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, 2016

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, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒		Accelerated filer	o
Non-accelerated filer	o	(Do not check if a smaller reporting company)	Smaller reporting company	o

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, 2016): $4,224,248,350.

At January 31, 2017, there were 239,566,263 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 2017 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 Business Ethics and Compliance Policy.

Finally, 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:

- our growth strategies;
- strong liquidity position providing financial flexibility;
- our liquidity and sufficiency of cash flow from operations, cash on hand and, if needed, availability under our revolving credit facility to fund our operations and planned capital expenditures;
- plans and ability to pursue acquisition opportunities;
- our inventory of drilling locations;
- drilling and completion plans and strategies;
- results from planned drilling operations and production operations;
- plans to increase oil and gas production;
- oil exports from and imports to the U.S.;
- payments of dividends;
- estimates of reserves;
- future development costs;
- development of proved undeveloped (PUD) reserves within five years;
- leasehold development and financial capability to continue planned development;
- ability to incur additional indebtedness under our revolving credit facility;
- loss contingencies;
- sufficiency of accruals;
- expectations regarding oil, gas and NGL prices;
- plans to recover or reject ethane from produced natural gas;
- pro forma results for acquired properties;
- impact of lower or higher commodity prices and interest rates;
- the unfunded status of our pension plan;
- volatility of oil, gas and NGL prices and factors impacting such prices;
- impact of global geopolitical and macroeconomic events;
- plans to enter into derivative contracts and the anticipated benefits from our derivative contracts;

- divestitures of assets;
- trucking of products to sales points;
- impact of weather on drilling, completion and production operations;
- need for capital expenditures to address air emission issues;
- amount and allocation of forecasted capital expenditures and plans for funding capital expenditures, operating expenses and working capital requirements;
- adequacy of insurance;
- impact of and compliance with government regulations;
- assumptions regarding equity compensation;
- settlement of performance share units in cash;
- recognition of compensation costs related to equity compensation grants;
- expected contributions to our employee benefit plans;
- employee benefit plan gains or losses;
- the usefulness of Adjusted EBITDA (a non-GAAP financial measure) as a measure of financial performance and adjustments made to net income to arrive at Adjusted EBITDA;
- delays caused by transportation, processing, storage and refining capacity issues;
- fair values and critical accounting estimates, including estimated asset retirement obligations;
- uncertain tax positions;
- unrecognized tax benefits and the realization of those benefits;
- implementation and impact of new accounting pronouncements;
- impact of shutting in wells;
- factors impacting our ability to transport oil and gas;
- potential for asset impairments and impact of impairments on financial statements;
- no expected additional costs of restructurings;
- managing counterparty risk exposure;
- loss of customers;
- outcome and impact of various claims;
- ability to meet delivery and sales commitments;
- impact of our charter and bylaws on a potential takeover;
- inflation and deflation; and
- value of pension plan assets and plans regarding additional contributions to the pension plan.

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;
- 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;
- shortages of oilfield equipment, services and personnel;
- lack of available pipeline, processing and refining capacity;
- processing volumes and pipeline throughput;
- our ability to successfully integrate acquired assets;
- 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 financial 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;
- 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; 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, 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.

proved undeveloped reserves or PUD Proved reserves that are expected to be recovered from new wells or from existing wells where a major expenditure is required for recompletion.

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 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.

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 focused in two regions of the United States: the Northern Region (primarily in North Dakota, Wyoming 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".

Changes 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) reporting segment, excluding the retained ownership of the Haynesville gathering system (Haynesville Gathering), were classified as discontinued operations on the Consolidated Statement of Operations and the Notes accompanying 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 is directly marketing its own oil, gas and NGL production. While QEP will continue 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 Midstream Sale and the termination of marketing agreements to show its financial results without segments. 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 further discussion.

Financial and Operating Highlights

During the year ended December 31, 2016, QEP:

- Reported record oil equivalent reserves of 731.4 MMboe as of December 31, 2016, a 21% increase over 2015;
- Delivered record oil equivalent production of 55.8 MMboe, a 2% increase over 2015;
- Increased oil production to 20.3 MMbbl, a 4% increase over 2015, including a 43% increase in the Permian Basin;
- Reduced lease operating and transportation and other handling expense by $0.52 per Boe compared to the year ended December 31, 2015, to $9.21 per Boe;
- Generated a net loss of $1,245.0 million, or $5.62 per diluted share;
- Reported $626.2 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);
- Incurred capital expenditures (excluding property acquisitions) of $530.1 million, a 48% reduction from 2015;
- Incurred impairment expense of $1,194.3 million, primarily due to lower future commodity prices;
- Issued 60.95 million shares of common stock through two public offerings and received net proceeds of approximately $781.4 million;
- Acquired various oil and gas properties for approximately $645.2 million, of which approximately $590.6 million was related to the 2016 Permian Basin Acquisition (defined below), subject to customary purchase price adjustments; and

- Maintained strong liquidity, including $443.8 million in cash and cash equivalents and no borrowings under its revolving credit facility as of December 31, 2016.

Strategies

We create value for our shareholders through returns-focused growth, superior execution and a low-cost structure. To achieve these objectives we strive to:

- operate in a safe and environmentally responsible manner;
- 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;
- divest of non-core assets;
- maintain an inventory of low-cost, high-margin development projects in resource plays;
- develop the highest-potential areas of the resource plays in which we operate;
- build contiguous acreage positions that drive operating efficiencies;
- be the operator of our assets, whenever possible;
- be the low-cost driller and producer in each area 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.

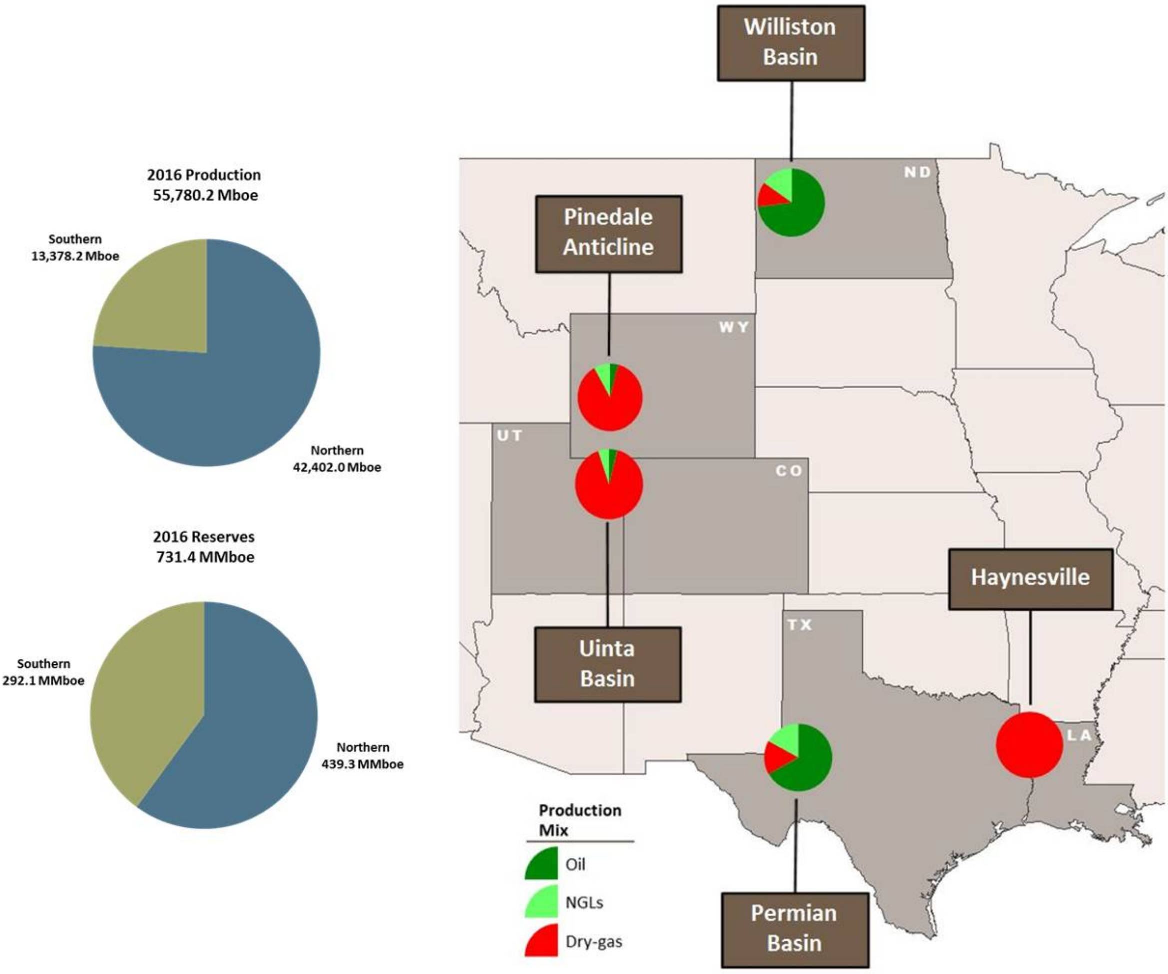
Overview

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 Pinedale Anticline (Pinedale) in western Wyoming, 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 oil and NGL production. Since the beginning of 2012, the Company has made over $3.0 billion of acquisitions of oil-weighted properties and spent approximately 60% of its capital expenditures (excluding property acquisitions) on its oil-weighted properties. During 2016, QEP increased oil production by 4% compared to 2015, and oil and NGL production represented 47% of total production during the year ended December 31, 2016, compared to 45% during the year ended December 31, 2015, and 44% during the year ended December 31, 2014. Additionally, oil and NGL revenue represented approximately two-thirds of total field-level revenues during the three-year period ended December 31, 2016. 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 October 2016, QEP acquired oil and gas properties in the Permian Basin for an aggregate purchase price of approximately $590.6 million, subject to customary purchase price adjustments (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.

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 as of December 31, 2016:



QEP seeks to acquire, develop and produce oil and gas from resource plays in its core operating areas and expand into new areas where it can capitalize on its operating expertise. Since the existence and distribution of hydrocarbons in resource plays is now better understood, developing these accumulations generally has lower risk than developing conventional discrete hydrocarbon accumulations. Resource plays typically require drilling and completing many wells at high density to fully develop and recover the hydrocarbon accumulations. QEP's resource play development requires expertise in drilling and completing a large number of complex, highly deviated or horizontal wells and the application of advanced well completion techniques, including hydraulic fracture stimulation, to achieve economic production rates and recoverable volumes. QEP enters into contracts with various service companies to drill and complete its wells. QEP also conducts exploratory drilling to determine the commercial viability of its unproven leasehold inventory. QEP seeks to maintain geographical and geological diversity with its two regions. The Company may pursue additional acquisitions of producing properties through the purchase of assets or corporate entities in order to further expand its presence in its core areas of operations or to create new core areas. QEP may also divest non-core assets that it believes have limited growth opportunities or no longer fit into its corporate strategy.

QEP sells gas volumes to wholesale marketers, industrial users, local distribution companies and utilities. QEP sells oil and NGL volumes to refiners, marketers 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, 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 with pipelines or midstream providers' processing facilities can impact QEP's production volumes. In cases were QEP's wells are not connected to sales pipelines, the Company will have its products trucked from the well location to ultimate sales point.

Description of Properties

Northern Region

Williston Basin
QEP owns 333.8 net productive 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 infill drilling program targeting the Bakken and Three Forks formations. As of December 31, 2016, QEP had one operated rig drilling in the Williston Basin.

Pinedale
QEP owns 685.0 net productive wells in Pinedale 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 development program, targeting the Lance Pool, which is a tight gas sand reservoir. As of December 31, 2016, QEP had one operated rig drilling in Pinedale.

Uinta Basin
The majority of the Uinta Basin's proved reserves are found in a series of vertically stacked, laterally discontinuous reservoirs. The Company continues to evaluate how to best develop this field through horizontal and vertical development and has a large inventory of remaining future locations. As of December 31, 2016, QEP did not have any operated rigs 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.

Southern Region

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 formations. QEP continues to actively acquire acreage in the basin and in 2016, acquired approximately 26,500 additional net acres. QEP continues to test additional formations and evaluate the appropriate ultimate density of its development program. As of December 31, 2016, QEP had three 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. Production is primarily dry gas and QEP has numerous future locations to fully develop its acreage. In addition, in 2016 the Company began a workover program that has provided positive production results on older, lower rate wells. As of December 31, 2016, QEP did not have any operated rigs drilling in the Haynesville/Cotton Valley area.

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

Reserves

At December 31, 2016 and 2015, QEP's estimated proved reserves were approximately 731.4 MMboe and 603.4 MMboe, respectively, of which 97% and 96%, respectively, were Company operated. Proved developed reserves represented 49% and 58% of the Company's total proved reserves at December 31, 2016 and 2015, respectively, while the remaining reserves were classified as proved undeveloped. All reported reserves are located in the United States. QEP does not have any long-term supply contracts with foreign governments, reserves of equity investees or reserves of subsidiaries with a significant minority interest. QEP's estimated proved reserves are summarized in the table below:

	December 31, 2016				December 31, 2015			
	Oil	**Gas**	**NGL**	**Total[1]**	Oil	Gas [1]	NGL	Total[1]
	(MMbbl)	**(Bcf)**	**(MMbbl)**	**(MMboe)[2]**	(MMbbl)	(Bcf)	(MMbbl)	(MMboe)[2]
Proved developed reserves	**103.2**	**1,309.8**	**35.7**	**357.2**	109.7	1,245.3	34.4	351.6
Proved undeveloped reserves	**135.4**	**1,244.0**	**31.5**	**374.2**	83.4	863.6	24.4	251.8
Total proved reserves	**238.6**	**2,553.8**	**67.2**	**731.4**	193.1	2,108.9	58.8	603.4

(1) Proved reserves include gas reserves that QEP expects to produce and use as field fuel.
(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 production life index for each of the years ended December 31, 2014, through December 31, 2016, are summarized in the table below:

Year Ended December 31,	Year End Reserves (MMboe)	Oil, Gas and NGL Production (MMboe)	Reserve Life Index[1] (Years)
2014	655.3	53.8	12.2
2015	603.4	54.5	11.1
2016	**731.4**	**55.8**	**13.1**

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

Proved Reserves

Reserve 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 15 – 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 major operating areas are summarized in the table below:

	December 31,			
	2016		2015	
Northern Region	(MMboe)	(% of total)	(MMboe)	(% of total)
Williston Basin	**160.2**	**22%**	181.0	30%
Pinedale	**160.7**	**22%**	187.5	31%
Uinta Basin	**106.1**	**14%**	93.1	16%
Other Northern	**12.3**	**2%**	12.4	2%
Southern Region				
Permian Basin	**147.8**	**20%**	62.4	10%
Haynesville/Cotton Valley	**144.3**	**20%**	66.1	11%
Other Southern	**—**	**—%**	0.9	—%
Total proved reserves	**731.4**	**100%**	603.4	100%

Estimates of the quantity of proved reserves increased during 2016, primarily due to the 2016 Permian Basin Acquisition and the results of successful workovers in Haynesville/Cotton Valley.

Proved Undeveloped Reserves

Significant changes to PUD reserves that occurred during 2016 are summarized in the table below:

	2016
	(MMboe)
Proved undeveloped reserves at January 1,	251.8
Transferred to proved developed reserves	**(45.5)**
Revisions to previous estimates[(1)]	**47.3**
Extensions and discoveries[(2)]	**40.5**
Purchase of reserves in place[(3)]	**80.1**
Proved undeveloped reserves at December 31,	**374.2**

(1) Revisions of previous estimates include 51.1 MMboe of positive revisions, primarily related to reserves associated with increased density wells in areas that have been previously developed on lower density spacing and 3.4 MMboe of positive performance revisions. These positive revisions were partially offset by 3.8 MMboe of negative revisions related to pricing, driven by lower oil, gas and NGL prices.

