiture, of $251.0 million, which includes the pre-tax gain on sale of $180.4 million. For the year ended December 31, 2016, QEP recorded a net loss before income taxes of $1,152.7 million. The net loss before income taxes was primarily due to an impairment on proved properties of $1,164.0 million recognized in 2016 as a result of a decrease in expected future gas prices. For the year ended December 31, 2015, QEP recorded net loss before income taxes of $45.6 million related to Pinedale.

Other Divestitures

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 3 – Capitalized Exploratory Well Costs for more information. In addition, QEP received net cash proceeds of $85.1 million and recorded a pre-tax gain on sale of $33.1 million, primarily related to the sale of properties in the Other Northern area.

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

During the year ended December 31, 2015, QEP sold its interest in certain non-core properties in the Other Southern area for aggregate proceeds of $31.7 million, of which $21.8 million was cash and $9.9 million of accounts receivable and recorded a pre-tax gain on sale of $21.0 million. During the year ended December 31, 2016, QEP recorded a pre-tax loss of sale of $0.9 million, due to post-closing purchase price adjustments from the sale of such properties.

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

Note 3 – Capitalized Exploratory Well Costs

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

	Capitalized Exploratory Well Costs		
	2017	2016	2015
		(in millions)	
Balance at January 1,	**$ 14.2**	$ 2.6	$ 12.6
Additions to capitalized exploratory well costs	**10.7**	11.7	6.0
Reclassifications to proved properties	**(3.6)**	—	(16.0)
Capitalized exploratory well costs charged to expense	**(21.3)**	(0.1)	—
Balance at December 31,	**$ —**	$ 14.2	$ 2.6

The balance at December 31, 2016 and 2015 represents the amount of capitalized exploratory well costs that are pending the determination of proved reserves.

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

Note 4 – 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. Of the $214.1 million and $231.6 million ARO liability as of December 31, 2017 and 2016, respectively, $7.5 million and $5.8 million, respectively, was included as a liability in "Accounts payable and accrued expenses" on the Consolidated Balance Sheets.

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

	Asset Retirement Obligations	
	2017	2016
	(in millions)	
ARO liability at January 1,	**$ 231.6**	$ 206.8
Accretion	**7.7**	8.9
Additions[1]	**23.5**	17.0
Revisions	**8.5**	6.5
Liabilities related to assets sold[2]	**(34.9)**	—
Liabilities settled	**(22.3)**	(7.6)
ARO liability at December 31,	**$ 214.1**	$ 231.6

(1) Additions for the year ended December 31, 2017, include $14.2 million related to the 2017 Permian Basin Acquisition and additions for the year ended December 31, 2016, include $11.6 million related to the 2016 Permian Basin Acquisition (refer to Note 2 – Acquisitions and Divestitures for more information).

(2) Liabilities related to assets sold for the year ended December 31, 2017, include $34.9 million related to the Pinedale Divestiture (refer to Note 2 – Acquisitions and Divestitures for more information).

Note 5 – 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 6 – Derivative Contracts for additional 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, 2017 and 2016, 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, 2017				
Financial Assets					
Fair value of derivative contracts – short-term	**$ —**	**$ 20.6**	**$ —**	**$ (17.2)**	**$ 3.4**
Fair value of derivative contracts – long-term	**—**	**2.3**	**—**	**(2.2)**	**0.1**
Total financial assets	**$ —**	**$ 22.9**	**$ —**	**$ (19.4)**	**$ 3.5**
Financial Liabilities					
Fair value of derivative contracts – short-term	**$ —**	**$ 120.8**	**$ —**	**$ (17.2)**	**$ 103.6**
Fair value of derivative contracts – long-term	**—**	**34.0**	**—**	**(2.2)**	**31.8**
Total financial liabilities	**$ —**	**$ 154.8**	**$ —**	**$ (19.4)**	**$ 135.4**
	December 31, 2016				
Financial Assets					
Fair value of derivative contracts – short-term	$ —	$ —	$ —	$ —	$ —
Fair value of derivative contracts – long-term	—	—	—	—	—
Total financial assets	$ —	$ —	$ —	$ —	$ —
Financial Liabilities					
Fair value of derivative contracts – short-term	$ —	$ 169.8	$ —	$ —	$ 169.8
Fair value of derivative contracts – long-term	—	32.0	—	—	32.0
Total financial liabilities	$ —	$ 201.8	$ —	$ —	$ 201.8

(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 6 – Derivative Contracts for additional information regarding the Company's derivative contracts.

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, 2017		December 31, 2016	
Financial Assets	(in millions)			
Cash and cash equivalents	**$ —**	**$ —**	$ 443.8	$ 443.8
Financial Liabilities				
Checks outstanding in excess of cash balances	**$ 44.0**	**$ 44.0**	$ 12.3	$ 12.3
Long-term debt	**$ 2,160.8**	**$ 2,256.2**	$ 2,020.9	$ 2,104.3

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 4 – 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 nonrecurring basis to review its proved oil and gas properties for potential impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such property. During the years ended December 31, 2017 and 2016, the Company recorded impairments of certain proved oil and gas properties of $38.1 million and $1,172.7 million, respectively, resulting in a reduction of the associated carrying value to fair value. The fair value of the property was measured utilizing the income approach and utilizing inputs which are primarily based upon internally developed cash flow models discounted at an appropriate weighted average cost of capital. 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. Refer to Note 1 – Summary of Significant Accounting Policies for additional information on impairment of oil and gas properties.

Acquisitions of proved and unproved properties are also measured at fair value on a nonrecurring basis. The Company utilizes a discounted cash flow model to estimate the fair value of acquired property as of the acquisition date which utilizes the following inputs to estimate future net cash flows: (i) estimated quantities of oil, gas and NGL reserves; (ii) estimates of future commodity prices; and (iii) estimated production rates, future operating and development costs, which are based on the Company's historic experience with similar properties. In some instances, market comparable information of recent transactions is used to estimate fair value of unproved acreage. Due to the unobservable characteristics of the inputs, the fair value of the acquired properties is considered Level 3 within the fair value hierarchy. Refer to Note 2 – Acquisitions and Divestitures for additional information on the fair value of acquired properties.

Note 6 – Derivative Contracts

QEP has established policies and procedures for managing commodity price volatility through the use of derivative instruments. In the normal course of business, QEP uses commodity price derivative instruments to reduce the impact of potential downward movements in commodity prices on cash flow, returns on capital investment, and other financial results. However, these instruments typically limit gains from favorable price movements. The volume of production subject to commodity derivative instruments and the mix of the instruments are frequently evaluated and adjusted by management in response to changing market conditions. QEP may enter into commodity derivative contracts for up to 100% of forecasted production, but generally, QEP enters into commodity derivative contracts for approximately 50% to 75% of its forecasted annual production by the end of the first quarter of each fiscal year. In addition, QEP may enter 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 or oil price swaps that use ICE Brent oil prices as the reference price. Gas price derivative instruments are typically structured as fixed-price swaps or costless collars at NYMEX Henry Hub or regional price indices. QEP also enters into oil and gas basis swaps to achieve a fixed-price swap for a portion of its oil and gas sales at prices that reference specific regional index prices.