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

(3) Purchase of reserves in place in 2016 was primarily related to the 2016 Permian Basin Acquisition as discussed in Note 2 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K.

The costs incurred to continue the development of PUD reserves were approximately $258.1 million, $490.4 million and $792.9 million for the years ended December 31, 2016, 2015 and 2014, respectively. The costs incurred to continue the development of PUD reserves in 2016 were reduced from historical levels in conjunction with our efforts to reduce drilling and completion activities in 2016 as a result of the commodity price environment. QEP transferred 45.5 MMboe of PUD reserves to proved developed reserves in 2016, some of which was a result of installing additional compression at Pinedale. QEP's PUD to proved developed reserves conversion rate was 18%, 23% and 19% for the years ended December 31, 2016, 2015 and 2014, respectively.

All of QEP's proved undeveloped reserves at December 31, 2016, are scheduled to be developed within five years from the date such locations were initially disclosed as proved undeveloped reserves. QEP estimates that its future development costs relating to the development of PUD reserves are approximately $503.0 million in 2017, $717.3 million in 2018, and $781.3 million in 2019. 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, cash on hand and, if needed, availability under its revolving credit facility will be sufficient to cover these estimated future development costs. PUD reserves related to major development projects will be reclassified to proved developed reserves when production commences.

Internal Controls Over Proved Reserve Estimates, Technical Qualifications and Technologies Used
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, 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 and 2014. RSC prepared approximately 90% and D&M prepared approximately 10% of the Company's total net proved reserves as of December 31, 2015. RSC prepared approximately 91% and D&M prepared approximately 9% of the Company's total net proved reserves as of December 31, 2014.

The individual at RSC who was responsible for overseeing the preparation of QEP's reserve estimates as of December 31, 2016, is a registered Professional Engineer in the State of Colorado and graduated with a Masters of Science degree in Geological Engineering from the University of Missouri at Rolla in 1976. The individual has over 31 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 Corporate Reserves Manager. This individual is a member of the Society of Petroleum Engineers and graduated with a Bachelors of Science degree in Engineering from the University of Minnesota. This individual has over 29 years of experience in the petroleum industry, including 14 years of experience in corporate reserves management.

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 reserves estimates. Performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of historical production data available through late 2016, 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 2016, 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 in 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.

Refer to Note 15 – Supplemental Oil and Gas Information (unaudited) of the Consolidated Financial Statements included 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, 2016, 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.

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, 2016, 2015 and 2014:

	Year Ended December 31,		
	2016	2015	2014
Production volumes			
Oil (Mbbl)	**20,293.8**	19,582.3	17,146.5
Gas (Bcf)	**177.0**	181.1	179.3
NGL (Mbbl)	**5,978.8**	4,704.3	6,769.1
Total equivalent production (Mboe)	**55,780.2**	54,462.1	53,778.9
Total equivalent production (Bcfe)	**334.7**	326.8	322.7
Average field-level price [1]			
Oil (per bbl)	**$ 37.90**	$ 42.59	$ 79.79
Gas (per Mcf)	**$ 2.36**	$ 2.59	$ 4.33
NGL (per bbl)	**$ 13.97**	$ 16.98	$ 32.95
Production costs (per Boe)			
Lease operating expense	**$ 4.03**	$ 4.38	$ 4.46
Oil, gas and NGL transportation and other handling costs	**5.18**	5.35	5.16
Production and property taxes	**1.70**	2.16	3.82
Total production costs	**$ 10.91**	$ 11.89	$ 13.44

(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	
	2016	2015	2014	**2016 vs 2015**	2015 vs 2014
Oil production volumes (Mbbl)					
Northern Region					
Williston Basin	**14,658.6**	14,871.8	13,130.9	**(213.2)**	1,740.9
Pinedale	**670.9**	716.6	632.0	**(45.7)**	84.6
Uinta Basin	**774.2**	848.6	893.3	**(74.4)**	(44.7)
Other Northern	**141.9**	186.5	200.9	**(44.6)**	(14.4)
Southern Region					
Permian Basin	**3,983.9**	2,791.2	1,582.2	**1,192.7**	1,209.0
Haynesville/Cotton Valley	**28.4**	33.6	35.3	**(5.2)**	(1.7)
Other Southern	**35.9**	134.0	671.9	**(98.1)**	(537.9)
Total production	**20,293.8**	19,582.3	17,146.5	**711.5**	2,435.8

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

	Year Ended December 31,			Change	
	2016	2015	2014	**2016 vs 2015**	2015 vs 2014
Gas production volumes (Bcf)					
Northern Region					
Williston Basin	**15.2**	11.3	6.6	**3.9**	4.7
Pinedale	**82.4**	87.5	75.0	**(5.1)**	12.5
Uinta Basin	**22.4**	22.7	17.9	**(0.3)**	4.8
Other Northern	**7.9**	9.4	9.3	**(1.5)**	0.1
Southern Region					
Permian Basin	**5.3**	4.4	3.2	**0.9**	1.2
Haynesville/Cotton Valley	**43.4**	43.2	49.5	**0.2**	(6.3)
Other Southern	**0.4**	2.6	17.8	**(2.2)**	(15.2)
Total production	**177.0**	181.1	179.3	**(4.1)**	1.8

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

	Year Ended December 31,			Change	
	2016	2015	2014	**2016 vs 2015**	2015 vs 2014
NGL production volumes (Mbbl)					
Northern Region					
Williston Basin	**3,182.7**	1,953.4	1,010.5	**1,229.3**	942.9
Pinedale	**1,417.1**	1,528.6	3,350.2	**(111.5)**	(1,821.6)
Uinta Basin	**203.9**	287.6	679.0	**(83.7)**	(391.4)
Other Northern	**22.3**	19.6	14.9	**2.7**	4.7
Southern Region					
Permian Basin	**1,109.9**	815.4	511.0	**294.5**	304.4
Haynesville/Cotton Valley	**28.2**	28.6	37.3	**(0.4)**	(8.7)
Other Southern	**14.7**	71.1	1,166.2	**(56.4)**	(1,095.1)
Total production	**5,978.8**	4,704.3	6,769.1	**1,274.5**	(2,064.8)

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

	Year Ended December 31,			Change	
	2016	2015	2014	**2016 vs 2015**	2015 vs 2014
Total production volumes (Mboe)					
Northern Region					
Williston Basin	**20,370.0**	18,709.6	15,238.2	**1,660.4**	3,471.4
Pinedale	**15,826.0**	16,829.6	16,479.5	**(1,003.6)**	350.1
Uinta Basin	**4,714.3**	4,924.0	4,547.1	**(209.7)**	376.9
Other Northern	**1,491.7**	1,764.1	1,763.5	**(272.4)**	0.6
Southern Region					
Permian Basin	**5,976.7**	4,332.5	2,629.2	**1,644.2**	1,703.3
Haynesville/Cotton Valley	**7,285.5**	7,268.0	8,315.0	**17.5**	(1,047.0)
Other Southern	**116.0**	634.3	4,806.4	**(518.3)**	(4,172.1)
Total production	**55,780.2**	54,462.1	53,778.9	**1,318.1**	683.2

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	
	2016	2015	2014	**2016 vs 2015**	2015 vs 2014
Average field-level oil price (per bbl)					
Northern Region	**$ 36.97**	$ 41.78	$ 78.87	**$ (4.81)**	$ (37.09)
Southern Region	**$ 41.68**	$ 47.16	$ 85.76	**$ (5.48)**	$ (38.60)
Average field-level oil price	**$ 37.90**	$ 42.59	$ 79.79	**$ (4.69)**	$ (37.20)
Average field-level gas price (per Mcf)					
Northern Region	**$ 2.33**	$ 2.58	$ 4.26	**$ (0.25)**	$ (1.68)
Southern Region	**$ 2.42**	$ 2.60	$ 4.44	**$ (0.18)**	$ (1.84)
Average field-level gas price	**$ 2.36**	$ 2.59	$ 4.33	**$ (0.23)**	$ (1.74)
Average field-level NGL price (per bbl)					
Northern Region	**$ 14.50**	$ 18.06	$ 33.22	**$ (3.56)**	$ (15.16)
Southern Region	**$ 11.75**	$ 12.49	$ 32.15	**$ (0.74)**	$ (19.66)
Average field-level NGL price	**$ 13.97**	$ 16.98	$ 32.95	**$ (3.01)**	$ (15.97)
Lease operating and transportation and other handling costs (per Boe)					
Northern Region	**$ 8.71**	$ 8.67	$ 9.08	**$ 0.04**	$ (0.41)
Southern Region	**$ 10.79**	$ 13.41	$ 10.94	**$ (2.62)**	$ 2.47
Average lease operating and transportation and other handling costs	**$ 9.21**	$ 9.73	$ 9.62	**$ (0.52)**	$ 0.11

<u>Northern Region</u>

Williston Basin

Production 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 2015, production increased 23% to 18,709.6 Mboe, compared to 2014, due to increased oil, gas and NGL production. The increase in production volumes was primarily attributable to continued development drilling and completion activity.

During the years ended December 31, 2016, 2015 and 2014, Williston Basin production represented 37%, 34%, and 29%, respectively, of QEP's total production.

Pinedale

Production 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.

Production from Pinedale increased 2% to 16,829.6 Mboe during 2015 compared to 2014. This increase in production volumes was primarily a result of increased gas production due to continued net well completions in 2014 and 2015 and better performing well completions from the new wells drilled in 2015. This increase was mostly offset by a decrease in NGL production due to operating in ethane rejection throughout the majority of 2015 compared to ethane recovery in 2014.

During the year ended December 31, 2016, Pinedale's production represented 28% of QEP's total production, compared to 31% for the years ended December 31, 2015 and 2014, respectively.

Uinta Basin

Production volumes decreased 4% to 4,714.3 Mboe during 2016 compared to 2015, primarily attributable 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.

Production volumes increased 8% to 4,924.0 Mboe during 2015 compared to 2014, primarily due to increased gas production due to new Lower Mesaverde well completions in 2015, partially offset by a decrease in NGL production due to operating in ethane rejection throughout the majority of 2015 compared to ethane recovery in 2014.

During the years ended December 31, 2016, 2015 and 2014, Uinta Basin production represented 8%, 9%, and 8%, respectively, of QEP's total production.

Other Northern
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 2015, production remained flat compared to 2014, due to a slight increase in gas production, primarily from 4.0 net well completions, offset by a slight decrease in oil production.

For each of the three years ended December 31, 2016, 2015 and 2014, Other Northern production represented 3% of QEP's total production.

<u>Southern Region</u>

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

Production from the Permian Basin increased 65% to 4,332.5 Mboe during 2015 compared to 2014, due to increased horizontal well development combined with a full year of production in 2015 related to the 2014 Permian Basin Acquisition compared to 10 months of production in 2014 (see Note 2 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K).

During the years ended December 31, 2016, 2015 and 2014, Permian Basin production represented 11%, 9%, and 5% respectively, of QEP's total production.

Haynesville/Cotton Valley
Production slightly increased during 2016 compared to 2015, due to well workovers and increased non-operated production, partially offset by a natural decline and the continued suspension of QEP's operated drilling program.

During 2015, production volumes decreased 13% to 7,268.0 Mboe compared to 2014, due to natural decline and the continued suspension of QEP's operated drilling program, partially offset by 3.2 net non-operated well completions in 2015.

During the years ended December 31, 2016 and 2015, Haynesville/Cotton Valley's production represented 13% of QEP's total production, compared to 15% for the year ended December 31, 2014.

Other Southern
Production volumes decreased 82% to 116.0 Mboe during 2016 compared to 2015, due to the continued divestitures of non-core properties.

During 2015, production decreased 87% to 634.3 Mboe compared to 2014, due to the continued divestitures of non-core properties.

During the years ended December 31, 2015 and 2014, Other Southern production represented 1%, and 9% of QEP's total production, respectively.

Productive Wells

The following table summarizes the Company's operated and non-operated productive wells as of December 31, 2016, all of which are located in the U.S.:

	Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Northern Region						
Williston Basin	844	333.8	—	—	844	333.8
Pinedale[(1)]	—	—	1,113	685.0	1,113	685.0
Uinta Basin	1,548	195.0	707	522.0	2,255	717.0
Other Northern	43	17.4	473	206.0	516	223.4
Southern Region						
Permian Basin	484	458.3	—	—	484	458.3
Haynesville/Cotton Valley	1	0.1	839	443.0	840	443.1
Other Southern	1	—	58	4.0	59	4.0
Total productive wells	2,921	1,004.6	3,190	1,860.0	6,111	2,864.6

(1) Gross productive wells includes 69 wells in which QEP only owns a small overriding royalty interest.

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, 2016. "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	170,582	114,316	79,117	17,774	249,699	132,090
Kansas	46,433	20,912	35,419	12,765	81,852	33,677
Louisiana	69,740	61,915	1,384	1,531	71,124	63,446
Montana	38,377	15,887	331,925	58,397	370,302	74,284
New Mexico	7,740	4,266	28,611	5,644	36,351	9,910
North Dakota	207,596	69,461	167,190	54,409	374,786	123,870
South Dakota	40	40	203,330	107,551	203,370	107,591
Texas	41,060	31,799	91,865	46,855	132,925	78,654
Utah	203,183	156,483	194,205	117,321	397,388	273,804
Wyoming	245,317	152,962	160,045	99,906	405,362	252,868
Other	15,715	4,547	157,821	43,517	173,536	48,064
Total	1,045,783	632,588	1,450,912	565,670	2,496,695	1,198,258

(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,		
2017	59,175	39,885
2018	45,211	22,155
2019	10,371	8,466
2020	8,950	8,287
2021 and later	7,446	7,289
Total	131,153	86,082

Drilling Activity

The following table summarizes the total number of developmental 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.

	Developmental Wells				Exploratory Wells			
	Productive		Dry		Productive		Dry	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
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	—	—
Year Ended December 31, 2014								
Northern Region								
Williston Basin	199	80.6	—	—	—	—	—	—
Pinedale	116	82.4	—	—	—	—	—	—
Uinta Basin	196	6.5	—	—	—	—	—	—
Other Northern	3	3.0	—	—	1	1.0	—	—
Southern Region								
Permian Basin	71	63.2	—	—	—	—	—	—
Haynesville/Cotton Valley	40	3.2	1.0	0.3	—	—	—	—
Other Southern	32	2.3	—	—	—	—	—	—
Total	657	241.2	1.0	0.3	1	1.0	—	—

The following table presents operated and non-operated well completions for the year ended December 31, 2016:

	Operated Completions		Non-operated Completions	
	Gross	Net	Gross	Net
Northern Region				
Williston Basin	41	37.5	29	2.0
Pinedale	44	24.4	—	—
Uinta Basin	8	8.0	3	0.0
Other Northern	3	3.0	—	—
Southern Region				
Permian Basin	20	19.5	—	—
Haynesville/Cotton Valley	—	—	15	2.6
Other Southern	—	—	—	—

The following table presents operated and non-operated wells drilling and waiting on completion at December 31, 2016:

	Operated				Non-operated			
	Drilling		Waiting on completion		Drilling		Waiting on completion	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Northern Region								
Williston Basin	3	3.0	15	12.8	—	—	14	0.4
Pinedale	6	2.4	8	4.5	—	—	—	—
Uinta Basin	—	—	—	—	—	—	—	—
Other Northern	—	—	—	—	—	—	—	—
Southern Region								
Permian Basin	3	3.0	13	13.0	—	—	—	—
Haynesville/Cotton Valley	—	—	—	—	3	0.5	9	0.9
Other Southern	—	—	—	—	—	—	—	—

QEP typically utilizes multi-well pad drilling where practical. Wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location. QEP sometimes suspends completion activities due to adverse weather conditions, operational factors or other macroeconomic circumstances, such as low commodity prices. QEP had 36 gross operated wells waiting on completion as of December 31, 2016.