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

Derivative Contracts – Production

The following table presents QEP's volumes and average prices for its commodity derivative swap contracts as of December 31, 2017:

Year	Index	Total Volumes		Average Swap Price per Unit
		(in millions)		
Oil sales		(bbls)		($/bbl)
2018	NYMEX WTI	16.8	$	52.48
2019	NYMEX WTI	8.0	$	51.78
Gas sales		(MMBtu)		($/MMBtu)
2018 (Full Year)	NYMEX HH	109.5	$	2.99
2018 (July through December)	NYMEX HH	1.8	$	3.01
2019	NYMEX HH	36.5	$	2.88

QEP uses oil and gas basis swaps, combined with NYMEX WTI and NYMEX HH 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 and gas basis swaps as of December 31, 2017:

Year	Index Less Differential	Index	Total Volumes		Weighted-Average Differential
			(in millions)		
Oil sales			(bbls)		($/bbl)
2018 (Full Year)	NYMEX WTI	Argus WTI Midland	7.3	$	(1.06)
2018 (July through December)	NYMEX WTI	Argus WTI Midland	0.9	$	(0.71)
2019	NYMEX WTI	Argus WTI Midland	4.0	$	(0.80)
Gas sales			(MMBtu)		($/MMBtu)
2018	NYMEX HH	IFNPCR	7.3	$	(0.16)

Derivative Contracts – Gas Storage

QEP enters into commodity derivative transactions to lock in a margin on gas volumes placed into storage. The following table presents QEP's volumes and average prices for its gas storage commodity derivative swap contracts as of December 31, 2017:

Year	Type of Contract	Index	Total Volumes		Average Swap Price per Unit
			(in millions)		
Gas sales			(MMBtu)		($/MMBtu)
2018	SWAP	IFNPCR	0.6	$	3.06

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	**2017**	2016	**2017**	2016
Current:		(in millions)			
Commodity	Fair value of derivative contracts	**$ 20.6**	$ —	**$ 120.8**	$ 169.8
Long-term:					
Commodity	Fair value of derivative contracts	**2.3**	—	**34.0**	32.0
Total derivative instruments		**$ 22.9**	$ —	**$ 154.8**	$ 201.8

The effects of the change in fair value and settlement of QEP's derivative contracts recorded in "Realized and unrealized gains (losses) on derivative contracts" on the Consolidated Statements of Operations are summarized in the following table:

	Year Ended December 31,		
Derivative contracts not designated as cash flow hedges	**2017**	2016	2015
Realized gains (losses) on commodity derivative contracts		(in millions)	
Production			
Oil derivative contracts	**$ 6.8**	$ 86.3	$ 353.7
Gas derivative contracts	**(22.3)**	44.8	103.4
Gas Storage			
Gas derivative contracts	**—**	2.9	3.8
Realized gains (losses) on commodity derivative contracts	**(15.5)**	134.0	460.9
Unrealized gains (losses) on commodity derivative contracts			
Production			
Oil derivative contracts	**(66.2)**	(217.2)	(244.9)
Gas derivative contracts	**133.6**	(145.4)	62.0
Gas Storage			
Gas derivative contracts	**2.5**	(4.4)	(0.8)
Unrealized gains (losses) on commodity derivative contracts	**69.9**	(367.0)	(183.7)
Total realized and unrealized gains (losses) on commodity derivative contracts related to production and storage contracts	**$ 54.4**	$ (233.0)	$ 277.2
Derivatives associated with the Pinedale Divestiture[(1)]			
Unrealized gains (losses) on commodity derivative contracts			
Production			
Oil derivative contracts	**$ (1.3)**	$ —	$ —
Gas derivative contracts	**(23.5)**	—	—
NGL derivative contracts	**(5.1)**	—	—
Unrealized gains (losses) on commodity derivative contracts related to the Pinedale Divestiture	**$ (29.9)**	$ —	$ —
Total realized and unrealized gains (losses) on commodity derivative contracts	**$ 24.5**	$ (233.0)	$ 277.2

(1) 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 2 – 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" on the Consolidated Statements of Operations.

Note 7 – Restructuring Costs

In April 2016, the Company streamlined its organizational structure, resulting in a reduction of approximately 6% of its total workforce. The total costs related to the 2016 restructuring were approximately $1.9 million and were related to one-time termination benefits. During the year ended December 31, 2016, restructuring costs of $1.9 million were incurred and paid related to the 2016 restructuring. The Company did not incur additional costs related to the 2016 restructuring in 2017.

During 2015, QEP had multiple restructuring events, including the closure of its Tulsa office, which occurred in the third quarter of 2015. The total costs related to the 2015 restructuring events were approximately $8.3 million, of which approximately $5.3 million was related to one-time termination benefits and approximately $3.0 million was related to relocation of certain employees. During the year ended December 31, 2016, restructuring costs of $0.6 million were incurred and paid related to the Tulsa office closure, all of which were related to the relocation of certain employees. The Company did not incur additional costs related to the closure of its Tulsa office.

All restructuring costs were recorded within "General and administrative" expense on the Consolidated Statements of Operations.

Note 8 – Debt

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

	December 31, 2017	December 31, 2016
	(in millions)	
Revolving Credit Facility due 2022	**$ 89.0**	$ —
6.80% Senior Notes due 2018[1]	**—**	134.0
6.80% Senior Notes due 2020[1]	**51.7**	136.0
6.875% Senior Notes due 2021[1]	**397.6**	625.0
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[1]	**500.0**	—
Less: unamortized discount and unamortized debt issuance costs	**(27.5)**	(24.1)
Total long-term debt outstanding	**$ 2,160.8**	$ 2,020.9

(1) During the quarter ended December 31, 2017, the Company issued $500.0 million of 5.625% Senior Notes due in 2026. The Company used the majority of the proceeds from the offering to redeem all of its outstanding 6.80% Senior Notes due in 2018 and fund tender offers for $84.3 million of 6.80% Senior Notes due in 2020 and $227.4 million of its outstanding 6.875% Senior Notes due in 2021. The Company recorded a $32.7 million loss from early extinguishment of debt related to the redemption and tender offers.

Of the total debt outstanding on December 31, 2017, the 6.80% Senior Notes due March 1, 2020, the 6.875% Senior Notes due March 1, 2021 and the 5.375% Senior Notes due October 1, 2022, will mature within the next five years. In addition, the revolving credit facility matures on September 1, 2022.

Credit Facility

In November 2017, QEP entered into the Seventh Amendment to its Credit Agreement, which, among other things, reduced the aggregate principal amount of commitments to $1.25 billion and extended the maturity date, subject to satisfaction of certain conditions, to September 1, 2022. The credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions. The amended credit agreement contains financial covenants (that are defined in the credit agreement) that limit the amount of debt the Company can incur and may limit the amount available to be drawn under the credit facility including: (i) a net funded debt to capitalization ratio that may not exceed 60%, (ii) a leverage ratio under which net funded debt may not exceed 4.25 times consolidated EBITDA (as defined in the credit agreement) for the fiscal quarter ending December 31, 2017, 4.00 times commencing with the fiscal quarter ending March 31, 2018, through the fiscal quarter ending December 31, 2018, and 3.75 times thereafter, and (iii) during a ratings trigger period (as defined), a present value coverage ratio under which the present value of the Company's proved reserves must exceed net funded debt by 1.25 times at any time prior to January 1, 2019, must exceed net funded debt by 1.40 times commencing on January 1, 2019, through December 31, 2019, and must exceed net funded debt by 1.50 times at any time on or after January 1, 2020. The company is currently not subject to the present value coverage ratio. As of December 31, 2017 and 2016, QEP was in compliance with the covenants under the credit agreement.

During the year ended December 31, 2017, QEP's weighted-average interest rates on borrowings from its credit facility were 3.52%. As of December 31, 2017, QEP had $89.0 million of borrowings outstanding and $1.0 million in letters of credit outstanding under the credit facility. As of December 31, 2016, QEP had no borrowings outstanding and $2.8 million in letters of credit outstanding under the credit facility.

Senior Notes
At December 31, 2017, the Company had $2,099.3 million principal amount of senior notes outstanding with maturities ranging from March 2020 to March 2026 and coupons ranging from 5.25% to 6.875%. The senior notes pay interest semi-annually, are unsecured senior obligations and rank equally with all of our other existing and future unsecured and senior obligations. QEP may redeem some or all of its senior notes at any time before their maturity at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. The indentures governing QEP's senior notes contain customary events of default and covenants that may limit QEP's ability to, among other things, place liens on its property or assets.

Note 9 – 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.

Litigation
Landowner Litigation – In October, 2017, the owners of certain surface and mineral interests in Martin and Andrews County, Texas filed suit against QEP, alleging QEP improperly used the surface of the properties and failed to correctly pay royalties, and are seeking money damages and a declaratory judgment that portions of the oil and gas leases covering the properties are no longer in effect. The Company continues to evaluate the allegations and its defenses. The Company is unable to make an estimate of the reasonably possible loss at this early stage.