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:

	Delivery Commitments
Period	(MMboe)
2017	17.3
2018	1.3
2019	—
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, 2016, the Company did not have a significant amount of production from QEP's owned properties that was subject to priorities, proration or third-party imposed 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 rates. Seasonal anomalies can minimize or exaggerate the impact on these operations, while extreme weather events can materially constrain our operations for a short period of time. In the Pinedale field, QEP typically ceases completion activities of newly drilled wells in the fourth quarter due to adverse weather conditions and resumes completion activity in the first quarter as weather allows. In the Williston Basin, QEP drills and completes wells throughout the year, but adverse weather conditions can impact drilling, completion and production operations.

Significant Customers

QEP's five largest customers accounted for 48%, 30%, and 33%, in the aggregate, of QEP's revenues for the years ended December 31, 2016, 2015 and 2014, respectively. 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. During the year ended December 31, 2014, Valero Marketing & Supply Company accounted for 10% 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.

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 December 31, 2016, QEP had 656 employees compared to 693 employees at December 31, 2015. 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, 2017, are listed below:

Charles B. Stanley	58	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	58	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	53	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	47	Vice President, General Counsel and Corporate Secretary (January 2016 to present). Vice President and General Counsel (2012 to 2016). 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	53	Vice President, Human Resources (2010 to present). Prior to joining QEP, Ms. Fiala held a variety of roles at Suncor Energy (1995 to 2010), including Director of Human Resources.
Matthew T. Thompson	44	Vice President, Energy (2015 to present). Vice President - Northern Region (2013 to 2015). General Manager - High Plains Division (2012 to 2013). General Manager - Legacy Division (2011 to 2012). Reservoir Engineer Manager (2010 to 2011). Previous Titles with Questar Corporation: Manager - Business Development (2009 to 2010); Director of Planning (2006 to 2009).
Alice B. Ley	43	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) and an Audit Manager in the Energy Division of Arthur Anderson, LLP (1996 to 2001).

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. QEP believes that it is in compliance, in all material respects, with currently applicable laws and regulations. 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. 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. 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.

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 Methane 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. The final rule became effective in January 2017 and is the subject of pending litigation filed by oil and gas trade associations and certain states seeking to modify or overturn 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. These regulations took effect in January 2017, although the BLM has delayed one piece of the regulation and is assessing whether to extend other compliance deadlines as well.

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 pollutants into 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 federal Safe Drinking Water Act (SDWA) and comparable state statutes restrict the disposal, treatment, and release of water produced or used during oil and gas development, including via disposal wells.

In June 2015, the EPA and the U.S. Army Corps of Engineers (USACE) issued a final rule intended to clarify the definition of jurisdictional "waters of the United States" regulated under the Clean Water Act. The final rule, which has been stayed pending the outcome of litigation, could change the scope of waters subject to federal regulation under the Clean Water Act.

In January 2017, the USACE also issued revised and renewed nationwide permits (NWPs) that are available to satisfy permitting requirements for 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 of 1899. The new NWPs take effect in March 2017, or when certified by each state, whichever is later. The oil and gas industry currently utilizes NWP 12 and NWP 39 for the construction, maintenance and repairs of pipelines and drill pads, respectively, and related roads and structures in waters of the United States that impact no more than one-half acre of waters of the United States. These two renewed NWPs were not significantly revised from their previous versions, but the states or local USACE offices may impose additional, area-specific restrictions or requirements on these NWPs before they take effect.

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. All wells drilled in tight sand or shale reservoirs require hydraulic fracture stimulation to achieve economic production rates and recoverable reserves. 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, 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.

Currently, all well construction activities, including hydraulic fracture stimulation, are regulated by state agencies that review and approve all aspects of oil and gas well design, construction, and operation. The EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the SDWA and is considering other potential regulation of hydraulic fracturing activities, including pretreatment standards for the oil and gas extraction industry, reporting and disclosure requirements for chemical substances and mixtures used for hydraulic fracturing, and other possible regulations to address the potential effects of hydraulic fracturing on drinking water. QEP does not use diesel fuel in any of its hydraulic fracturing fluids. Additionally, in March 2015, the BLM finalized new regulations, which were to become effective in June 2015, regarding chemical disclosure requirements and other regulations specific to well stimulation activities, including hydraulic fracturing, on federal and tribal leases. These regulations have the potential to increase the cost of drilling and completing any well requiring federal permits and could result in further delays in getting such permits to authorize drilling and completion activities on federal and tribal leases. Several states, including some in which QEP operates, have filed suit against the Department of the Interior over the final BLM hydraulic fracturing regulations. The U.S. District Court for the District of Wyoming set aside the BLM's regulations and the decision is now on appeal to the U.S. Court of Appeals for the Tenth Circuit. Oral argument is currently scheduled for March 2017.

At the state level, some states have adopted and other states are considering adopting regulations that could restrict hydraulic fracturing in certain circumstances. 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 seeks 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. Following an October 2015 response to a petition of ENGOs, the EPA in January 2017 issued proposed rules to add natural gas processing facilities to the list of facilities that must report under EPCRA and is accepting public comment on the proposed rule until March 2017. 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 the Transportation and Sales of Natural Gas

Natural Gas Act of 1938, Natural Gas Policy Act of 1978 and Energy Policy Act of 2005. The FERC regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 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.

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. 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 became effective in January 2017 and requires adoption of American Petroleum Institute Recommended Practices for depleted reservoir storage facilities by January 2018, which is a highly compressed time frame, especially for smaller facilities like the Clear Creek facility.

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 two recent examples of these state regulations.

North Dakota. The North Dakota Industrial Commission (the 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 Commission has 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 will be imposed on certain wells that cannot meet the capture goals.

On December 9, 2014, the Commission issued Commission Order No. 25417 (Order) requiring that crude oil produced in the Bakken Petroleum System be conditioned to remove lighter, volatile hydrocarbons to reduce the vapor pressure of crude oil. The Order was effective April 1, 2015.

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. Although the UDEQ is pursuing the development of a Permit by Rule (PBR) program for future air permitting of most oil and gas activities in order to streamline permitting while protecting air quality, that program may be created only through future rulemaking. Also, Utah’s Governor has 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. That designation, expected to be made in 2017, will result in the lowering of emissions allowed in air permits to be issued by the UDEQ to QEP and other operators.

Other Regulations

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

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 swap dealers and major swap 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. In July 2016, the Department of the Interior's Office of Natural Resources (ONRR) revised its regulations related to the valuation of federal oil and gas produced from onshore and offshore federal leases for royalty purposes. The regulations, which took effect in January 2017, change the requirements for valuing and reporting gas sold under certain contractual arrangements, change the reporting of allowed deductions for gas transportation and processing, and allow the ONRR to decide the value of oil and gas for royalty purposes in certain circumstances, among other changes. An oil and gas trade association filed a lawsuit challenging these regulations in December 2016. In addition, 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.

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 potential long-term 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;
- 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;
- government 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 fuels, including coal, nuclear energy 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 or postpone some of its capital projects;
- 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; 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 it 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, 2016, 2015 and 2014, QEP recorded impairment charges of $1,172.7 million, $39.3 million and $1,041.4 million, respectively, on its proved properties and $17.9 million, $2.0 million and $101.8 million, respectively, on its unproved properties. QEP also recorded goodwill impairment of $3.7 million and $14.3 million during the years ended December 31, 2016 and 2015, respectively. See Part I, Item 8, Note 1 – Summary of Significant Accounting Policies, of this Annual Report on Form 10-K for additional information.

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. 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.

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 2015 and 2016 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 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 the 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;
- title problems;
- equipment malfunctions and/or mechanical failure;
- security breaches, cyber attacks, piracy, or terrorist acts;
- 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; and
- 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.

QEP could incur substantial losses as a result of injury 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 against 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.

If our drilling and completion activities do not meet our anticipated results or we are unable to execute our drilling 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. QEP utilizes multi-well pad drilling where practical. 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 commencement of production, which may cause volatility in QEP’s quarterly operating results.

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 leasehold assets are subject to lease agreements that will expire over the next several years unless production is established on units containing the acreage. Leases on oil and gas properties typically have a 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. If QEP's leases expire and QEP is unable to renew the leases, 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.

SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be classified as proved reserves if they relate to wells scheduled to be drilled within five years after the date of booking. SEC rules require that, subject to limited exceptions, proved undeveloped (PUD) reserves may only be classified as proved reserves if they are from wells scheduled to be drilled within five years after the date of booking. Recovery of PUD reserves requires significant capital expenditures and successful drilling operations. QEP cannot be certain that development will occur as scheduled. QEP may be required to write down its PUD reserves if it does not drill wells within the required five-year time frame.

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 specifically identified and scheduled certain well locations as an estimation of its future multi-year drilling activities on its existing acreage. 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 QEP 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, many midstream companies are attempting to renegotiate their gathering, processing and transportation agreements with their upstream counterparties. 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. For example, an entity that purchases, gathers and processes natural gas produced from oil wells operated by QEP in the Williston Basin claimed during the first half of 2016 that the decline in commodity prices had rendered its gathering and processing operations "uneconomic" and demanded that QEP pay additional fees for gathering and processing services and refused to connect new wells to the gathering system. QEP disputed the entity's claims and commenced arbitration. In November 2016, the parties dismissed the arbitration and entered into a new agreement with an extended term, a revised fee structure and increased capacity. Until the dispute was resolved, QEP experienced delays in completing new wells in the area, which adversely impacted QEP's production and results of operations during 2016.

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, 2016, QEP’s aggregate long-term contractual obligation under these agreements was $680.3 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 obtain needed 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 the Company 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. QEP currently has no borrowings under its unsecured revolving credit facility. In the past, QEP has utilized 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, the Company may use interest rate derivatives to manage the interest rate on a portion of its floating-rate debt. The interest rates for the Company'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 $2.0 billion at December 31, 2016. QEP also has various commitments for leases, drilling contracts, derivative contracts, firm transportation, and purchase obligations for services and products. 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. Additionally, the credit 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 9 – Debt, in Item 8 of Part II of this Annual Report on Form 10-K for additional information regarding the financial covenants and our revolving credit agreement.

A downgrade in QEP's credit rating could negatively impact QEP's cost of and access to capital. As of February 2017, 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 occasional sales of non-core 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. To the extent the Company enters into commodity derivative transactions, it may forgo some or all of the benefits of commodity price increases. Additional financial regulations may change QEP's reporting and margin requirements relating to such instruments. 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.

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 production or gathering 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;
- increased severance and/or other taxes;
- cyber attacks;
- legal challenges or lawsuits;
- negative publicity about QEP;
- disinvestment 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; and
- postponement of federal and state oil and gas lease sales.

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 equity funds 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;
- 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 current business, such as QEP's 2016 Permian Basin Acquisition completed in October 2016. 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:

- 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 indirectly limit QEP’s ability to engage in acquisitions.

QEP may be unable to dispose of non-core, non-strategic assets on financially attractive terms, resulting in reduced cash proceeds. QEP's business strategy also includes sales of non-core, non-strategic assets. QEP continually evaluates its portfolio of assets related to capital investments, divestitures and joint venture opportunities. 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 commodity prices, laws, regulations and the permitting process 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. Inability to achieve a desired price for assets, or underestimation of amounts of retained liabilities or indemnification obligations, can result in a reduction of cash proceeds, a loss on sale due to an excess of the asset's net book value over proceeds, or liabilities that must be settled in the future at amounts that are higher than QEP had expected.

QEP is involved in legal proceedings that may result in substantial liabilities. 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, which could materially and adversely impact the Company's cash flows and operating results for a particular period. 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.

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.

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. The 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 wells. 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.

In June 2016, the EPA also 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 non-attainment. 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 marginal nonattainment area for ozone. The proposals will likely result in increased operating and compliance costs.

In November 2016, the EPA also issued a final Information Collection Request (ICR) to QEP and its competitors in the oil and gas industry to support development of new regulations covering methane emissions at existing oil and gas sites. This process could result in additional regulations on existing oil and gas sites potentially leading to increased operating and compliance costs.

The FERC has jurisdiction over the operation of QEP's Clear Creek underground gas storage facility by virtue of the facility's connection to interstate pipelines (also subject to FERC jurisdiction) at both its inlet and outlet. 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.

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 North Dakota Industrial 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 will 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, the BLM has recently finalized a new rule related to further controls on the venting and flaring of natural gas on BLM and tribal leases. The BLM venting and flaring rule is the subject of active litigation in the U.S. District Court for the District of Wyoming. These gas capture requirements, and any similar future obligations in North Dakota or our other locations, may increase our operational costs or restrict our production, which could materially and adversely affect our financial condition, results of operations and cash flows.

New rules regarding crude oil shipments by rail may pose unique hazards that may have an adverse effect on our operations. In December 2014, the North Dakota Industrial Commission issued Commission Order No. 25417 requiring that crude oil produced in the Bakken Petroleum System be conditioned to remove lighter, volatile hydrocarbons to improve the marketability and safe transportation of the crude oil. The Commission’s order was effective April 1, 2015. In May 2015, the U.S. Department of Transportation issued its 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. 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.

Current federal regulations restrict activities during certain times of the year on significant portions of QEP leasehold due to wildlife activity and/or habitat. QEP has worked with federal and state officials in Wyoming to obtain authorization for limited winter drilling activities in Pinedale and has developed measures, such as drilling multiple wells from a single pad location, to minimize the impact of its activities on wildlife and wildlife habitat in its operations on federal lands. Many of QEP's operations are subject to the requirements of NEPA, and are therefore evaluated under NEPA for their direct, indirect and cumulative environmental impacts. This is done in Environmental Assessments or Environmental Impact Statements prepared for a lead agency under Council on Environmental Quality and other agency regulations, usually for the BLM in the areas where QEP operates currently. In September 2008, the BLM issued a Record of Decision (ROD) on the Final Supplemental Environmental Impact Statement (FSEIS) for long-term development of gas resources in the Pinedale Anticline Project Area (PAPA). Under the ROD, QEP is allowed to drill and complete wells year-round in one of five Concentrated Development Areas.

As a result of future legislation, certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated and our production may be subject to the imposition of new U.S. federal taxes. The U.S. President's Fiscal Year 2017 Budget Proposal (proposed by former President Obama in February 2016) and legislation introduced in a prior session of Congress include proposals that, if enacted into law, would eliminate certain key U.S. federal income tax provisions currently available to oil and gas exploration and production companies or potentially make our operations subject to the imposition of new U.S. federal taxes. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, (iv) an extension of the amortization period for certain geological and geophysical expenditures and (v) imposition of a $10.25 per barrel fee on oil, to be paid by oil companies (but the budget does not describe where and how such a fee would be collected). It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change, as well as any changes to or the imposition of new U.S. federal, state or local taxes (including the imposition of, or increase in production, severance or similar taxes), could increase the cost of exploration and development of oil and gas resources, which would negatively affect our financial condition and results of operations.

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. For example, QEP's operations on tribal lands within the Williston Basin in North Dakota and Vermillion Basin in Wyoming continue to be delayed due to the substantial backlog of permit applications and backlog of environmental reviews. 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 all aspects of 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 appears to be considering its existing regulatory authorities for possible avenues to further regulate hydraulic fracturing fluids and/or the components of those fluids. Additionally, the BLM finalized regulations in March 2015 regarding chemical disclosure requirements and other regulations specific to well stimulation activities, including hydraulic fracturing, on federal and tribal leases; however, the rules were set aside by the U.S. District Court for the District of Wyoming. The district court’s decision has been appealed to the U.S. Court of Appeals for the Tenth Circuit. If held to be valid, the new regulations will increase the cost of drilling and completing any well requiring federal permits and could result in further delays in getting such permits to authorize drilling and completion activities on federal and tribal leases upon which QEP operates.

At the state level, some states have adopted and other states are considering adopting regulations that could restrict hydraulic fracturing in certain circumstances. 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.

The EPA has been collecting information as part of a nationwide study into the effects of hydraulic fracturing on drinking water. In December 2016, the EPA released its final report on the potential impacts to drinking water resources from hydraulic fracturing. The results of this study, which concludes that hydraulic fracturing activities can impact drinking water resources under some circumstances, could result in additional regulations, which could lead to operational burdens similar to those described above. The EPA has also issued an advance notice of proposed rulemaking and initiated a public participation process under the Toxic Substances Control Act to seek comment on the information that should be reported or disclosed for hydraulic fracturing chemical substances and mixtures and the mechanisms for obtaining this information. Additionally, in January 2017, the EPA issued proposed rules to add natural gas processing facilities to the list of facilities that must report releases of certain "toxic chemicals" to the environment, including permitted releases, under the Toxics Release Inventory program of the EPCRA and is accepting public comment on the proposed rule until March 2017.

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 recently 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 in other states, including recently in Oklahoma, 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 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 and services, reducing the demand for and consumption of our products and services (due to change in both costs and weather patterns) and the economic health of the regions in which we operate, all of which can create financial risks. In addition, legislative and regulatory responses related to GHG emissions and climate change may result in increased operating costs, delays in obtaining air pollution 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 development. Federal, state and local governments may also pass laws mandating the use of alternative energy sources, such as wind power and solar energy, which may reduce demand for oil and natural gas. QEP's ability to access and develop new oil and gas reserves may be restricted by climate change regulation, including GHG reporting and regulation. Congress has previously considered proposed legislation aimed at reducing GHG emissions. The EPA has adopted final regulations 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 emissions from oil and natural gas facilities. In June 2014, the United States Supreme Court's holding in Utility Air Regulatory Group v. EPA upheld a portion of EPA's GHG stationary source permitting program, but also invalidated a portion of it. Upon remand, the EPA is considering how to implement the Court's decision. The Court's holding does not prevent states from considering and adopting state-only major source permitting requirements based solely on GHG emission levels.

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. The steady cutbacks in carbon emissions set forth in the Paris Agreement could adversely impact our business by limiting our ability to develop new oil and gas reserves, reducing the value of our assets and decreasing the price of our common stock.

In addition, 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.

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.

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 a requirement that certain transactions be cleared on exchanges. 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 is ongoing and the ultimate effect of the adopted rules and regulations and any future rules and regulations on QEP's business remains uncertain.

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; assumptions used in business combinations; weather and natural disasters; changes in customers' credit ratings; competition from other forms of energy, other pipelines 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 41 active and suspended participants, or 6%, of QEP's active employees and 173 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, 2016 and 2015, QEP's pension plans were underfunded by $43.1 million and $41.0 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 $7.2 million and $7.5 million during the years ended December 31, 2016 and 2015, respectively, to the Pension Plan and SERP and expects to make contributions of approximately $6.5 million to these pension plans in 2017. 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 cyber attacks 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's systems and insurance coverage 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 vulnerability to cyber incidents. QEP does not maintain specialized insurance for possible liability resulting from a cyber attack on its assets that may shut down all or part of QEP's business.

While QEP has experienced cyber attacks, QEP is not aware of any material losses relating to cyber attacks; 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 2016, QEP issued a total of 60.95 million shares of its common stock in two separate underwritten public offerings. In the future, QEP may issue additional 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. QEP timely responded to the information requests. In August 2016, the EPA requested a conference to review this matter. In addition, since February 2016, the North Dakota Department of Health (NDDH) has engaged with the oil and gas production industry in North Dakota to address potential noncompliance associated with emissions from tank batteries. QEP has participated in these discussions. While no formal federal or state enforcement action has been commenced in connection with the tank batteries to date, QEP anticipates that resolution of these matters will likely result in monetary penalties and require QEP to incur additional capital expenditures to correct noncompliance 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.

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, 2017, QEP had 5,585 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 2016 and 2015:

	High price	Low price	Dividend
		(per share)	
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			**$ —**
2015			
First quarter	$ 23.21	$ 18.29	$ 0.02
Second quarter	24.04	18.11	0.02
Third quarter	18.59	11.20	0.02
Fourth quarter	16.95	11.03	0.02
Total			$ 0.08

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 2016, QEP made changes to its peer group to remove Concho Resources, Inc., Denbury Resources, Inc., Sandridge Energy, Inc. and Ultra Petroleum Corporation due to financial characteristics that became dissimilar, and in some cases, bankruptcy. Carrizo Oil & Gas, Inc., Diamondback Energy, Inc., Energen Corporation, EP Energy Corporation, Parsley Energy, Inc., PDC Energy, Inc. and RSP Permian, Inc. were added to QEP's peer group, which is comprised of U.S. companies with similar size and scope to QEP.

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

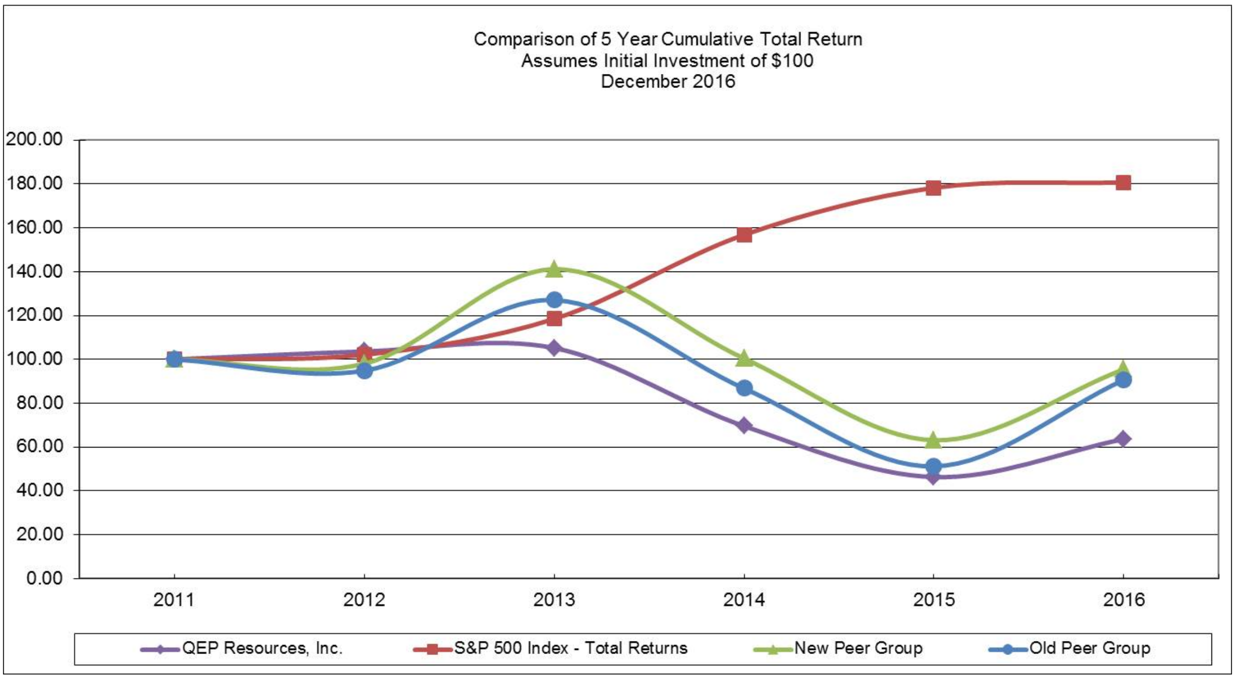
Cabot Oil & Gas Corporation	Range Resources Corporation
Cimarex Energy Company	Sandridge Energy, Inc.
Concho Resources, Inc.	SM Energy Company
Denbury Resources, Inc.	Southwestern Energy Company
Laredo Petroleum, Inc.	Ultra Petroleum Corporation
Newfield Exploration Company	Whiting Petroleum Corporation
Oasis Petroleum, Inc.	WPX Energy, Inc.

After the change in peer companies, QEP's 2016 peer group consisted of the following:

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.	

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, 2011, and its relative performance is tracked through December 31, 2016;
- 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.



	2011		2012		2013		2014		2015		2016	
QEP Resources, Inc.	$	100.00	$	103.61	$	105.19	$	69.58	$	46.33	$	63.65
S&P 500 Index – Total Returns	$	100.00	$	102.11	$	118.45	$	156.82	$	178.28	$	180.75
New Peer Group	$	100.00	$	98.03	$	141.16	$	100.42	$	63.12	$	95.48
Old Peer Group	$	100.00	$	94.84	$	127.06	$	86.76	$	51.20	$	90.64

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, 2016 – October 31, 2016	—	$ —	—	$ —
November 1, 2016 – November 30, 2016	1,892	$ 16.11	—	$ —
December 1, 2016 – December 31, 2016	—	$ —	—	$ —

(1) All of the shares purchased during the three-month period ended December 31, 2016, were acquired from employees in connection with the settlement of income tax and related benefit withholding obligations arising from vesting of restricted stock grants.

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data for the five years ended December 31, 2016, is provided in the table below. Our financial results for the years ended December 31, 2014, 2013 and 2012 have been recast, in accordance with GAAP, to reflect the impact of the sale of substantially all of QEP's midstream business (see footnote (4) to the table below). Refer to Items 7 and 8 in Part II of this Annual Report on Form 10-K for further discussion of the factors affecting the comparability of the Company's financial data.

	Year Ended December 31,				
	2016[1][2]	2015[2]	2014[2]	2013	2012
Results of Operations	(in millions, except per share amounts)				
Revenues[3]	**$ 1,377.1**	$ 2,018.6	$ 3,293.2	$ 2,685.1	$ 2,071.7
Operating income (loss)	**(1,602.6)**	(377.6)	(847.3)	203.0	(321.2)
Income (loss) from continuing operations	**(1,245.0)**	(149.4)	(409.5)	52.1	2.4
Net income from discontinued operations, net of income tax[4]	**—**	—	1,193.9	107.3	125.9
Net income (loss)	**(1,245.0)**	(149.4)	784.4	159.4	128.3
Earnings (loss) per common share					
Basic from continuing operations	**$ (5.62)**	$ (0.85)	$ (2.28)	$ 0.29	$ 0.01
Basic from discontinued operations[4]	**—**	—	6.64	0.60	0.71
Basic total	**$ (5.62)**	$ (0.85)	$ 4.36	$ 0.89	$ 0.72
Diluted from continuing operations	**$ (5.62)**	$ (0.85)	$ (2.28)	$ 0.29	$ 0.01
Diluted from discontinued operations[4]	**—**	—	6.64	0.60	0.71
Diluted total	**$ (5.62)**	$ (0.85)	$ 4.36	$ 0.89	$ 0.72
Weighted-average common shares outstanding					
Used in basic calculation	**221.7**	176.6	179.8	179.2	177.8
Used in diluted calculation	**221.7**	176.6	179.8	179.5	178.7
Dividends per common share	**$ —**	$ 0.08	$ 0.08	$ 0.08	$ 0.08
Financial Position					
Total Assets at December 31,	**$ 7,245.4**	$ 8,398.2	$ 9,256.4	$ 9,380.4	$ 9,074.5
Capitalization at December 31,					
Long-term debt	**2,020.9**	2,191.5	2,187.7	2,969.0	3,172.9
Total equity	**3,502.7**	3,947.9	4,075.3	3,876.8	3,313.7
Total Capitalization	**$ 5,523.6**	$ 6,139.4	$ 6,263.0	$ 6,845.8	$ 6,486.6
Cash Flow From Operations					
Net cash provided by (used in) operating activities	**$ 663.7**	$ 481.3	$ 1,542.5	$ 1,191.7	$ 1,296.0
Capital expenditures	**(1,208.1)**	(1,239.4)	(2,726.4)	(1,602.6)	(2,799.7)
Net cash provided by (used in) investing activities	**(1,179.1)**	(1,217.6)	578.2	(1,441.5)	(2,794.5)
Net cash provided by (used in) financing activities	**583.1**	(47.7)	(990.6)	279.8	1,498.5
Non-GAAP Measure					
Adjusted EBITDA[5]	**$ 626.2**	$ 1,029.3	$ 1,582.7	$ 1,536.7	$ 1,409.0

(1) During the year ended December 31, 2016, the results are impacted by the 2016 Permian Basin Acquisition, which occurred in October 2016. See Note 2 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K for detailed information on the 2016 Permian Basin Acquisition.

(2) During the years ended December 31, 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. See Note 2 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K for detailed information on the 2014 Permian Basin Acquisition and property divestitures.

(3) 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.

(4) 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, 2013 and 2012, have been reclassified.

(5) 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 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,				
	2016	2015	2014	2013	2012
	(in millions)				
Net income (loss)	**$ (1,245.0)**	$ (149.4)	$ 784.4	$ 159.4	$ 128.3
Net income from discontinued operations, net of tax	**—**	—	(1,193.9)	(107.3)	(125.9)
Net income (loss) from continuing operations	**(1,245.0)**	(149.4)	(409.5)	52.1	2.4
Interest expense	**143.2**	145.6	169.1	165.1	126.3
Interest and other (income) expense	**(25.6)**	(3.0)	(12.8)	(15.2)	(15.0)
Income tax provision (benefit)	**(708.2)**	(93.6)	(232.5)	60.1	(1.9)
Depreciation, depletion and amortization	**871.1**	881.1	994.7	963.8	850.2
Unrealized (gains) losses on derivative contracts	**367.0**	183.7	(374.4)	88.7	(63.2)
Exploration expenses	**1.7**	2.7	9.9	11.9	11.2
Net (gain) loss from asset sales	**(5.0)**	(4.6)	148.6	(103.5)	(1.2)
Impairment	**1,194.3**	55.6	1,143.2	93.0	133.0
Other (1)	**32.7**	11.2	2.0	—	115.6
Adjusted EBITDA from continuing operations	**626.2**	1,029.3	1,438.3	1,316.0	1,157.4
Adjusted EBITDA from discontinued operations	**—**	—	144.4	220.7	251.6
Adjusted EBITDA	**$ 626.2**	$ 1,029.3	$ 1,582.7	$ 1,536.7	$ 1,409.0

(1) Reflects legal expenses and loss contingencies incurred during the year ended December 31, 2016, a non-cash pension curtailment loss incurred during the year ended December 31, 2015, a loss from early extinguishment of debt incurred during the year ended December 31, 2014, and a loss from early extinguishment of debt and legal expenses related to class action lawsuit incurred during the year ended December 31, 2012. 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 2015 Annual Report on Form 10-K filing, and analyzes the changes in the results of operations between the years ended December 31, 2016 and 2015, and between the years ended December 31, 2015 and 2014.

OVERVIEW

QEP Resources, Inc. is an independent crude oil and natural gas exploration and production company focused in two regions of the United States: the Northern Region (primarily in North Dakota, Wyoming 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".