Commitments

QEP has contracted for gathering, processing, firm transportation and storage 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, storage, drilling, and fractionation contracts are as follows (in millions):

Year		Amount
2018	$	95.6
2019	$	68.4
2020	$	54.9
2021	$	29.9
2022	$	28.3
After 2022	$	122.5

QEP rents office space throughout its scope of operations from third-party lessors. Rental expense from operating leases amounted to $9.6 million, $9.1 million, and $8.0 million during the years ended December 31, 2017, 2016 and 2015, respectively. Minimum future payments under the terms of long-term operating leases for the Company's primary office locations are as follows (in millions):

Year	Amount
2018	$ 7.0
2019	$ 7.2
2020	$ 7.4
2021	$ 7.4
2022	$ 7.2
After 2022	$ 4.8

Note 10 – Share-Based Compensation

QEP issues stock options, restricted share awards and restricted share units under its LTSIP and awards performance share units under its CIP to certain officers, employees, and non-employee directors. QEP recognizes expense over the vesting periods for the stock options, restricted share awards, restricted share units and performance share units. There were 5.0 million shares available for future grants under the LTSIP at December 31, 2017.

Share-based compensation expense related to continuing operations is recognized within "General and administrative" expense on the Consolidated Statements of Operations and is summarized in the table below.

	Year Ended December 31,		
	2017	2016	2015
		(in millions)	
Stock options	**$ 2.3**	$ 2.3	$ 2.9
Restricted share awards	**24.6**	23.7	25.6
Performance share units	**(4.5)**	9.4	6.2
Restricted share units	**—**	0.2	—
Total share-based compensation expense	**$ 22.4**	$ 35.6	$ 34.7

Stock Options

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

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

	Stock Option Assumptions		
	Year Ended December 31,		
	2017	2016	2015
Weighted-average grant date fair value of awards granted during the period	**$ 6.44**	$ 3.77	$ 6.82
Risk-free interest rate range	**1.66% - 1.81%**	0.99% - 1.15%	1.38% - 1.38%
Weighted-average risk-free interest rate	**1.8%**	1.2%	1.4%
Expected price volatility range	**43.82% - 46.70%**	43.42% - 43.66%	36.8% - 36.8%
Weighted-average expected price volatility	**43.9%**	43.4%	36.8%
Expected dividend yield	**—%**	—%	0.37%
Expected term in years at the date of grant	**4.5**	4.5	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, 2016	2,151,957	$ 25.26		
Granted	**418,752**	**16.77**		
Forfeited	**(14,172)**	**15.33**		
Cancelled	**(202,260)**	**27.55**		
Outstanding at December 31, 2017	**2,354,277**	**$ 23.62**	**3.50**	**$ —**
Options Exercisable at December 31, 2017	**1,551,861**	**$ 27.90**	**2.47**	**$ —**
Unvested Options at December 31, 2017	**802,416**	**$ 15.33**	**5.48**	**$ —**

During the years ended December 31, 2017 and 2016, 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 options exercised was $0.1 million during the year ended December 31, 2015. There was no income tax impact for the year ended December 31, 2017. The Company realized an income tax benefit of $0.2 million for the year ended December 31, 2016 and $6.4 million of income tax expense for the year ended December 31, 2015. As of December 31, 2017, $1.6 million of unrecognized compensation cost related to stock options granted under the LTSIP is expected to be recognized over a weighted-average period of 2.04 years.

Restricted Share Awards

Restricted share award grants typically vest in equal installments over a three-year period from the grant date. The grant date fair value is determined based on the closing bid price of the Company's common stock on the grant date. The Company expenses forfeitures of restricted share awards as they occur. The total fair value of restricted share awards that vested during the years ended December 31, 2017, 2016 and 2015, was $18.4 million, $24.3 million and $22.7 million, respectively. There was no income tax impact for the year ended December 31, 2017 and 2016. The Company realized an income tax benefit of $3.2 million for the year ended December 31, 2015. The weighted-average grant date fair value of restricted share awards granted was $13.90 per share, $10.50 per share and $20.92 per share for the years ended December 31, 2017, 2016 and 2015, respectively. As of December 31, 2017, $19.2 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 1.99 years.

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

	Restricted Share Awards Outstanding	Weighted-Average Grant Date Fair Value
		(per share)
Unvested balance at December 31, 2016	3,208,503	$ 14.32
Granted	**2,219,763**	**13.90**
Vested	**(1,392,043)**	**16.53**
Forfeited	**(314,889)**	**14.49**
Unvested balance at December 31, 2017	**3,721,334**	**$ 13.23**

Performance Share Units

The payouts for performance share units are dependent upon the Company's total shareholder return compared to a group of its peers over a three-year period. The awards are denominated in share units and have historically been paid in cash. Beginning with awards granted in 2015, the Company has the option to settle earned awards in cash or shares of common stock under the Company's LTSIP; however, as of December 31, 2017, the Company expects to settle all awards in cash. 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 $5.3 million, $2.8 million and $3.1 million for vested performance share units during the years ended December 31, 2017, 2016 and 2015, respectively. The weighted-average grant date fair value of the performance share units granted during the years ended December 31, 2017, 2016 and 2015, was $16.90, $10.16, and $21.69 per share, respectively. As of December 31, 2017, $1.2 million of unrecognized compensation cost, which represents the unvested portion of the fair market value of performance shares granted, is expected to be recognized over a weighted-average vesting period of 1.89 years.

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, 2016	1,027,280	$ 17.24
Granted	**405,014**	**16.90**
Vested and paid	**(215,439)**	**31.63**
Forfeited	**(17,519)**	**13.88**
Unvested balance at December 31, 2017	**1,199,336**	**$ 14.59**

Restricted Share Units

Employees may elect to defer their grants of restricted share awards and these deferred awards are designated as restricted share units. Restricted share units vest over a three-year period and are deferred into the Company's nonqualified, unfunded deferred compensation plan at the time of vesting. These awards are ultimately delivered in cash. They are classified as liabilities in "Other long-term liabilities" on the Consolidated Balance Sheets and are measured at fair value at the end of each reporting period. The weighted-average grant date fair value of the restricted share units was $16.98 and $10.12 per share for the years ended December 31, 2017 and 2016, respectively. As of December 31, 2017, $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 1.03 years.

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, 2016	18,034	$ 10.12
Granted	**9,924**	**16.98**
Vested	**(6,012)**	**10.12**
Unvested balance at December 31, 2017	**21,946**	**$ 13.22**

Note 11 – Employee Benefits

Pension and other postretirement benefits

The Company provides pension and other postretirement benefits to certain employees through three retirement benefit plans: the QEP Resources, Inc. Retirement Plan (the Pension Plan), the Supplemental Executive Retirement Plan (the SERP), and a postretirement medical plan (the 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, 2017, covers 30 active and suspended participants, or 5%, of QEP's active employees, and 184 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, 2017, the Company made contributions of $4.0 million to the Pension Plan and expects to contribute approximately $4.0 million to the Pension Plan in 2018. Contributions to the Pension Plan increase plan assets. Due to the Pension Plan freeze on January 1, 2016, the Company began making additional contributions for eligible employees who were active participants in the Pension Plan on December 31, 2015 based on the eligible employee's age as of December 31, 2015. During the year ended December 31, 2017, QEP contributed $0.4 million for these employees.

As a result of the Company's 2014 divestitures and retirements in 2015, the number of active participants in the Pension Plan fell to 50 participants during the year ended December 31, 2015, which is the minimum number of active participants for a plan to meet the qualification requirements of the minimum participation rules under the Internal Revenue Code. In order to prevent disqualification, the Pension Plan was amended in June 2015 and was frozen effective January 1, 2016, such that employees do not earn additional defined benefits for future services except for purposes of determining eligibility for an early retirement benefit. This change resulted in a non-cash curtailment loss of $11.2 million recognized on the Consolidated Statements of Operations within "Interest and other income (expense)" expense during the year ended December 31, 2015. A curtailment is recognized immediately when there is a significant reduction in, or an elimination of, defined benefit accruals for present employees' future services.

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, 2017, the Company made contributions of $2.0 million to its SERP and expects to contribute approximately $0.7 million in 2018. 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".