The Company has substantial acreage positions and operations in some of the most prolific hydrocarbon resource plays in the continental United States, including the Williston Basin, Permian Basin, Pinedale Anticline, Uinta Basin and Haynesville Shale. These resource plays are characterized by unconventional oil or gas accumulations in continuous tight sands, carbonates or shales that underlie broad geographic areas. The lateral continuity of such resource plays means that, aside from wells abandoned due to mechanical issues, the Company does not expect to drill many unsuccessful wells as it develops these resource plays. Resource plays allow the Company the opportunity to gain considerable operational efficiencies through high-density, repeatable drilling and completion operations. The Company believes it has a large inventory of lower-risk, predictable development drilling locations across its acreage holdings in the onshore U.S., which provide a solid base for growth in organic production and reserves.

While historically the Company has been more natural gas weighted, in recent years the Company has increased its focus on growing oil and NGL production. Since the beginning of 2012, the Company has made over $3.0 billion of acquisitions of oil-weighted properties and spent approximately 60% of its capital expenditures (excluding property acquisitions) on its oil-weighted properties. During 2016, QEP increased oil production by 4% compared to 2015, and oil and NGL production represented 47% of total production during the year ended December 31, 2016, compared to 45% during the year ended December 31, 2015, and 44% during the year ended December 31, 2014. Additionally, oil and NGL revenue represented approximately two-thirds of total field-level revenues during the three-year period ended December 31, 2016.

Equity Offerings

In June 2016, QEP issued 23.0 million shares of common stock through a public offering and received net proceeds of approximately $412.9 million. In October 2016, QEP used the net proceeds from this offering to partially fund the 2016 Permian Basin Acquisition (see Note 2 – Acquisitions and Divestitures in Item 8 of Part II of this Annual Report on Form 10-K for additional information).

In March 2016, QEP issued 37.95 million shares of common stock through a public offering and received net proceeds of approximately $368.5 million. QEP used the net proceeds from this offering for general corporate purposes.

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 on the Consolidated Statement of Operations and the Notes accompanying the Consolidated Financial Statements.

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 Energy is directly marketing its own oil, gas and NGL production. While QEP will continue 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 Midstream Sale and the termination of marketing agreements to show its financial results without segments.

Acquisitions

In October 2016, QEP acquired oil and gas properties in the Permian Basin for an aggregate purchase price of approximately $590.6 million, subject to customary purchase price adjustments (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 the June 2016 equity offering and cash on hand. 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, subject to customary purchase price adjustments, 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.

In February 2014, QEP acquired oil and gas properties in the Permian Basin for an aggregate purchase price of $941.8 million (the 2014 Permian Basin Acquisition). The acquired properties consisted of approximately 26,500 net acres of producing and undeveloped oil and gas properties and approximately 270 vertical producing wells in the Permian Basin. In addition to the 2014 Permian Basin Acquisition, QEP acquired various oil and gas properties in 2014, primarily in the Other Northern area and the Uinta Basin, for a total purchase price of $18.7 million, which included acquisitions of additional interests in QEP operated wells and additional undeveloped leasehold acreage.

While QEP believes its extensive inventory of identified drilling locations provide a solid base for growth in production and reserves, the Company continues to evaluate acquisition opportunities that it believes will create significant long-term value. QEP believes that its experience, expertise and presence in its core operating areas, combined with a low-cost operating model and financial strength, enhances its ability to pursue acquisition opportunities.

Divestitures

The Company periodically divests select non-core assets. 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. In 2014, QEP sold its interest in certain non-core properties in the Other Southern area and the Williston Basin for aggregate proceeds of approximately $783.8 million.

Financial and Operating Highlights

During the year ended December 31, 2016, QEP:

- Reported record oil equivalent reserves of 731.4 MMboe as of December 31, 2016, a 21% increase over 2015;
- Delivered record oil equivalent production of 55.8 MMboe, a 2% increase over 2015;
- Increased oil production to 20.3 MMbbl, a 4% increase over 2015, including a 43% increase in the Permian Basin;
- Reduced lease operating and transportation and other handling expense by $0.52 per Boe compared to the year ended December 31, 2015, to $9.21 per Boe;
- Generated a net loss of $1,245.0 million, or $5.62 per diluted share;
- Reported $626.2 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);

- Incurred capital expenditures (excluding property acquisitions) of $530.1 million, a 48% reduction from 2015;
- Incurred impairment expense of $1,194.3 million, primarily due to lower future commodity prices;
- Issued 60.95 million shares of common stock through two public offerings and received net proceeds of approximately $781.4 million;
- Acquired various oil and gas properties for approximately $645.2 million, of which approximately $590.6 million was related to the 2016 Permian Basin Acquisition, subject to customary purchase price adjustments; and
- Maintained strong liquidity, including $443.8 million in cash and cash equivalents and no borrowings under its revolving credit facility as of December 31, 2016.

Outlook

During 2015 and 2016, we worked to position QEP to increase production, reduce operating and capital costs and improve operating results in a lower commodity price environment. We believe our strong balance sheet will allow us to grow oil production, primarily in the Permian Basin, and gas production during 2017, without the need to incur incremental indebtedness. We remain focused on continuing to grow our oil assets both organically and through acquisitions.

Based on current commodity prices, we expect to be able to fund our planned capital program with cash on hand and cash flow from operating activities. Our total capital expenditures for 2017 are expected to be approximately $975.0 million (excluding property acquisitions), an increase of approximately 80% from 2016 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, 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, level of expenditures for the development of our oil and gas reserves and the price of our common stock 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, 2016, and plans to reject ethane during 2017.

Global Geopolitical and Macroeconomic Factors
QEP continues to monitor the global economy, including Europe's economic outlook and the impact of United Kingdom's vote to exit the European Union; the Organization of Petroleum Exporting Countries (OPEC) countries oil production; political unrest in Europe, the Middle East, and Africa; slowing growth in Asia, particularly in China; actions taken by Congress and the president; 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 crude 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 increased global economic uncertainty and the corresponding volatility of commodity prices, QEP maintained a strong liquidity position to ensure its financial flexibility while reducing drilling and completion activity and planned capital expenditures in 2016. 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, 2016, assuming forecasted 2017 annual production of approximately 58.5 MMboe, QEP had approximately 63% of its forecasted oil production and 73% of its forecasted gas production covered with fixed-price swaps and collars. The average swap prices for the derivative contracts settling in 2016, 2017 and 2018 are significantly lower than the average swap prices for the derivative contracts settled prior to 2016 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 Asset Impairments
The carrying value of the Company's properties is sensitive to declines in oil, gas and NGL prices. These assets are at risk of impairment if future prices for oil, gas or NGL decline and/or drilling and completion costs increase. The cash flow model that the Company uses to assess proved properties for impairment includes numerous assumptions, such as management's estimates of future oil, gas and NGL production, market outlook on forward commodity prices, operating and development costs, and discount rates. All inputs to the cash flow model must be evaluated at each date of estimate.

During the year ended December 31, 2016, the Company recorded impairments of $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. During the year ended December 31, 2014, impairments were $1,143.2 million primarily due to impairments of proved properties in Haynesville/Cotton Valley and the Permian Basin 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.

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. 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 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.

Midstream Services

QEP's ability to produce its wells depends in substantial part on the availability and capacity of gathering, transportation and gas processing facilities owned and operated by third parties. Due to market conditions, many midstream companies are attempting to renegotiate their gathering, processing and transportation agreements with their upstream counterparties. Renegotiation of terms may in the future result in lower revenues, higher costs and longer-term contracts. For example, an entity that purchases, gathers and processes natural gas produced from oil wells operated by QEP in the Williston Basin claimed during the first half of 2016 that the decline in commodity prices had rendered its gathering and processing operations "uneconomic" and demanded that QEP pay additional fees for gathering and processing services and refused to connect new wells to the gathering system. QEP disputed the entity's claims and commenced arbitration. In November 2016, the parties dismissed the arbitration and entered into a new agreement with an extended term, a revised fee structure and increased capacity. Until the dispute was resolved, QEP experienced delays in completing new wells in the area, which adversely impacted QEP's production and results of operations during 2016.

Uncertainties Related to Claims

QEP is currently subject to claims that could adversely impact QEP's liquidity, operating results and capital expenditures for a particular reporting period, including, but not limited to, claims of former limited partners regarding distributions, a Department of Interior Investigation regarding timely payment of Indian royalties and claims regarding potential noncompliance associated with air emissions in the Williston Basin, each of which is described more fully in Note 10 – Commitments and Contingencies, in Item 8 of Part II of this Annual Report on Form 10-K. Given the uncertainties involved in these matters, QEP is unable to predict the ultimate outcomes.

RESULTS OF OPERATIONS

QEP's continuing operations consist of exploration and production activities in several of North America's most important hydrocarbon resource plays. The tables below set forth selected operating data for the periods indicated. Our financial results for 2014 have been revised, in accordance with GAAP, to reflect the impact of the Midstream Sale. See Note 3 – Discontinued Operations, in Item 8 of Part II of this Annual Report on Form 10-K for additional information on the Midstream Sale.

Net Income

QEP generated a net loss from continuing operations during the year ended December 31, 2016, of $1,245.0 million, or $5.62 per diluted share, compared to a net loss from continuing operations 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 derivative losses and a 10% increase in general and administrative expenses. 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.

QEP generated a net loss from continuing operations during the year ended December 31, 2015, of $149.4 million, or $0.85 per diluted share, compared to a net loss from continuing operations of $409.5 million, or $2.28 per diluted share, in 2014. The decrease in net loss for the year ended December 31, 2015 compared to the year ended December 31, 2014, was primarily due to a decrease in impairment expense of $1,087.6 million, a 14% increase in oil production, a slight increase in gas production, a net gain from asset sales of $4.6 million during 2015 compared to a net loss from asset sales of $148.6 million during 2014, a 43% decrease in production and property taxes and an 11% decrease in general and administrative expense. These changes were partially offset by a $558.1 million increase in unrealized losses on derivative contracts, a 23% decrease in average realized prices and a 31% decrease in NGL production.

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 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,		
	2016	2015	2014
	(in millions)		
Net income (loss)	**$ (1,245.0)**	$ (149.4)	$ 784.4
Net income from discontinued operations, net of tax	—	—	(1,193.9)
Net income (loss) from continuing operations	**(1,245.0)**	(149.4)	(409.5)
Interest expense	**143.2**	145.6	169.1
Interest and other (income) expense	**(25.6)**	(3.0)	(12.8)
Income tax provision (benefit)	**(708.2)**	(93.6)	(232.5)
Depreciation, depletion and amortization	**871.1**	881.1	994.7
Unrealized (gains) losses on derivative contracts	**367.0**	183.7	(374.4)
Exploration expenses	**1.7**	2.7	9.9
Net (gain) loss from asset sales	**(5.0)**	(4.6)	148.6
Impairment	**1,194.3**	55.6	1,143.2
Other [(1)]	**32.7**	11.2	2.0
Adjusted EBITDA from continuing operations	**626.2**	1,029.3	1,438.3
Adjusted EBITDA from discontinued operations	—	—	144.4
Adjusted EBITDA	**$ 626.2**	$ 1,029.3	$ 1,582.7

(1) Reflects legal expenses and loss contingencies incurred during the year ended December 31, 2016, a non-cash pension curtailment loss incurred during the year ended December 31, 2015, and a loss from early extinguishment of debt incurred during the year ended December 31, 2014. 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 from continuing operations decreased to $626.2 million during the year ended December 31, 2016, compared to $1,029.3 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.

Adjusted EBITDA from continuing operations decreased to $1,029.3 million during the year ended December 31, 2015, compared to $1,438.3 million in 2014, due to a 23% decrease in average realized prices and a 31% decrease in NGL production, partially offset by a 14% increase in oil production and a slight increase in gas production.

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, 2016 compared to the years ended December 31, 2015 and 2014:

	Oil	Gas	NGL	Total
Production revenues	(in millions)			
Year ended December 31, 2014	$ 1,368.5	$ 776.4	$ 223.3	$ 2,368.2
Changes associated with volumes [1]	194.3	7.8	(68.1)	134.0
Changes associated with prices [2]	(728.6)	(315.7)	(75.2)	(1,119.5)
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**

[1] The revenue variance attributed to the change in volume is calculated by multiplying the change in volumes from the years ended December 31, 2016 and 2015, as compared to the years ended December 31, 2015 and 2014, by the average field-level price for the years ended December 31, 2015 and 2014.

[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, 2016 and 2015, as compared to the years ended December 31, 2015 and 2014, by the respective volumes for the years ended December 31, 2016 and 2015. 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	
	2016	2015	2014	**2016 vs 2015**	2015 vs 2014
Oil (per bbl)					
Average field-level price	**$ 37.90**	$ 42.59	$ 79.79	**$ (4.69)**	$ (37.20)
Commodity derivative impact	**4.25**	18.06	0.92	**(13.81)**	17.14
Net realized price	**$ 42.15**	$ 60.65	$ 80.71	**$ (18.50)**	$ (20.06)
Gas (per Mcf)					
Average field-level price	**$ 2.36**	$ 2.59	$ 4.33	**$ (0.23)**	$ (1.74)
Commodity derivative impact	**0.25**	0.57	(0.09)	**(0.32)**	0.66
Net realized price	**$ 2.61**	$ 3.16	$ 4.24	**$ (0.55)**	$ (1.08)
NGL (per bbl)					
Average field-level price	**$ 13.97**	$ 16.98	$ 32.95	**$ (3.01)**	$ (15.97)
Commodity derivative impact	**—**	—	—	**—**	—
Net realized price	**$ 13.97**	$ 16.98	$ 32.95	**$ (3.01)**	$ (15.97)
Average net equivalent price (per Boe)					
Average field-level price	**$ 22.76**	$ 25.38	$ 44.03	**$ (2.62)**	$ (18.65)
Commodity derivative impact	**2.35**	8.39	(0.02)	**(6.04)**	8.41
Net realized price	**$ 25.11**	$ 33.77	$ 44.01	**$ (8.66)**	$ (10.24)

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 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 non-core 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 NGL 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.

December 31, 2015 compared to December 31, 2014

Oil sales. Oil sales were $834.2 million for the year ended December 31, 2015, a decrease of $534.3 million, or 39%, compared to 2014. This decrease was a result of a 47% decrease in average field-level oil prices, partially offset by a 14% increase in oil production. 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 increase in oil production volumes was primarily driven by an increase in the Williston Basin production due to continued development drilling. The Company also increased production by 76% in the Permian Basin due to continued horizontal development of the area combined with a full year of production in 2015 compared to 10 months of production in 2014. These production increases were partially offset by a production decrease in the Other Southern area due to the divestiture of non-core properties in the second and fourth quarters of 2014.

Gas sales. Gas sales were $468.5 million for the year ended December 31, 2015, a decrease of $307.9 million, or 40%, compared to 2014. This decrease was a result of a 40% decrease in average field-level prices, partially offset by a 1% increase in gas production. 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 increase in production volumes was primarily driven by increased production in Pinedale due to continued net well completions in 2014 and 2015 and higher performing well completions from wells drilled in 2015, increases in the Uinta Basin due to new Lower Mesaverde well completions and increases in the Williston Basin due to continued development drilling and higher gas capture rates in 2015. Gas volume increases in Pinedale and the Uinta Basin were also due to operating in ethane rejection during the majority of 2015 compared to operating in ethane recovery in 2014. These production increases were mostly offset by production decreases resulting from the divestitures of non-core properties in the Other Southern area in the second and fourth quarters of 2014 and a production decrease in Haynesville/Cotton Valley due to natural decline and the continued suspension of QEP's operated drilling program.