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 30 active, pension eligible employees, 17 are also eligible for the Medical Plan when they retire. As of December 31, 2017, 55 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, 2017, the Company made contributions of $0.1 million and expects to contribute approximately $0.3 million of benefits in 2018. At December 31, 2017 and 2016, 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.

In accordance with the early adoption of ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the presentation of net periodic pension cost and net periodic postretirement benefit cost,* the Company recast years ended December 31, 2016 and 2015 by recognizing service costs related to SERP and Medical Plan benefits within "General and administrative" expense on the Consolidated Statements of Operations. All other expenses related to the Pension Plan, SERP and Medical Plan are recognized within "Interest and other income (expense)" on the Consolidated Statements of Operations.

The accumulated benefit obligation for all defined-benefit pension plans was $128.7 million and $124.5 million at December 31, 2017 and 2016, 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, 2017 and 2016, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2017 and 2016:

	Pension Plan and SERP benefits		Medical Plan benefits	
	2017	2016	**2017**	2016
Change in benefit obligation	(in millions)			
Benefit obligation at January 1,	**$ 129.2**	$ 120.3	**$ 5.4**	$ 5.2
Service cost	**0.8**	1.2	**—**	—
Interest cost	**4.7**	5.2	**0.1**	0.2
Curtailments	**(0.3)**	—	**—**	—
Benefit payments	**(6.9)**	(7.8)	**(0.1)**	(0.4)
Plan amendments	**—**	—	**(2.4)**	—
Actuarial loss (gain)	**2.5**	10.3	**(0.1)**	0.4
Benefit obligation at December 31,	**$ 130.0**	$ 129.2	**$ 2.9**	$ 5.4
Change in plan assets				
Fair value of plan assets at January 1,	**$ 86.1**	$ 79.3	**$ —**	$ —
Actual return on plan assets	**15.3**	7.4	**—**	—
Company contributions to the plan	**6.0**	7.2	**0.1**	0.4
Benefit payments	**(6.9)**	(7.8)	**(0.1)**	(0.4)
Fair value of plan assets at December 31,	**100.5**	86.1	**—**	—
Underfunded status (current and long-term)	**$ (29.5)**	$ (43.1)	**$ (2.9)**	$ (5.4)
Amounts recognized in balance sheets				
Accounts payable and accrued expenses	**$ (1.5)**	$ (2.5)	**$ (0.2)**	$ (0.3)
Other long-term liabilities	**(27.9)**	(40.6)	**(2.6)**	(5.1)
Total amount recognized in balance sheet	**$ (29.4)**	$ (43.1)	**$ (2.8)**	$ (5.4)
Amounts recognized in AOCI				
Net actuarial loss (gain)	**$ 15.0**	$ 23.5	**$ (0.5)**	$ (0.4)
Prior service cost	**1.2**	2.9	**(1.2)**	1.0
Total amount recognized in AOCI	**$ 16.2**	$ 26.4	**$ (1.7)**	$ 0.6

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		
	2017	2016	2015	**2017**	2016	2015
Components of net periodic benefit cost	(in millions)					
Service cost	**$ 0.8**	$ 1.2	$ 2.1	**$ —**	$ —	$ —
Interest cost	**4.7**	5.2	4.9	**0.1**	0.2	0.2
Expected return on plan assets	**(5.4)**	(5.6)	(5.7)	**—**	—	—
Curtailment loss	**0.7**	—	11.2	**—**	—	—
Settlements	**0.2**	—	—	**—**	—	—
Amortization of prior service costs	**1.0**	1.1	1.7	**(0.3)**	0.2	0.2
Amortization of actuarial loss	**0.5**	0.8	0.5	**(0.1)**	—	—
Periodic expense	**$ 2.5**	$ 2.7	$ 14.7	**$ (0.3)**	$ 0.4	$ 0.4
Components recognized in accumulated other comprehensive income						
Current period prior service cost	**$ (0.7)**	$ —	$ 0.9	**$ (2.5)**	$ —	$ —
Current period actuarial (gain) loss	**(7.5)**	8.5	2.2	**(0.1)**	0.4	(1.4)
Amortization of prior service cost	**(1.0)**	(1.1)	(12.9)	**0.3**	(0.2)	(0.2)
Amortization of actuarial gain (loss)	**(0.5)**	(0.8)	(0.5)	**0.1**	—	—
Loss on curtailment in current period	**(0.3)**	—	(7.1)	**—**	—	—
Settlements	**(0.2)**	—	—	**—**	—	—
Total amount recognized in accumulated other comprehensive income	**$ (10.2)**	$ 6.6	$ (17.4)	**$ (2.2)**	$ 0.2	$ (1.6)

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 2018 is $1.9 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 2018 is $0.3 million, which represents amortization of prior service cost recognized and actuarial gains. Amortization of prior service costs and actuarial gains or losses out of AOCI are recognized in the Consolidated Statements of Operations in "Interest and other income (expense)".

Following are the weighted-average assumptions (weighted by the plan level benefit obligation for pension benefits) used by the Company to calculate the Pension Plan, SERP and Medical Plan obligations at December 31, 2017 and 2016:

	Pension Plan and SERP benefits		Medical Plan benefits	
	2017	2016	**2017**	2016
Discount rate	**3.52%**	3.96%	**3.60%**	4.10%
Rate of increase in compensation[(1)]	**3.50%**	3.50%	**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 value of the Pension Plan. As such, for the years ended December 31, 2017 and 2016, the rate of increase in compensation only includes the SERP and Medical Plan.

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		
	2017	2016	2015	**2017**	2016	2015
Discount rate	**4.00%**	4.23%	3.94%	**4.10%**	4.40%	4.00%
Expected long-term return on plan assets	**6.00%**	6.50%	6.75%	**n/a**	n/a	n/a
Rate of increase in compensation[(1)]	**3.50%**	4.00%	4.00%	**3.50%**	4.00%	4.00%

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

In selecting the assumption for expected long-term rate of return on assets, the Company considers the average rate of return expected on the funds to be invested to provide benefits. This includes considering the plan's asset allocation, historical returns on these types of assets, the current economic environment and the expected returns likely to be earned over the life of the plan. No plan assets are expected to be returned to the Company in 2018. 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.

In conjunction with the issuance of ASU 2015-07, *Fair Value Measurements (Topic 820): Disclosures for Investment in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)*, QEP no longer presents its Pension Plan assets in the fair value hierarchy, in accordance with the provisions of ASC 820, *Fair Value Measurements and Disclosures,* as all investments are measured at NAV as a practical expedient, which are now required to be excluded from the fair value hierarchy.

The following table summarizes investments for which fair value is measured using the NAV per share practical expedient as of December 31, 2017 and 2016, respectively:

	December 31, 2017		December 31, 2016	
	Total	**Percentage of total**	Total	Percentage of total
	(in millions, except percentages)			
Cash and short-term investments	**$ 0.5**	**—%**	$ 3.5	4%
Equity securities:				
Domestic	**35.0**	**35%**	39.3	46%
International	**15.3**	**15%**	21.6	25%
Fixed income	**49.7**	**50%**	21.7	25%
Total investments	**$ 100.5**	**100%**	$ 86.1	100%

Expected Benefit Payments
As of December 31, 2017, the following future benefit payments are expected to be paid:

	Pension Plan and SERP benefits	Medical Plan benefits
	(in millions)	
2018	$ 6.6	$ 0.2
2019	$ 8.1	$ 0.2
2020	$ 7.6	$ 0.2
2021	$ 8.3	$ 0.2
2022	$ 6.8	$ 0.2
2023 through 2026	$ 39.1	$ 0.6

Employee Investment Plan

QEP employees may participate in the QEP Employee Investment Plan, a defined-contribution plan (the 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. 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,		
	2017	2016	2015
Employees not covered by the Pension Plan or SERP[1]			
Maximum employer matching of qualifying earnings	**8%**	8%	8%
Employees covered by the Pension Plan but not the SERP[1]			
Maximum employer matching of qualifying earnings	**8%**	8%	6%
Employees covered by both the Pension Plan and the SERP[1]			
Maximum employer matching of qualifying earnings	**6%**	6%	6%

(1) The Pension Plan was frozen effective January 1, 2016.

The Company may contribute a discretionary portion beyond the Company's matching contribution to employees not in the Pension Plan or SERP. The Company recognizes expense equal to its yearly contributions, which amounted to $6.0 million, $5.6 million and $6.3 million during the years ended December 31, 2017, 2016 and 2015, respectively.

Note 12 – Income Taxes

On December 22, 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 Tax Legislation also repeals the corporate alternative minimum tax (AMT). Several provisions of the new tax law such as limitations on the deductibility of interest expense and certain executive compensation and the inability to use Section 1031 like-kind exchanges for assets such as machinery and equipment could apply to QEP; however, we do not believe that they will materially impact QEP's financial statements. 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. The Company will continue to analyze the Tax Legislation to determine the full impact of the new law, 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,		
	2017	2016	2015
Federal income tax provision (benefit)		(in millions)	
Current	**$ 2.1**	$ (55.5)	$ (112.3)
Deferred	**(339.8)**	(614.3)	34.5
State income tax provision (benefit)			
Current	**0.5**	(1.5)	(6.6)
Deferred	**25.0**	(36.9)	(9.2)
Total income tax provision (benefit)	**$ (312.2)**	$ (708.2)	$ (93.6)

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,		
	2017	2016	2015
Federal income taxes statutory rate	**35.0 %**	35.0 %	35.0 %
Increase (decrease) in rate as a result of:			
State income taxes, net of federal income tax benefit[(1)]	**(40.1)%**	2.4 %	4.2 %
Federal rate change[(2)]	**741.3 %**	— %	— %
State rate change	**2.1 %**	(1.1)%	— %
Penalties	**(0.4)%**	— %	(0.3)%
Return to provision adjustment	**(0.7)%**	— %	(0.3)%
Uncertain tax provision (federal rate change)	**(7.7)%**	— %	— %
Other	**(1.8)%**	— %	(0.1)%
Effective income tax rate	**727.7 %**	36.3 %	38.5 %

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

(2) The new 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.

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

	December 31,	
	2017[(1)]	2016
Deferred tax liabilities	(in millions)	
Property, plant and equipment	**$ 898.7**	$ 1,135.0
Deferred tax assets		
Net operating loss and tax credit carryforwards	**$ 308.8**	$ 161.6
Employee benefits and compensation costs	**26.4**	49.0
Bonus and vacation accrual	**6.2**	11.4
Commodity price derivatives	**29.9**	74.3
Other	**9.4**	12.8
Total deferred tax assets	**380.7**	309.1
Net deferred income tax liability	**$ 518.0**	$ 825.9
Balance sheet classification		
Deferred income tax liability – noncurrent	**518.0**	825.9
Net deferred income tax liability	**$ 518.0**	$ 825.9

(1) The $307.9 million decrease in net deferred income tax liability as of December 31, 2017 is primarily related to a $318.0 million decrease from the federal rate change from 35% to 21%.

The amounts and expiration dates of net operating loss and tax credit carryforwards at December 31, 2017, are as follows:

	Expiration Dates	Amounts
		(in millions)
State net operating loss and tax credit carryforwards	2018-2037	**$ 95.8**
State net operating loss valuation allowance		**$ (56.8)**
U.S. net operating loss	2036-2037	**$ 250.4**
U.S. alternative minimum tax credit	Indefinite	**$ 19.5**

The valuation allowance of $56.8 million was established in 2014 and 2017 against the available state net operating loss and is related primarily to losses incurred in Oklahoma and Louisiana. Due to the 2014 property sales in the Other Southern area in which the Company sold its interests in most of its properties in Oklahoma, the Company does not forecast sufficient taxable income to utilize the net operating loss in Oklahoma. In 2017, a valuation allowance of $31.8 million was established against Louisiana's net operating loss as the Company does not forecast sufficient taxable income to utilize the entire net operating loss in Louisiana.

The Tax Legislation eliminated AMT, and allowed the ability to offset our regular tax liability or claim refunds for taxable years 2018 through 2021 for AMT credits carried forward from prior years. The Company currently anticipates it will realize approximately $19.5 million in AMT value over the next four years with approximately half of this value estimated to be realized in 2019 for taxable year 2018.

Unrecognized Tax Benefit

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

The following is a reconciliation of our beginning and ending amounts of unrecognized tax benefits for the years ended December 31, 2017 and 2016:

	Unrecognized Tax Benefits	
	2017	2016
	(in millions)	
Balance as of January 1,	**$ 15.6**	$ 15.6
Federal benefit of state (change from 35% to 21%)	**3.4**	—
Balance as of December 31,	**$ 19.0**	$ 15.6

As of December 31, 2017 and 2016, QEP had approximately $19.0 million and $15.6 million, respectively, of unrecognized tax benefit that would impact its effective tax rate if recognized. The difference is due to the change in the Federal tax rate in 2017 from 35% to 21%, which affects the federal benefit of the state deduction to the unrecognized tax position.

Note 13 – Quarterly Financial Information (unaudited)

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

2017	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
	(in millions, except per share amounts or otherwise specified)				
Revenues	**$ 420.1**	**$ 383.7**	**$ 390.1**	**$ 429.0**	**$ 1,622.9**
Operating income (loss)	**(5.2)**	**(0.9)**	**132.1**	**(24.5)**	**101.5**
Net income (loss)	**76.9**	**45.4**	**(3.3)**	**150.3**	**269.3**
Net gain (loss) from asset sales and impairment	**(0.1)**	**19.8**	**157.1**	**(42.2)**	**134.6**
Nonrecurring items in operating income (loss)[1]	**—**	**—**	**8.2**	**—**	**8.2**
Per share information					
Basic EPS	**$ 0.32**	**$ 0.19**	**$ (0.01)**	**$ 0.62**	**$ 1.12**
Diluted EPS	**0.32**	**0.19**	**(0.01)**	**0.62**	**1.12**
Production information					
Total equivalent production (Mboe)	**13,090.3**	**13,860.6**	**14,124.1**	**12,069.9**	**53,144.9**
Total equivalent production (Bcfe)	**78.6**	**83.2**	**84.7**	**72.1**	**318.6**
2016					
Revenues	$ 261.3	$ 333.7	$ 382.4	$ 399.7	$ 1,377.1
Operating income (loss)	(1,379.0)	(92.1)	(93.1)	(36.5)	(1,600.7)
Net income (loss)	(863.8)	(197.0)	(50.9)	(133.3)	(1,245.0)
Net gain (loss) from asset sales and impairment	(1,181.9)	(1.6)	0.3	(6.1)	(1,189.3)
Nonrecurring items in operating income (loss)[1]	7.7	—	25.0	—	32.7
Per share information					
Basic EPS	$ (4.55)	$ (0.90)	$ (0.21)	$ (0.56)	$ (5.62)
Diluted EPS	(4.55)	(0.90)	(0.21)	(0.56)	(5.62)
Production information					
Total equivalent production (Mboe)	13,776.4	13,882.4	14,445.7	13,675.7	55,780.2
Total equivalent production (Bcfe)	82.7	83.3	86.6	82.1	334.7

(1) Reflects legal expenses and loss contingencies incurred during the years ended December 31, 2017 and 2016.

Note 14 – 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. All of QEP's properties are located in the United States.

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:

	December 31,	
	2017	2016
	(in millions)	
Proved properties	**$ 12,470.9**	$ 14,232.5
Unproved properties, net	**1,095.8**	871.5
Total proved and unproved properties	**13,566.7**	15,104.0
Accumulated depreciation, depletion and amortization	**(6,642.9)**	(8,797.7)
Net capitalized costs	**$ 6,923.8**	$ 6,306.3

Costs Incurred
The costs incurred in oil and gas acquisition, exploration and development activities are displayed in the table below. Development costs are net of the change in accrued capital costs of $60.6 million and ARO additions and revisions of $32.0 million during the year ended December 31, 2017. The costs incurred for the development of reserves that were classified as proved undeveloped were approximately $389.3 million in 2017, $258.1 million in 2016, and $490.4 million in 2015.