NGL sales. NGL sales were $80.0 million for the year ended December 31, 2015, a decrease of $143.3 million, or 64%, compared to 2014. This decrease was primarily a result of a 48% decrease in average price per barrel and a 31% decrease in production volumes. Pinedale and Uinta Basin NGL volumes decreased primarily due to operating in ethane rejection during the majority of 2015, compared to operating in ethane recovery in 2014. Additionally, Other Southern NGL volumes decreased due to the divestiture of non-core properties in the second and fourth quarters of 2014. These decreases were partially offset by increases in NGL volumes in the Williston and Permian basins as a result of increased development drilling and well completions, higher gas capture rates in 2015 in the Williston Basin and a full year of production from the Permian Basin in 2015 compared to 10 months of production in 2014. NGL price decreases were primarily driven by a significant decrease in the price of the NGL components, particularly the heavier components, which weakened in conjunction with the decline in oil prices.

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	
	2016	2015	2014	**2016 vs 2015**	2015 vs 2014
	(in millions)				
Purchased oil and gas sales	**$ 101.2**	$ 620.8	$ 913.9	**$ (519.6)**	$ (293.1)
Purchased oil and gas expense	**(105.5)**	(626.8)	(910.1)	**521.3**	283.3
Realized gains (losses) on gas storage derivative contracts	**2.9**	3.8	(2.5)	**(0.9)**	6.3
Resale margin	**$ (1.4)**	$ (2.2)	$ 1.3	**$ 0.8**	$ (3.5)

As a result of the termination of QEP Marketing agreements effective January 1, 2016, 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, than it had in prior periods. For additional details, see Note 1 – Summary of Significant Accounting Policies, in Part II, Item 8 of this Annual Report on Form 10-K.

Operating Expenses

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

	Year Ended December 31,			Change	
	2016	2015	2014	**2016 vs 2015**	2015 vs 2014
	(per Boe)				
Lease operating expense	**$ 4.03**	$ 4.38	$ 4.46	**$ (0.35)**	$ (0.08)
Oil, gas and NGL transportation and other handling costs	**5.18**	5.35	5.16	**(0.17)**	0.19
Production and property taxes	**1.70**	2.16	3.82	**(0.46)**	(1.66)
Total production costs	**$ 10.91**	$ 11.89	$ 13.44	**$ (0.98)**	$ (1.55)

December 31, 2016 compared to December 31, 2015

Lease operating expense (LOE). 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.

Oil, gas and NGL transportation and other handling costs. QEP's oil, gas and NGL transportation and other handling 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. QEP is disputing these charges and has filed a legal claim against the operator. 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. In most states in which QEP operates, QEP pays production taxes based on a percentage of field-level revenue, except in Louisiana, where severance taxes are volume based. Production and property taxes decreased $22.8 million, or $0.46 per Boe, during 2016, 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). 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 $55.6 million of impairment charges 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 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. 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 an impairment of goodwill. Of the $39.3 million impairment of 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 (G&A) expense. During 2016, G&A expense increased $17.3 million, or 10%, 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 Cash Incentive Plan (CIP). These increases were partially offset by a decrease in labor, benefits and employee expenses, which was primarily a result of a pension curtailment expense of $11.2 million recognized in the second quarter of 2015 (see Note 12 – Employee Benefits, in Item 8 of Part II of this Annual Report on Form 10-K), a $6.9 million decrease in professional and outside services expenses and a $6.6 million decrease in severance payments and restructuring costs (see Note 8 – Restructuring Costs, in Item 8 of Part II of this Annual Report on Form 10-K).

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.

December 31, 2015 compared to December 31, 2014

Lease operating expense. QEP's LOE decreased $1.3 million, or $0.08 per Boe, during the year ended December 31, 2015 compared to 2014. The decrease was driven by a decrease in the Other Southern area as a result of the property sales in the second and fourth quarters of 2014, partially offset by an increase in the Permian Basin due to additional development of oil properties that typically have higher operating costs, and an increase in the Williston Basin, primarily due to increased production.

Oil, gas and NGL transportation and other handling costs. QEP's oil, gas and NGL transportation and other handling costs increased $13.7 million, or $0.19 per Boe, during the year ended December 31, 2015 compared to 2014. The increase in expense was primarily attributable to additional expenses incurred in Haynesville/Cotton Valley as a result of recognizing approximately $9.8 million of fees for unutilized gathering and transportation capacity that was charged to QEP by the operator of wells in which QEP has a working interest. QEP is disputing these charges and has filed a legal claim against the operator. Additionally, there was an increase in expenses in Pinedale due to deficiency payments for NGL transportation commitments as a result of lower ethane volumes in 2015 and in the Permian Basin due to an increase in production volumes as a result of a full year of production in 2015 compared to only ten months of production in 2014. These increases were partially offset by a decrease in the Other Southern area due to divestitures of non-core properties in the second and fourth quarters of 2014.

Production and property taxes. Production and property taxes decreased $87.6 million, or $1.66 per Boe, during the year ended December 31, 2015 compared to 2014, primarily a result of decreased oil, gas and NGL revenues due to lower field-level prices and decreased NGL production volumes.

Depreciation, depletion and amortization. DD&A expense decreased $113.6 million during the year ended December 31, 2015 compared to 2014. The decrease in DD&A expense was due to decreases in Haynesville/Cotton Valley and the Other Southern area, partially offset by increases in the Williston Basin and Pinedale. The decrease in Haynesville/Cotton Valley was a result of declining production and a rate decrease due to an impairment at year-end 2014, while the decrease in the Other Southern area was a result of the second and fourth quarter of 2014 property sales. The increase in the Williston Basin's DD&A expense primarily relates to increased production and the increase in Pinedale's DD&A expense primarily relates to a rate increase due to a decrease in reserves at year-end 2014.

Impairment expense. During the year ended December 31, 2015, QEP recorded impairment charges of $55.6 million, compared to impairment charges of $1,143.2 million recorded during 2014. 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 an 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. Of the $1,143.2 million of impairment charges recorded during 2014, $1,041.4 million was related to impairment of proved properties due to lower future oil and gas prices and $101.8 million was related to expiring leaseholds on unproved properties due to lower future prices, lease expirations and changes in drilling plans. Of the $1,041.4 million impairment on proved properties, $532.1 million related to Haynesville/Cotton Valley properties, $467.7 million related to Permian Basin properties, $18.7 million related to Other Southern properties, $13.5 million related to Other Northern properties, $5.8 million related to Williston Basin properties and $3.6 million related to Uinta Basin properties.

Exploration expense. Exploration expense decreased $7.2 million during the year ended December 31, 2015 compared to 2014. The decrease primarily related to lower exploration-related labor.

General and administrative expense. During 2015, G&A expense decreased $23.3 million, or 11%, compared to 2014. The decrease in G&A expense in 2015 compared to 2014 was primarily due to the following: a $19.6 million decrease in professional and outside services and compensation expense mainly related to the 2014 Enterprise Resource Planning system implementation and a $24.5 million decrease in labor, benefits and employee expenses. These decreases were partially offset by an $11.2 million pension curtailment expense recognized in the second quarter of 2015 related to the changed in the Company's pension plan (see Note 12 – Employee Benefits, in Item 8 of Part II of this Annual Report on Form 10-K) and a $6.1 million increase in restructuring costs and severance payments primarily related to workforce reduction efforts in the first quarter of 2015 and the Tulsa office closure in the third quarter of 2015 (see Note 8 – Restructuring Costs, in Item 8 of Part II of this Annual Report on Form 10-K) and a $4.5 million increase in share-based compensation expense.

Net gain (loss) from asset sales. During the year ended December 31, 2015, QEP recognized a gain on sale of assets of $4.6 million, compared to a loss on sale of $148.6 million during the year ended December 31, 2014. The gain on sale of assets recognized in 2015 was primarily due to a $21.0 million gain related to the divestiture of non-core properties in 2015, partially offset by a $16.4 million loss recognized for post-closing adjustments related to 2014 divestitures. The loss on sale of assets recognized in 2014 was primarily due to the divestiture of the majority of QEP's Other Southern properties in 2014.

Non-Operating Expenses

December 31, 2016 compared to December 31, 2015

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, 2016, losses on commodity derivative instruments were $233.0 million, of which $367.0 million was unrealized losses, partially offset by $134.0 million of realized gains. During 2015, gains on commodity derivative instruments were $277.2 million, of which $460.9 million was realized gains, partially offset by $183.7 million in unrealized losses.

Interest and other income. Interest and other income increased $22.6 million during the year ended December 31, 2016 compared to 2015. The increase in interest and other income 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 (see Note 2 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K for additional details).

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.

December 31, 2015 compared to December 31, 2014

Realized and unrealized gains (losses) on derivative contracts. During the year ended December 31, 2015, gains on commodity derivative instruments were $277.2 million, of which $460.9 million were realized gains, partially offset by $183.7 million of unrealized losses. During 2014, gains on commodity derivative instruments were $368.9 million, of which $372.4 million was unrealized gains, partially offset by $3.5 million in realized losses. Additionally, during 2014, losses from interest rate swaps, which were terminated in December 2014, were $5.6 million, of which $7.6 million were realized losses, partially offset by $2.0 million of unrealized gains.

Interest expense. Interest expense decreased $23.5 million, or 14%, during the year ended December 31, 2015 compared to 2014. The decrease was attributable to average debt levels during the year ended December 31, 2015, that were $389.4 million, or 15%, lower than average debt levels during the year ended December 31, 2014. The decrease in average debt levels was primarily related to repaying all outstanding borrowings under the revolving credit facility and repaying the $600.0 million term loan from the proceeds of the Midstream Sale in December 2014.

Income tax (provision) benefit. Income tax benefit decreased $138.9 million during the year ended December 31, 2015 compared to 2014. The decrease in income tax benefit was the result of decreased net loss before income taxes, partially offset by a higher combined effective federal and state income tax rate of 38.5% during the year ended December 31, 2015, compared to 36.2% for the year ended December 31, 2014. The increase in the rate was due to the change in state tax rate as a result of an unrecognized tax benefit (see Note 13 – Income Taxes, in Item 8 of Part II of this Annual Report on Form 10-K).

LIQUIDITY AND CAPITAL RESOURCES

QEP strives to maintain a strong 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 capital expenditures with cash flow from its operating activities, cash on hand and, if needed, 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.

To provide additional liquidity, QEP also periodically accesses debt and equity markets and sells non-core properties. In 2016, QEP issued 60.95 million shares of common stock through two public offerings and received net 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 proceeds of approximately $29.0 million, $31.7 million and $783.8 million related to the sale of non-core properties during the years ended December 31, 2016, 2015 and 2014, respectively.

The Company estimates, that with its cash balance as of December 31, 2016, it could incur additional indebtedness of approximately $1.0 billion 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

QEP’s revolving credit facility, which matures in December 2019, provides for loan commitments of $1.8 billion from a group of financial institutions. The credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions. The credit agreement contains financial covenants (that are defined in the credit agreement) that limit the amount of debt the Company can incur and may limit the amount available to be drawn under the credit facility including: (i) a net funded debt to capitalization ratio that may not exceed 60%, (ii) a leverage ratio under which net funded debt may not exceed 4.25 times consolidated EBITDA (as defined in the credit agreement) for the fiscal quarters ending on and prior to December 31, 2017, and 3.75 times thereafter and (iii) a present value coverage ratio under which the present value of the Company’s proved reserves must exceed net funded debt by 1.25 times at any time prior to January 1, 2018, and 1.50 times at any time on or after January 1, 2018.

As of December 31, 2016 and 2015, QEP had no borrowings outstanding, had $2.8 million and $3.4 million, respectively, in letters of credit outstanding under the credit facility, and was in compliance with the covenants under the credit agreement. During the year ended December 31, 2014, QEP's weighted-average interest rate on borrowings from its credit facility was 2.23%. At February 17, 2017, QEP had no borrowings outstanding, had $2.8 million of letters of credit issued under the credit facility and was in compliance with the covenants under the credit agreement.

Senior Notes

The Company's senior notes outstanding as of December 31, 2016, totaled $2,045.0 million principal amount and are comprised of five issuances as follows:

- $134.0 million 6.80% Senior Notes due April 2018;
- $136.0 million 6.80% Senior Notes due March 2020;
- $625.0 million 6.875% Senior Notes due March 2021;
- $500.0 million 5.375% Senior Notes due October 2022; and
- $650.0 million 5.25% Senior Notes due May 2023.

During the year ended December 31, 2016, the Company paid $176.8 million for the repayment of the 6.05% Senior Notes, which were due on September 1, 2016.

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	
	2016	2015	2014	**2016 vs 2015**	2015 vs 2014
			(in millions)		
Net income (loss)	**$ (1,245.0)**	$ (149.4)	$ 784.4	**$ (1,095.6)**	$ (933.8)
Net income attributable to noncontrolling interest	**—**	—	21.6	**—**	(21.6)
Non-cash adjustments to net income	**1,794.1**	1,193.4	123.7	**600.7**	1,069.7
Changes in operating assets and liabilities	**114.6**	(562.7)	612.8	**677.3**	(1,175.5)
Net cash provided by operating activities	**$ 663.7**	$ 481.3	$ 1,542.5	**$ 182.4**	$ (1,061.2)

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 the 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 cash from operating assets and liabilities primarily included a decrease in accounts receivable of $96.5 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 $51.5 million, primarily related to timing of payments and receipts.

Net cash provided by operating activities during the year ended December 31, 2015, decreased $1,061.2 million compared to 2014, which included a $933.8 million decrease in net income, a $1,069.7 million increase in non-cash adjustments to net income and a $1,175.5 million decrease in cash from operating assets and liabilities. During the year ended December 31, 2015, non-cash adjustments to net income primarily included DD&A expense of $881.1 million, unrealized losses on derivative contracts of $183.7 million and $55.6 million of impairment expense. The decrease in cash from operating assets and liabilities primarily included a decrease in income taxes payable of $619.4 million, primarily related to income taxes paid on the gain on the Midstream Sale, which were paid in 2015, a decrease in accounts payable and accrued expenses of $71.3 million, partially offset by a decrease in accounts receivable of $165.5 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, 2016, 2015 and 2014, are presented in the table below:

	Year Ended December 31,			Change	
	2016	2015	2014	**2016 vs 2015**	2015 vs 2014
Property acquisitions	**$ 645.2**	$ 98.3	$ 960.5	**$ 546.9**	$ (862.2)
Property, plant and equipment capital expenditures	**530.1**	1,011.9	1,723.6	**(481.8)**	(711.7)
Continuing operations accrued capital expenditures	**1,175.3**	1,110.2	2,684.1	**65.1**	(1,573.9)
Discontinued operations accrued capital expenditures	**—**	—	50.7	**—**	(50.7)
Total accrued capital expenditures	**1,175.3**	1,110.2	2,734.8	**65.1**	(1,624.6)
Change in accruals and other non-cash adjustments	**32.8**	129.2	(8.4)	**(96.4)**	137.6
Total cash capital expenditures	**$ 1,208.1**	$ 1,239.4	$ 2,726.4	**$ (31.3)**	$ (1,487.0)

During the year ended December 31, 2016, on an accrual basis, the Company invested $530.1 million on property, plant and equipment capital expenditures, excluding property acquisitions, for continuing operations, 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.

During the year ended December 31, 2015, on an accrual basis, the Company invested $1,011.9 million on property, plant and equipment expenditures, excluding property acquisitions, for continuing operations, a decrease of $711.7 million compared to 2014. 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 proceeds from non-core asset divestitures, primarily in the Other Southern and Other Northern areas. In 2014, QEP's capital expenditures were $864.3 million in the Williston Basin, $356.9

million in the Permian Basin, $275.9 million in Pinedale, $78.4 million in the Uinta Basin, $50.3 million in Haynesville/Cotton Valley, $42.9 million in the Other Northern area and $41.3 million in the Other Southern area. In addition, during the year ended December 31, 2014, QEP had cash inflows of $3.3 billion from the Midstream Sale and other sales of non-core oil and gas properties, which was partially offset by $960.5 million of property acquisitions, primarily relating to the 2014 Permian Basin Acquisition.