	Year Ended December 31,		
	2017	2016	2015
		(in millions)	
Proved property acquisitions	**$ 269.6**	$ 431.6	$ 49.6
Unproved property acquisitions	**532.4**	208.7	39.8
Other acquisitions	**13.2**	—	—
Exploration costs (capitalized and expensed)	**32.7**	13.4	8.7
Development costs	**1,189.3**	509.2	1,010.3
Total costs incurred	**$ 2,037.2**	$ 1,162.9	$ 1,108.4

Results of Operations
Following are the results of operations of QEP's oil and gas producing activities, before allocated corporate overhead and interest expenses.

	Year Ended December 31,		
	2017	2016	2015
		(in millions)	
Revenues	**$ 1,548.1**	$ 1,271.0	$ 1,390.4
Production costs	**675.4**	616.7	654.1
Exploration expenses	**22.0**	1.7	2.7
Depreciation, depletion and amortization	**735.1**	852.3	870.8
Impairment	**72.3**	1,194.3	55.6
Total expenses	**1,504.8**	2,665.0	1,583.2
Income (loss) before income taxes	**43.3**	(1,394.0)	(192.8)
Income tax benefit (expense)	**(16.0)**	517.2	70.6
Results of operations from producing activities excluding allocated corporate overhead and interest expenses	**$ 27.3**	$ (876.8)	$ (122.2)

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 includes 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, 2017 and 2016, and retained RSC and DeGolyer and MacNaughton to prepare the estimates of all of its proved reserves as of December 31, 2015. 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, 2017, 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, 2017, all of the Company's oil and gas reserves are attributable to properties within the United Sates. A summary of the Company's change in quantities of proved oil, gas and NGL reserves for the years ended December 31, 2015, 2016 and 2017 are as follows:

	Oil	Gas	NGL	Total[13]
	(MMbbl)	(Bcf)	(MMbbl)	(MMboe)
Balance at December 31, 2014	172.5	2,317.2	96.6	655.3
Revisions of previous estimates[1]	(47.0)	(463.8)	(55.3)	(179.6)
Extensions and discoveries[2]	85.6	467.7	21.8	185.4
Purchase of reserves in place[3]	2.0	3.2	0.6	3.1
Sale of reserves in place[4]	(0.4)	(34.3)	(0.2)	(6.3)
Production	(19.6)	(181.1)	(4.7)	(54.5)
Balance at December 31, 2015	193.1	2,108.9	58.8	603.4
Revisions of previous estimates[5]	(9.7)	412.8	(0.3)	58.8
Extensions and discoveries[6]	13.0	158.1	3.3	42.6
Purchase of reserves in place[7]	62.7	54.6	11.5	83.3
Sale of reserves in place[8]	(0.2)	(3.6)	(0.1)	(0.9)
Production	(20.3)	(177.0)	(6.0)	(55.8)
Balance at December 31, 2016	238.6	2,553.8	67.2	731.4
Revisions of previous estimates[9]	**3.7**	**12.5**	**(3.1)**	**2.7**
Extensions and discoveries[10]	**59.1**	**101.9**	**10.4**	**86.4**
Purchase of reserves in place[11]	**46.6**	**125.5**	**8.7**	**76.3**
Sale of reserves in place[12]	**(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**
Proved developed reserves				
Balance at December 31, 2014	99.3	1,288.4	52.2	366.2
Balance at December 31, 2015	109.7	1,245.3	34.4	351.6
Balance at December 31, 2016	103.2	1,309.8	35.7	357.2
Balance at December 31, 2017	**116.0**	**655.5**	**27.9**	**253.1**
Proved undeveloped reserves				
Balance at December 31, 2014	73.2	1,028.8	44.4	289.1
Balance at December 31, 2015	83.4	863.6	24.4	251.8
Balance at December 31, 2016	135.4	1,244.0	31.5	374.2
Balance at December 31, 2017	**204.5**	**1,138.1**	**37.3**	**431.6**

(1) Revisions of previous estimates in 2015 include: 126.2 MMboe of negative revisions due to lower pricing and 67.2 MMboe of negative revisions unrelated to pricing, partially offset by 13.7 MMboe of positive performance revisions. Negative pricing revisions were driven by lower oil, gas and NGL prices. Negative other revisions included operating in ethane rejection in Pinedale and the Uinta Basin.

(2) Extensions and discoveries in 2015 increased proved reserves by 185.4 MMboe, primarily related to extensions and discoveries in the Williston Basin of 68.2 MMboe, the Uinta Basin of 53.2 MMboe, and the Permian Basin of 49.6 MMboe. All of these extensions and discoveries related to new well completions and associated new PUD locations.

(3) Purchase of reserves in place in 2015 related to the acquisition of additional interests in QEP operated wells in the Williston and Permian basins as discussed in Note 2 – Acquisitions and Divestitures.

(4) Sale of reserves in place in 2015 relate to the divestiture of QEP's interest in certain non-core properties as discussed in Note 2 – Acquisitions and Divestitures.

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

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

(7) Purchase of reserves in place in 2016 primarily relates to QEP's 2016 Permian Basin Acquisition as discussed in Note 2 – Acquisitions and Divestitures.

(8) Sale of reserves in place in 2016 relates to the divestiture of QEP's interest in certain non-core properties as discussed in Note 2 – Acquisitions and Divestitures.

(9) 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.

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

(11) 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 2 – Acquisitions and Divestitures.

(12) Sale of reserves in place in 2017 was primarily related to QEP's Pinedale Divestiture as discussed in Note 2 – 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, 2017, 2016 and 2015, 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 2017, 2016 and 2015, 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,		
	2017	2016	2015
Average benchmark price per unit:			
Oil price (per bbl)	**$ 51.34**	$ 42.75	$ 50.28
Gas price (per MMBtu)	**$ 2.98**	$ 2.48	$ 2.59

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 $486.5 million in 2018, $710.0 million in 2019 and $1,006.2 million in 2020. 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. In addition, QEP estimates that its future development costs relating to wells waiting on completion and its refracturing program, which are not classified as PUD, are approximately $132.6 million in 2018.

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.
- Future market conditions, government regulations, reservoir conditions and risks inherent in the production of oil and gas may cause production rates in future years to vary significantly from those rates used in the calculations.
- Future revenues may be subject to different production, severance and property taxation rates.
- The selection of a 10% discount rate is arbitrary and may not be a reasonable factor in adjusting for future economic conditions or in considering the risk that is part of realizing future net cash flows from the reserves.

The standardized measure of discounted future net cash flows relating to proved reserves is presented in the table below:

	Year Ended December 31,		
	2017	2016	2015
		(in millions)	
Future cash inflows	**$ 22,028.9**	$ 16,239.8	$ 15,325.3
Future production costs	**(9,074.2)**	(7,789.0)	(7,389.9)
Future development costs[(1)]	**(4,726.0)**	(3,432.9)	(2,202.5)
Future income tax expenses[(2)]	**(1,439.1)**	(913.4)	(1,169.3)
Future net cash flows	**6,789.6**	4,104.5	4,563.6
10% annual discount for estimated timing of net cash flows	**(3,692.3)**	(2,176.5)	(2,087.3)
Standardized measure of discounted future net cash flows	**$ 3,097.3**	$ 1,928.0	$ 2,476.3

(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, 2017, assumes the new 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,		
	2017	2016	2015
		(in millions)	
Balance at January 1,	**$ 1,928.0**	$ 2,476.3	$ 5,340.0
Sales of oil, gas and NGL produced, net of production costs	**(872.7)**	(654.3)	(736.3)
Net change in sales prices and in production (lifting) costs related to future production	**1,457.2**	(739.4)	(6,307.8)
Net change due to extensions and discoveries	**556.8**	81.8	1,765.7
Net change due to revisions of quantity estimates	**9.9**	122.7	(1,350.2)
Net change due to purchases of reserves in place	**342.7**	256.5	29.7
Net change due to sales of reserves in place	**(504.7)**	(4.3)	(48.8)
Previously estimated development costs incurred during the period	**475.4**	374.6	865.0
Changes in estimated future development costs	**(283.4)**	(476.5)	560.7
Accretion of discount	**235.7**	311.1	752.9
Net change in income taxes	**(227.4)**	205.4	1,554.4
Other	**(20.2)**	(25.9)	51.0
Net change	**1,169.3**	(548.3)	(2,863.7)
Balance at December 31,	**$ 3,097.3**	$ 1,928.0	$ 2,476.3

Note 15 – Subsequent Event

In February 2018, in conjunction with the 2017 Permian Basin Acquisition, QEP entered into agreements to acquire oil and gas properties in the Permian Basin for an aggregate purchase price of $36.1 million, subject to customary purchase price adjustments. The transactions are expected to be funded with borrowings under the credit facility and are expected to close in the first half of 2018.

In February 2018, the Board of Directors approved a retention and severance program in conjunction with the announcement of several strategic initiatives, which include selling assets and focusing the Company's activities on its Permian Basin operations. The estimated amount of general and administrative expenses to be incurred related to this program in 2018 is approximately $20.0 million.

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, 2017. Based on such evaluation, such officers have concluded that, as of December 31, 2017, 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, 2017, 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, 2017, 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, 2017. 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, 2017, 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

Approval of Executive Retention and Severance Compensation Program

On February 26, 2018, QEP's Board of Directors approved an executive severance compensation program, pursuant to which each of QEP's named executive officers have entered into an Executive Severance Compensation Program letter agreement (the Severance Letters). The Severance Letters provide that in the event the executive's employment with QEP is terminated without cause or the executive resigns his employment for good reason (as such terms are defined in the Severance Letters), and such termination or resignation occurs prior to September 30, 2020, the executive will be entitled to receive the following severance payments and benefits, subject to the execution and non-revocation of a release of claims agreement containing, among other terms, confidentiality and non-solicitation restrictions, and other customary conditions:

- A lump sum cash payment equal to 1.5 times (2.5 times for Mr. Stanley and 2.0 times for Mr. Doleshek) the sum of the executive's annual base salary and annual target bonus award opportunity;
- A pro-rated bonus award for the year of termination, which shall be at the target level for executives other than Mr. Stanley and Mr. Doleshek, which shall be based on actual performance for the year;
- Accelerated vesting of all outstanding equity and long-term incentive awards, provided that the vesting of performance-based awards is based on and subject to the actual level of performance in relation to applicable performance measures;
- A lump sum cash payment representing 24 months of premium payment amounts required to continue the executive's and the executive's covered dependents' medical, dental and vision coverage pursuant to COBRA; and
- For executives participating in the QEP Resources, Inc. Retirement Plan and/or the QEP Resources Inc. Supplemental Executive Retirement Plan, a cash payment representing two additional years of service credit under such plans.

The severance benefits payable under the Severance Letters are in lieu of any other severance entitlements applicable to the participating executives, provided that in the event a change in control of QEP occurs during the term of the Severance Letters, the executives will not receive the benefits under the Severance Letters and will instead be eligible to receive the benefits provided under the QEP Resources, Inc. Executive Severance Compensation Plan - CIC, as previously adopted by the Board of Directors.

In addition, on February 26, 2018, QEP's Board of Directors approved an executive retention award program, pursuant to which each of QEP's named executive officers (other than Mr. Stanley and Mr. Doleshek) have entered into an Executive Retention Bonus letter agreement (the Retention Letters). The Retention Letters provide, for each of our named executive officers other than Mr. Stanley and Mr. Doleshek, for a one-time cash retention payment of $500,000, payable within 15 days after March 1, 2019, subject to continued employment through such date. If the executive's employment is terminated by QEP without cause or the executive resigns employment for good reason prior to such date, the executive will be eligible to receive a pro-rated amount of the retention payment.

The foregoing description of the Severance Letters and the Retention Letters is not complete and is qualified in its entirety by reference to the text of the full letter agreements, which are attached as Exhibits 10.29 and 10.30, respectively to this Form 10-K and are incorporated herein by reference.

Letter Agreement

On February 28, 2018, QEP entered into an agreement (the Agreement) with Elliott Management Corporation, a Delaware corporation (Elliott).

Under the terms of the Agreement, the Company agreed to issue a press release announcing, among other things, certain strategic initiatives, a copy of which was furnished as an exhibit to the Company's Form 8-K filed on February 28, 2018.

The Agreement also provides that the Company will include a proposal in its definitive proxy statement (the Proxy Statement) for its 2018 annual meeting (the Annual Meeting) asking the Company's shareholders to approve an amendment to the Company's Amended and Restated Certificate of Incorporation to immediately declassify the existing board structure and provide for the annual election of directors (the Declassification Amendment). The Company has agreed to recommend to its shareholders that they vote in favor of the Declassification Amendment. In connection with the Declassification Amendment, all of the current members of the Company's board of directors (the Board), other than Mr. Thacker, will tender their resignations on the date of the Annual Meeting, to be effective on such date. Should the Declassification Amendment be approved by the Company's shareholders, all of the directors shall serve until the 2019 annual meeting, including Mr. Thacker whose remaining term will expire at the 2019 annual meeting. If the Declassification Amendment is not approved, all of the directors, other than Mr. Thacker, shall be nominated to the class and for the term that they would have otherwise served prior to their resignation.

The Agreement also provides that at the Annual Meeting, Elliott will vote or cause to be voted any shares of common stock of the Company that it or certain of its affiliates have the right to vote, as of the record date, in favor of the election of directors nominated by the Company and in accordance with the recommendations of the Board on the other proposals in the Proxy Statement not related to an extraordinary transaction.

Elliott further agreed that, subject to certain exceptions, until the earlier of (i) January 15, 2019, and (ii) thirty (30) days prior to the first day of the time period established pursuant to the Company's bylaws for shareholders to deliver notice to the Company of director nominations to be brought before the 2019 annual meeting, not to, among other things and subject to certain exceptions: (a) make any "solicitation" of proxies (as such terms are used in the proxy rules of the Securities and Exchange Commission), (b) form, join or act in concert with any "group" as defined in Section 13(d)(3) of the United States Securities Exchange Act of 1934 (the Exchange Act), other than solely with affiliates of Elliott with respect to voting securities now or hereafter held by them, (c) acquire, offer or seek to acquire any voting securities of the Company that would result in Elliott having a net long position of, or voting rights with respect to, more than 9.9% of the voting securities of the Company, (d) effect or seek to effect, whether alone or in concert with others, any extraordinary transaction involving the Company, (e) enter into any voting trust or similar arrangement, (f) seek to (i) elect or appoint to, or have representation on, the Board or (ii) remove any member of the Board, (g) make or be the proponent of any shareholder proposal (pursuant to Rule 14a-8 under the Exchange Act or otherwise) or (h) enter into any discussions, negotiations, agreements or understandings with any third party with respect to the foregoing.

A copy of the Agreement is filed with this Form 10-K and attached hereto as Exhibit 10.31 and incorporated by reference herein. The foregoing description of the Agreement is qualified in its entirety by reference to the full text of the Agreement.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by Item 10 concerning QEP's directors and nominees for directors and other corporate governance matters will be presented in the Company's definitive Proxy Statement prepared for the solicitation of proxies in connection with the Company's Annual Meeting of Stockholders, which the Company expects to file with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2017 (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 17, 2017 (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 18, 2017)
3.2	Amended and Restated Bylaws, dated effective October 23, 2017 (incorporated by reference to Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on October 25, 2017)
4.1	Indenture dated as of March 1, 2001, between Questar Market Resources, Inc. (predecessor-in-interest to QEP Resources, Inc.) and Bank One, NA, (predecessor-in-interest to Wells Fargo Bank, National Association), as Trustee (incorporated by reference to Exhibit 4.01 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on March 13, 2001)

4.2	6.80% Notes due 2020 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on September 2, 2009)
4.3	Officers' Certificate, dated as of August 31, 2009, setting forth the terms of the 6.80% Notes due 2020 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on September 2, 2009)
4.4	Officers' Certificate, dated as of August 16, 2010 (including the form of the 6.875% Notes due 2021) (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on August 16, 2010)
4.5	Indenture, dated as of March 1, 2012, between the Company and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on March 1, 2012)
4.6	Officer's Certificate, dated as of March 1, 2012 (including the form of the 5.375% Notes due 2022) (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on March 1, 2012)
4.7	Officer's Certificate, dated as of September 12, 2012 (including form of the 5.250% Notes due 2023) (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on September 14, 2012)
4.8	Officer's Certificate, dated as of November 21, 2017 (including the form of the 5.625% Senior Notes due 2026) (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K, filed with the Securities Exchange Commission on November 21, 2017)
10.1	Credit Agreement, dated as of August 25, 2011, among QEP Resources, Inc., Wells Fargo Bank, National Association, as the administrative agent, letter of credit issuer and swing line lender, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on August 29, 2011), as amended by the First Amendment to Credit Agreement, dated as of July 6, 2012, the Second Amendment to Credit Agreement, dated as of August 13, 2013 (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on August 16, 2013), the Third Amendment to Credit Agreement, dated as of January 31, 2014 (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on May 7, 2014), the Fourth Amendment to Credit Agreement and Commitment Increase Agreement, dated as of December 2, 2014 (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on December 4, 2014), the Fifth Amendment to Credit Agreement, dated as of November 23, 2015 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on November 23, 2015), the Sixth Amendment to Credit Agreement, dated as of May 5, 2017 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on May 9, 2017), the Seventh Amendment to Credit Agreement, dated as of November 21, 2017 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on November 27, 2017)
10.2+	Employee Matters Agreement, dated as of June 14, 2010, by and between Questar Corporation and QEP Resources, Inc. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on June 16, 2010)
10.3+	Amended and Restated QEP Resources, Inc. Deferred Compensation Wrap Plan, dated May 15, 2017 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q, filed by the Company with the Securities and Exchange Commission on July 26, 2017)
10.4+	Amended and Restated QEP Resources, Inc. Deferred Compensation Plan for Directors, dated July 24, 2017 (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q, filed by the Company with the Securities and Exchange Commission on July 26, 2017)
10.5+	Cash Incentive Plan, dated effective as of January 1, 2012 (incorporated by reference to Appendix A to the Company's Proxy Statement on Schedule 14A, filed with the Securities and Exchange Commission on April 3, 2012), as amended by Amendment Number One to Cash Incentive Plan, effective as of October 26, 2015 (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on October 29, 2015)
10.6+	2010 Long-Term Stock Incentive Plan, adopted June 12, 2010 (incorporated by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on June 16, 2010), as amended by Amendment Number One to Long-Term Stock Incentive Plan, effective as of October 26, 2015 (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on October 29, 2015)
10.7+	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)

10.8+	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)
10.9+	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)
10.10+	Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to the CEO and CFO in 2011, 2012 and 2013 (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)
10.11+	Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to executive officers other than the CEO and CFO in 2011, 2012 and 2013 (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)
10.12+	Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to executive officers in 2014 and 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 January 23, 2014)
10.13+	Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to executive officers in 2016 and 2017 (incorporated by reference to Exhibit 10.4, to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on October 29, 2015)
10.14+	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)
10.15+	Form of Restricted Stock Agreement for restricted stock granted to executive officers in 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 January 23, 2014)
10.16+	Form of Restricted Stock Agreement for restricted stock granted to executive officers in 2016 and 2017 (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on October 29, 2015)
10.17*+	Form of Restricted Stock Agreement for restricted stock granted to executive officers in 2018
10.18+	Form of Restricted Stock Agreement for restricted stock granted to non-employee directors (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on October 29, 2015)
10.19+	Form of Phantom Stock Agreement for phantom stock granted to non-employee directors (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)
10.20+	Form of Performance Share Unit Award Agreement for performance share units granted to executive officers in 2015 (incorporated by reference to Exhibit 10.42 to the Company's Annual Report on Form 10-K, filed with the Securities and Exchange Commission on February 24, 2015)
10.21+	Form of Performance Share Unit Award Agreement for performance share units granted to executive officers in 2016 (incorporated by reference to Exhibit 10.7 to the Company's Annual Report on Form 8-K, filed with the Securities and Exchange Commission on October 29, 2015)
10.22+	Form of Performance Share Unit Award Agreement for performance share units granted to executive officers in 2017 (incorporated by reference to Exhibit 10.33 to the Company's Annual Report on Form 10-K, filed with the Securities and Exchange Commission on February 22, 2017)
10.23*+	Form of Performance Share Unit Award Agreement for performance share units granted to executive officers in 2018
10.24	Purchase and Sale Agreement, dated June 21, 2016, by and among QEP Energy Company, as purchaser, and RK Petroleum Corp. and various other owners of certain oil and gas properties in the Permian Basin, as sellers (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on July 27, 2016), as amended by the First Amendment to Purchase and Sale Agreement, dated as of September 7, 2016 (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on October 26, 2016), and the Second Amendment to Purchase and Sale Agreement, dated September 14, 2016 (incorporated by reference to Exhibit 1.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on September 19, 2016)
10.25	Purchase and Sale Agreement, dated July 26, 2017, by and between QEP Energy Company, as buyer, and JM Cox Resources, L.P., Alpine Oil Company, and Kelly Cox, collectively as sellers (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed by the Company with the Securities and Exchange Commission on July 26, 2017)

10.26	Purchase and Sale Agreement, dated July 24, 2017, by and between QEP Energy Company, as seller, and Pinedale Energy Partners, LLC, as buyer (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the Company with the Securities and Exchange Commission on July 25, 2017)
10.27+	Separation Agreement, dated as of September 15, 2017, between the Company and Matthew T. Thompson (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q, filed by the Company with the Securities and Exchange Commission on October 25, 2017)
10.28+	Amendment to Long Term Incentive Agreements, dated as of September 15, 2017, between the Company and Matthew T. Thompson (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q, filed by the Company with the Securities and Exchange Commission on October 25, 2017)
10.29*+	Form of Retention Bonus Letter Agreement, dated February 26, 2018, between the Company and each of its executive officers
10.30*+	Form of Severance Compensation Program Letter Agreement, dated February 26, 2018, between the Company and each of its executive officers
10.31*	Letter Agreement, dated February 28, 2018, by and between QEP Resources, Inc. and Elliott Management Corporation
12.1*	Ratio of earnings to fixed charges
21.1*	Subsidiaries of the Company
23.1*	Consent of Independent Registered Public Accounting Firm – PricewaterhouseCoopers LLP
23.2*	Consent of Independent Petroleum Engineers and Geologists – Ryder Scott Company, L.P.
23.3*	Consent of Independent Petroleum Engineers and Geologists – DeGolyer and MacNaughton
24*	Power of Attorney
31.1*	Certification signed by Charles B. Stanley, QEP Resources, Inc., Chairman, President and Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification signed by Richard J. Doleshek, QEP Resources, Inc. Executive Vice President, Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification signed by Charles B. Stanley and Richard J. Doleshek, QEP Resources, Inc. Chairman, President and Chief Executive Officer and Executive Vice President, Chief Financial Officer, respectively, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Qualifications and Report of Independent Petroleum Engineers and Geologists – Ryder Scott Company, L.P.
101.INS**	XBRL Instance Document
101.SCH**	XBRL Schema Document
101.CAL**	XBRL Calculation Linkbase Document
101.LAB**	XBRL Label Linkbase Document
101.PRE**	XBRL Presentation Linkbase Document
101.DEF**	XBRL Definition Linkbase Document

* 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 28, 2018.

QEP RESOURCES, INC.
(Registrant)

/s/ Charles B. Stanley
Charles B. Stanley,
Chairman, 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 28, 2018.

/s/ Charles B. Stanley Charles B. Stanley	Chairman, President and Chief Executive Officer (Principal Executive Officer)
/s/ Richard J. Doleshek Richard J. Doleshek	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Alice B. Ley Alice B. Ley	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)
*Charles B. Stanley	Chairman of the Board; Director
*David Trice	Director
*Julie A. Dill	Director
*M. W. Scoggins	Director
*Mary Shafer Malicki	Director
*Michael J. Minarovic	Director
*Phillips S. Baker, Jr.	Director
*Robert F. Heinemann	Director
*William L. Thacker III	Director
February 28, 2018	*By /s/ Charles B. Stanley Charles B. Stanley, Attorney in Fact