The mid-point of our forecasted capital expenditures (excluding property acquisitions) for 2017 is $975.0 million. QEP intends to fund capital expenditures with cash flow from operating activities and cash on hand. The aggregate levels of capital expenditures for 2017 and the allocation of those expenditures are dependent on a variety of factors, including drilling results, oil, gas and NGL prices, industry conditions, the extent to which properties or working interests are acquired, the availability of capital resources to fund the expenditures and changes in management’s business assessments as to where QEP’s capital can be most profitably deployed. 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, 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).

During the year ended December 31, 2015, net cash used in financing activities was $47.7 million compared to net cash used in financing activities of $990.6 million during the year ended December 31, 2014. During the year ended December 31, 2015, the Company had a decrease in checks outstanding in excess of cash balances of $24.9 million, made dividend payments of $14.1 million and paid long-term debt issuance costs of $2.6 million. As of December 31, 2015, long-term debt consisted of $2,221.8 million in senior notes (excluding $30.3 million of net original issue discount and unamortized debt issuance costs). During the year ended December 31, 2014, the Company had borrowings from the revolving credit facility of $5,455.0 million and borrowings under the term loan of $300.0 million, which were used to fund the 2014 Permian Basin Acquisition and for operating activities throughout the year. The Company made repayments on its revolving credit facility of $5,935.0 million and repayments on its term loan of $600.0 million, which were primarily funded from the Midstream Sale and other non-core asset divestitures. There was a decrease in checks outstanding in excess of cash balances of $54.4 million and $99.7 million of cash was used to repurchase common stock, which was retired under the Company's share repurchase plan.

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, 2016, 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, 2016:

	Payments Due by Year [1]						
	Total	2017	2018	2019	2020	2021	After 2021
	(in millions)						
Long-term debt	$ 2,045.0	$ —	$ 134.0	$ —	$ 136.0	$ 625.0	$ 1,150.0
Interest on fixed-rate, long-term debt[2]	590.4	122.3	115.5	113.2	105.5	68.2	65.7
Drilling contracts	10.7	10.7	—	—	—	—	—
Gathering, processing, firm transportation, storage and other	683.0	120.0	111.9	104.5	87.8	51.0	207.8
Asset retirement obligations[3]	231.6	5.8	8.3	7.3	9.7	6.5	194.0
Operating leases	48.1	8.7	7.2	7.1	6.9	7.0	11.2
Total	$ 3,608.8	$ 267.5	$ 376.9	$ 232.1	$ 345.9	$ 757.7	$ 1,628.7

(1) This table excludes the Company's benefit plan liabilities as future payment dates are unknown. See Note 12 – 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. See Note 5 – 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 the years ended December 31, 2014 and 2015, commodity prices decreased, while during the year ended December 31, 2016, commodity prices increased. 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. See Note 15 – Supplemental Oil and Gas Information (unaudited), in Item 8 of Part II of this Annual Report on Form 10-K.

Successful Efforts Accounting for Oil and Gas Operations

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

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, 2016, 2015 and 2014, QEP recorded impairment expense of $1,172.7 million, $39.3 million and $1,041.4 million, respectively, related to some of its higher cost, proved properties in both of its Northern and Southern regions. The 2016, 2015 and 2014 impairment charges resulted from 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, 2016, 2015 and 2014, QEP recorded impairment charges of $17.9 million, $2.0 million and $101.8 million respectively, related to its unproved properties.

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, 2016, 2015 and 2014, was $231.6 million, $206.8 million and $195.1 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 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 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, 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. See Note 10 – 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 matters, 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. See Note 10 – 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. See Note 7 – 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 Statement 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. See Note 12 – 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. 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. See Note 11 – 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. See Note 13 – 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. See 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, 2016, QEP held commodity price derivative contracts totaling 25.9 million barrels of oil and 263.3 million MMBtu of gas. As of December 31, 2015, the QEP derivative contracts covered 9.2 million barrels of oil and 225.6 million MMBtu of gas.

The following table presents QEP's volumes and average prices for its derivative positions as of February 17, 2017. See Note 7 – Derivative Contracts, in Item 8 of Part II of this Annual Report on Form 10-K for open derivative positions as of December 31, 2016.

Production Commodity Derivative Swap Positions

Year	Index	Total Volumes		Average Swap Price per Unit
		(in millions)		
Oil sales		(bbls)		($/bbl)
2017	NYMEX WTI	12.4	$	51.39
2018	NYMEX WTI	8.4	$	53.71
Gas sales		(MMBtu)		($/MMBtu)
2017	NYMEX HH	79.6	$	2.86
2017	IFNPCR	27.5	$	2.51
2018	NYMEX HH	76.7	$	2.98

Production Commodity Derivative Gas Collars

Year	Index	Total Volumes		Average Price Floor		Average Price Ceiling
		(in millions)				
		(MMBtu)		($/MMBtu)		($/MMBtu)
2017	NYMEX HH	9.2	$	2.50	$	3.50

Production Commodity Derivative Basis Swaps

Year	Index Less Differential	Index	Total Volumes		Weighted-Average Differential
			(in millions)		
Oil sales			(bbls)		($/bbl)
2017	NYMEX WTI	Argus WTI Midland	3.5	$	(0.64)
2018	NYMEX WTI	Argus WTI Midland	2.6	$	(0.96)
Gas sales			(MMBtu)		($/MMBtu)
2017	NYMEX HH	IFNPCR	42.8	$	(0.18)
2018	NYMEX HH	IFNPCR	7.3	$	(0.16)

Gas Storage Commodity Derivative Positions

Year	Type of Contract	Index	Total Volumes		Average Swap Price per Unit
			(in millions)		
Gas sales			(MMBtu)		($/MMBtu)
2017	SWAP	IFNPCR	2.7	$	2.77

Changes in the fair value of derivative contracts from December 31, 2015 to December 31, 2016, are presented below:

		Commodity derivative contracts
		(in millions)
Net fair value of oil and gas derivative contracts outstanding at December 31, 2015	$	165.2
Contracts settled		**(134.1)**
Change in oil and gas prices on futures markets		**(74.5)**
Contracts added		**(158.4)**
Net fair value of oil and gas derivative contracts outstanding at December 31, 2016	**$**	**(201.8)**

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, 2016
		(in millions)
Net fair value - asset (liability)	**$**	**(201.8)**
Fair value if market prices of oil, gas and basis differentials decline by 10%		**(181.6)**
Fair value if market prices of oil, gas and basis differentials increase by 10%		**(221.9)**

Utilizing the actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these instruments by $20.1 million, while a 10% decrease in underlying commodity prices would increase the fair value of these instruments by $20.2 million as of December 31, 2016. 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, see Note 7 – Derivative Contracts, in Item 8 of Part II of this Annual Report on Form 10-K.

Interest Rate Risk Management

The Company's ability to borrow and the rates offered by lenders can be adversely affected by illiquid credit markets and the Company's credit rating as described in the Risk Factors, in Item 1A of Part I of this Annual Report on Form 10-K. The Company's revolving credit facility has a floating interest rate, which exposes QEP to interest rate risk if QEP has borrowings outstanding. At December 31, 2016 and December 31, 2015, the Company did not have any borrowings outstanding under its revolving credit facility.

The remaining $2,045.0 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, see Note 9 – Debt, in Item 8 of Part II of this Annual Report on Form 10-K.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

All 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 Board of Directors and Shareholders of QEP Resources, Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, comprehensive income (loss), equity and cash flows present fairly, in all material respects, the financial position QEP Resources, Inc. and its subsidiaries at December 31, 2016 and December 31, 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 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, 2016, based on criteria established in *Internal Control - Integrated Framework(2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these 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 under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. 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.

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

Houston, Texas
February 22, 2017

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2016	2015	2014
REVENUES	(in millions, except per share amounts)		
Oil sales	**$ 769.1**	$ 834.2	$ 1,368.5
Gas sales	**417.1**	468.5	776.4
NGL sales	**83.5**	80.0	223.3
Other revenues	**6.2**	15.1	11.1
Purchased oil and gas sales	**101.2**	620.8	913.9
Total Revenues	**1,377.1**	2,018.6	3,293.2
OPERATING EXPENSES			
Purchased oil and gas expense	**105.5**	626.8	910.1
Lease operating expense	**224.7**	238.8	240.1
Oil, gas and NGL transportation and other handling costs	**289.2**	291.3	277.6
Gathering and other expense	**5.0**	5.8	6.7
General and administrative	**198.4**	181.1	204.4
Production and property taxes	**94.8**	117.6	205.2
Depreciation, depletion and amortization	**871.1**	881.1	994.7
Exploration expenses	**1.7**	2.7	9.9
Impairment	**1,194.3**	55.6	1,143.2
Total Operating Expenses	**2,984.7**	2,400.8	3,991.9
Net gain (loss) from asset sales	**5.0**	4.6	(148.6)
OPERATING INCOME (LOSS)	**(1,602.6)**	(377.6)	(847.3)
Realized and unrealized gains (losses) on derivative contracts (Note 7)	**(233.0)**	277.2	363.3
Interest and other income	**25.6**	3.0	12.8
Income from unconsolidated affiliates	**—**	—	0.3
Loss from early extinguishment of debt	**—**	—	(2.0)
Interest expense	**(143.2)**	(145.6)	(169.1)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	**(1,953.2)**	(243.0)	(642.0)
Income tax (provision) benefit	**708.2**	93.6	232.5
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	**(1,245.0)**	(149.4)	(409.5)
Net income from discontinued operations, net of income tax	**—**	—	1,193.9
NET INCOME (LOSS)	**$ (1,245.0)**	$ (149.4)	$ 784.4
Earnings (loss) per common share			
Basic from continuing operations	**$ (5.62)**	$ (0.85)	$ (2.28)
Basic from discontinued operations	**—**	—	6.64
Basic total	**$ (5.62)**	$ (0.85)	$ 4.36
Diluted from continuing operations	**$ (5.62)**	$ (0.85)	$ (2.28)
Diluted from discontinued operations	**—**	—	6.64
Diluted total	**$ (5.62)**	$ (0.85)	$ 4.36
Weighted-average common shares outstanding			
Used in basic calculation	**221.7**	176.6	179.8
Used in diluted calculation	**221.7**	176.6	179.8
Dividends per common share	**$ —**	$ 0.08	$ 0.08

See Notes accompanying the Consolidated Financial Statements.

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

	Year Ended December 31,		
	2016	2015	2014
	(in millions)		
Net income (loss)	**$ (1,245.0)**	$ (149.4)	$ 784.4
Other comprehensive income, net of tax:			
Pension and other postretirement plans adjustments:			
Current period prior service cost[1]	**—**	(0.6)	—
Current period net actuarial (gain) loss[2]	**(5.6)**	(0.5)	(13.6)
Amortization of prior service cost[3]	**0.8**	8.2	9.7
Amortization of net actuarial (gain) loss[4]	**0.5**	0.3	0.5
Net curtailment and settlement cost incurred[5]	**—**	4.5	5.6
Other comprehensive income	**(4.3)**	11.9	2.2
Comprehensive income (loss)	**$ (1,249.3)**	$ (137.5)	$ 786.6

(1) Presented net of income tax benefit of $0.3 million for the year ended December 31, 2015.
(2) Presented net of income tax benefit of $3.3 million, $0.3 million and $8.5 million for the years ended December 31, 2016, 2015 and 2014, respectively.
(3) Presented net of income tax expense of $0.5 million, $4.9 million, and $6.0 million during the years ended December 31, 2016, 2015, and 2014, respectively.
(4) Presented net of income tax expense of $0.3 million, $0.2 million, and $0.3 million during the years ended December 31, 2016, 2015, and 2014, respectively.
(5) Presented net of income tax expense of $2.6 million and $3.5 million for the years ended December 31, 2015 and 2014, respectively.

See Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2016	December 31, 2015
ASSETS	(in millions)	
Current Assets		
Cash and cash equivalents	**$ 443.8**	$ 376.1
Accounts receivable, net	**155.7**	278.2
Income tax receivable	**18.6**	87.3
Fair value of derivative contracts	**—**	146.8
Oil, gas and NGL inventories, at lower of average cost or market	**10.4**	13.3
Prepaid expenses and other	**11.6**	30.1
Total Current Assets	**640.1**	931.8
Property, Plant and Equipment (successful efforts method for oil and gas properties)		
Proved properties	**14,232.5**	13,314.9
Unproved properties	**871.5**	691.0
Marketing and other	**301.8**	297.9
Materials and supplies	**32.7**	38.5
Total Property, Plant and Equipment	**15,438.5**	14,342.3
Less Accumulated Depreciation, Depletion and Amortization		
Exploration and production	**8,797.7**	6,870.2
Marketing and other	**101.8**	87.5
Total Accumulated Depreciation, Depletion and Amortization	**8,899.5**	6,957.7
Net Property, Plant and Equipment	**6,539.0**	7,384.6
Fair value of derivative contracts	**—**	23.2
Other noncurrent assets	**66.3**	58.6
TOTAL ASSETS	**$ 7,245.4**	$ 8,398.2
LIABILITIES AND EQUITY		
Current Liabilities		
Checks outstanding in excess of cash balances	**$ 12.3**	$ 29.8
Accounts payable and accrued expenses	**269.7**	351.7
Production and property taxes	**30.1**	46.1
Interest payable	**32.9**	36.4
Fair value of derivative contracts	**169.8**	0.8
Current portion of long-term debt	**—**	176.8
Total Current Liabilities	**514.8**	641.6
Long-term debt	**2,020.9**	2,014.7
Deferred income taxes	**825.9**	1,479.8
Asset retirement obligations	**225.8**	204.9
Fair value of derivative contracts	**32.0**	4.0
Other long-term liabilities	**123.3**	105.3
Commitments and Contingencies (Note 10)		
EQUITY		
Common stock – par value $0.01 per share; 500.0 million shares authorized; 240.7 million and 177.3 million shares issued, respectively	**2.4**	1.8
Treasury stock – 1.1 million and 0.5 million shares, respectively	**(22.9)**	(14.6)
Additional paid-in capital	**1,366.6**	554.8
Retained earnings	**2,173.3**	3,418.3
Accumulated other comprehensive income (loss)	**(16.7)**	(12.4)
Total Common Shareholders' Equity	**3,502.7**	3,947.9
TOTAL LIABILITIES AND EQUITY	**$ 7,245.4**	$ 8,398.2

See 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)	Non-controlling Interest	Total
	Shares	Amount	Shares	Amount					
	(in millions)								
Balance at December 31, 2013	179.7	$ 1.8	(0.4)	$ (14.9)	$ 498.4	$ 2,917.8	$ (26.5)	$ 500.2	$ 3,876.8
Net income (loss)	—	—	—	—	—	784.4	—	—	784.4
Dividends paid	—	—	—	—	—	(14.6)	—	—	(14.6)
Share-based compensation	1.2	—	(0.4)	(10.5)	36.9	—	—	0.2	26.6
Distribution of noncontrolling interest	—	—	—	—	—	—	—	(31.9)	(31.9)
Common stock repurchased and retired	(4.7)	—	—	—	—	(99.7)	—	—	(99.7)
Noncontrolling interest decrease from sale of substantially all of QEP's midstream business	—	—	—	—	—	—	—	(468.5)	(468.5)
Change in pension and postretirement liability, net of tax	—	—	—	—	—	—	2.2	—	2.2
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**

See Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2016	2015	2014
OPERATING ACTIVITIES	(in millions)		
Net income (loss)	**$ (1,245.0)**	$ (149.4)	$ 784.4
Net income attributable to noncontrolling interest	**—**	—	21.6
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**871.1**	881.1	1,040.6
Deferred income taxes	**(651.3)**	25.3	(84.1)
Impairment	**1,194.3**	55.6	1,143.2
Bargain purchase gain from acquisitions	**(22.6)**	—	—
Share-based compensation	**35.6**	34.7	27.9
Pension curtailment loss	**—**	11.2	—
Amortization of debt issuance costs and discounts	**6.4**	6.2	6.7
Net (gain) loss from asset sales	**(5.0)**	(4.6)	(1,644.8)
Income from unconsolidated affiliates	**—**	—	(5.2)
Distributions from unconsolidated affiliates and other	**—**	—	9.4
Non-cash loss on early extinguishment of debt	**—**	—	4.4
Unrealized (gains) losses on marketable securities	**(1.4)**	0.2	—
Unrealized (gains) losses on derivative contracts	**367.0**	183.7	(374.4)
Changes in operating assets and liabilities			
Accounts receivable	**96.5**	165.5	(160.5)
Inventories	**8.7**	15.5	(20.2)
Prepaid expenses	**18.5**	16.7	(7.3)
Accounts payable and accrued expenses	**(51.5)**	(71.3)	320.1
Federal income taxes	**68.7**	(619.4)	494.1
Other	**(26.3)**	(69.7)	(13.4)
Net Cash Provided by (Used in) Operating Activities	**663.7**	481.3	1,542.5
INVESTING ACTIVITIES			
Property acquisitions	**(639.0)**	(98.3)	(960.5)
Property, plant and equipment, including dry hole exploratory well expense	**(569.1)**	(1,141.1)	(1,765.9)
Proceeds from disposition of assets	**29.0**	21.8	3,296.6
Acquisition deposit held in escrow	**—**	—	50.0
Other investing activities	**—**	—	(42.0)
Net Cash Provided by (Used in) Investing Activities	**(1,179.1)**	(1,217.6)	578.2
FINANCING ACTIVITIES			
Checks outstanding in excess of cash balances	**(17.5)**	(24.9)	(54.4)
Long-term debt issued	**—**	—	300.0
Long-term debt issuance costs paid	**—**	(2.6)	(9.3)
Long-term debt repaid	**(176.8)**	—	(600.0)
Proceeds from credit facility	**—**	—	5,455.0
Repayments of credit facility	**—**	—	(5,935.0)
Common stock repurchased and retired	**—**	—	(99.7)
Treasury stock repurchases	**(4.1)**	(2.7)	(6.2)
Other capital contributions	**—**	(0.2)	6.0
Dividends paid	**—**	(14.1)	(14.6)
Proceeds from issuance of common stock, net	**781.4**	—	—
Excess tax (provision) benefit on share-based compensation	**0.1**	(3.2)	(0.5)
Distribution to noncontrolling interest	**—**	—	(31.9)
Net Cash Provided by (Used in) Financing Activities	**583.1**	(47.7)	(990.6)
Change in cash and cash equivalents	**67.7**	(784.0)	1,130.1
Beginning cash and cash equivalents	**376.1**	1,160.1	30.0
Ending cash and cash equivalents	**$ 443.8**	$ 376.1	$ 1,160.1

See 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 focused in two regions of the United States: the Northern Region (primarily in North Dakota, Wyoming 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 and S-K. 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.

Changes 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) reporting segment, excluding the retained ownership of the Haynesville gathering system (Haynesville Gathering), were classified as discontinued operations on the Consolidated Statement of Operations and the Notes accompanying 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 is directly marketing its own oil, gas and NGL production. While QEP will continue 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 Midstream Sale and the termination of marketing agreements to show its financial results without segments.

Equity Offerings

In June 2016, QEP issued 23.0 million shares of common stock through a public offering and received net proceeds of approximately $412.9 million. In October 2016, QEP used the net proceeds from this offering to partially fund the 2016 Permian Basin Acquisition (see Note 2 – Acquisitions and Divestitures).

In March 2016, QEP issued 37.95 million shares of common stock through a public offering and received net proceeds of approximately $368.5 million. QEP used the net proceeds from this offering for general corporate purposes.

Reclassifications

Certain prior period balances on the Consolidated Balance Sheets have been reclassified to conform to the current year presentation. Such reclassifications had no effect on the Company's operating income, net income, earnings per share, cash flows 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. See Note 7 – Derivative Contracts for the Company’s open oil and gas commodity derivative contracts. QEP generally funds its operations and capital expenditures with cash flow from its operating activities, cash on hand and, if needed, borrowings under its revolving credit facility. The Company expects to be able to fund its operations, planned capital expenditures and working capital requirements during the next 12 months and the foreseeable future. However, continued low oil and gas prices could have an adverse effect on the Company’s financial position, results of operations, cash flows, credit ratings and quantities of oil and gas reserves that may be economically produced, which could impact the Company’s ability to comply with the financial covenants under its credit facility and limit further borrowings to fund capital expenditures. Additionally, if forward prices remain low or decline further, the Company could incur additional impairment of its oil and gas assets or other investments.

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.

Cash and Cash Equivalents and Restricted Cash

Cash equivalents consist principally of highly liquid investments in securities with maturities of three months or less made through commercial bank accounts that result in available funds the next business day.

As of December 31, 2016, QEP had unrestricted cash of $443.8 million and restricted cash of $21.6 million. As of December 31, 2015, QEP had unrestricted cash of $376.1 million and restricted cash of $18.1 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" and "Prepaid expenses and other" on the Consolidated Balance Sheet.

Supplemental cash flow information is shown in the table below:

	Year Ended December 31,		
	2016	2015	2014
Supplemental Disclosures	(in millions)		
Cash paid for interest, net of capitalized interest	**$ 139.1**	$ 139.4	$ 163.2
Cash paid (refund received) for income taxes, net	**$ (123.5)**	$ 487.8	$ 0.3
Non-cash investing activities			
Change in capital expenditure accrual balance	**$ (32.8)**	$ (129.2)	$ 8.4

Accounts Receivable

Accounts receivable consists mainly of receivables from oil and gas purchasers and joint interest owners on properties the Company operates. For receivables from joint interest owners, the Company has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Generally, the Company's oil and gas receivables are collected and bad debts are minimal. However, if commodity prices remain low for an extended period of time, the Company could incur increased levels of bad debt expense. Bad debt expense associated with accounts receivable for the years ended December 31, 2016, 2015 and 2014, was $1.8 million, $0.5 million, and $2.1 million, respectively, and is included in "General and administrative" expense on the Consolidated Statement 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 $4.8 million at December 31, 2016, and $3.9 million at December 31, 2015.

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 market. 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, 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 Other Northern properties 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 of proved properties, $20.2 million related to QEP's remaining Other Southern properties, $18.4 million related to Other Northern properties and $0.7 million related to Permian Basin properties.

During the year ended December 31, 2014, QEP recorded impairment charges of $1,143.2 million, of which $1,041.4 million was related to proved properties due to lower future oil and gas prices and $101.8 million was related to impairment of unproved properties due to lower future prices, lease expirations and changes in drilling plans. Of the $1,041.4 million impairment on proved properties, $532.1 million related to Haynesville/Cotton Valley properties, $467.7 million related to Permian Basin properties, $18.7 million related to QEP's remaining Other Southern properties, $13.5 million related Other Northern properties, $5.8 million related to Williston Basin properties and $3.6 million related to Uinta Basin properties.

Asset Retirement Obligations
QEP is obligated to fund the costs of disposing of long-lived assets upon their abandonment. The majority of QEP's asset retirement obligations (ARO) relate to the plugging of wells and the related abandonment of oil and gas 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. See Note 5 – 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. Goodwill is tested for impairment under a two-step quantitative test on an annual basis or when a triggering event occurs. Under the first step, the estimated fair value of the reporting unit is compared with its carrying value (including goodwill). QEP determines 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. If the fair value of the reporting unit exceeds its carrying value, step two does not need to be performed. If the estimated fair value of the reporting unit is less than its carrying value, an indication of goodwill impairment exists for the reporting unit and the Company performs step two of the impairment test (measurement). Under step two, an impairment loss is recognized for any excess of the carrying amount of the reporting unit's goodwill over the implied fair value of that goodwill. The implied fair value of goodwill is determined by allocating the fair value of the reporting unit in a manner similar to a purchase price allocation in acquisition accounting. The residual fair value after this allocation is the implied fair value of the reporting unit goodwill. Fair value of the reporting unit under the two-step assessment is determined using a discounted cash flow analysis.

During the year ended December 31, 2016, QEP recorded $3.7 million of goodwill, which related to an acquisition in the first quarter of 2016. During the performance of a goodwill impairment test performed during the first quarter of 2016, QEP failed the first step of the goodwill impairment test as described above, primarily due to lower future oil and gas prices. QEP performed the second step test described above, which resulted in a full write down of goodwill of $3.7 million.

During the year ended December 31, 2015, QEP recorded $14.3 million of goodwill related to an acquisition in December 2015. During the performance of QEP's annual goodwill impairment test at December 31, 2015, QEP failed the first step of the goodwill impairment test as described above, primarily due to lower future oil and gas prices. QEP performed the second step test described above, which resulted in a full write down of goodwill of $14.3 million as of December 31, 2015. During the year ended December 31, 2014, QEP recorded no goodwill impairments.

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 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. See Note 10 – 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 known as fixed-price swaps or 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 Statement of Operations in the month of settlement and are also marked-to-market monthly. See Note 7 – 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 48%, 30%, and 33% of QEP's revenues for the years ended December 31, 2016, 2015 and 2014, respectively. 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. During the year ended December 31, 2014, Valero Marketing & Supply Company accounted for 10% 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. As of December 31, 2016, the Company had a valuation allowance of $20.6 million against the state net operating loss deferred tax asset because the sale of properties in Oklahoma will preclude its utilization in the future. All federal income tax returns prior to 2016 have been examined by the Internal Revenue Service and are closed. Income tax returns for 2016 have not yet been filed. Most state tax returns for 2013 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" on the

Consolidated Statement of Operations, any interest expense related to uncertain tax positions in "Interest expense" on the Consolidated Statement 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, 2016 and 2015, QEP had $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 Sheet. 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. During the year ended December 31, 2014, no uncertain tax positions were recorded.

Treasury Stock

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

Share Repurchases and Retirements

In January 2014, QEP's Board of Directors authorized the repurchase of up to $500.0 million of the Company's outstanding shares of common stock. During the year ended December 31, 2015, no shares were repurchased under this program. During the year ended December 31, 2014, QEP repurchased 4,731,438 shares at a weighted-average price of $21.08 per share, including commission of $0.02 per share, for $99.7 million under this program. This program expired on December 31, 2015.

Earnings Per Share

Basic earnings per share (EPS) are computed by dividing net income 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 per share pursuant to the two-class method. The Company's unvested restricted stock 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 stock does 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 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 per common share. For the years ended December 31, 2016 and 2014, there were 0.1 million and 0.3 million shares, respectively, not included in diluted common shares outstanding as they were anti-dilutive due to QEP's net loss from continuing operations. For the year ended December 31, 2015, there were no anti-dilutive shares. A reconciliation of the components of basic and diluted shares used in the EPS calculation follows:

	December 31,		
	2016	2015	2014
	(in millions)		
Weighted-average basic common shares outstanding	**221.7**	176.6	179.8
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	**221.7**	176.6	179.8

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 an accelerated method in recognizing share-based compensation costs for stock options and restricted share awards with graded-vesting periods. 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. QEP uses the Black-Scholes-Merton mathematical model to estimate the fair value of stock options for accounting purposes. 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. Non-vested restricted share awards have voting and dividend rights; however, sale or transfer is restricted. 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. 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. The Company also awards performance share units under its Cash Incentive Plan (CIP), which 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, see Note 11 – 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 Statement 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. See Note 12 – Employee Benefits for additional information.

Comprehensive Income

Comprehensive income is the sum of net income as reported in the Consolidated Statements of Operations and changes in the components of other comprehensive income. Other comprehensive income includes certain items that are recorded directly to equity and classified as AOCI, which includes changes in the under-funded portion of the Company's defined benefit pension plans 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 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 31, 2017 and early adoption is permitted for periods beginning on or after December 31, 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 has not yet selected a transition method and is currently assessing the impact of the ASU on the Company's Consolidated Financial Statements.

In August 2014, the FASB issued ASU No. 2014-15, *Presentation of Financial Statements-Going Concern (Topic 205-40): Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern*. This guidance provides additional information to guide management's evaluation of whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity’s ability to continue as a going concern within one year after the date that the financial statements are issued. The amendment was effective for annual periods ending after December 15, 2016. The adoption of this new standard did not have a material impact on the Company's Consolidated Financial Statements.

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 disclosing key quantitative and qualitative information about leasing arrangements. The amendment will be effective for reporting periods beginning on or 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 will be effective prospectively for reporting periods beginning on or after December 15, 2016, and early adoption is permitted. The Company does not expect that the adoption of this new standard will have a material impact on the Company's Consolidated Financial Statements.

In March 2016, the FASB issued ASU No. 2016-08, *Revenue from contracts with customers (Topic 606): Principal versus agent considerations (reporting revenue gross versus net),* which clarifies the implementation guidance on principal versus agent considerations. The amendment will be effective prospectively for reporting periods beginning on or after December 31, 2017, and early adoption is permitted for periods beginning on or after December 31, 2016. 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. 2016-09, *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 on or after December 15, 2016, and early adoption was permitted. The adoption of this new standard will not have a material impact on the Company's Consolidated Financial Statements.

In April 2016, the FASB issued ASU No. 2016-10, *Revenue from contracts with customers (Topic 606): Identifying performance obligations and licensing,* which clarifies guidance related to identifying performance obligations and licensing implementation guidance contained in the new revenue recognition standard. This amendment will be effective prospectively for reporting periods beginning on or after December 15, 2017, and early adoption is permitted for periods beginning on or after December 31, 2016. The Company is currently assessing the impact of the ASU on the Company's Consolidated Financial Statements.

In May 2016, the FASB issued ASU No. 2016-11, *Revenue recognition (Topic 605) and Derivatives and hedging (Topic 815): Rescission of SEC guidance because of ASU 2014-09 and 2014-16,* which rescinds certain SEC staff observer comments that are codified in *Topic 605, Revenue Recognition.* This amendment will be effective prospectively for reporting periods beginning on or after December 15, 2017, and early adoption is permitted for periods beginning on or after December 31, 2016. The Company is currently assessing the impact of the ASU on the Company's Consolidated Financial Statements.

In May 2016, the FASB issued ASU No. 2016-12, *Revenue from contracts with customers (Topic 606): Narrow-scope improvements and practical expedients,* which intends to reduce the cost and complexity of applying the new revenue standard by narrowing the scope of improvements to the guidance on collectability, non-cash consideration, and completed contracts at transition. This amendment will be effective prospectively for reporting periods beginning on or after December 15, 2017, and early adoption is permitted for periods beginning on or after December 31, 2016. The Company is currently assessing the impact of the ASU 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 does not expect that the adoption of this new standard will have a material impact on the Company's Consolidated Financial Statements.

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

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

In December 2016, the FASB issued ASU No. 2016-19, *Technical Corrections and Improvements*, which intends to make corrections or improvements to the FASB Accounting Standards Codification which includes guidance and reference clarification, simplification and minor improvements. This amendment is effective immediately. The adoption of this standard did not have a material impact on the Company's Consolidated Financial Statements.

In December 2016, the FASB issued ASU No. 2016-20, *Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers,* which intends to make corrections or improvements to the FASB Accounting Standards Codification which includes guidance and reference clarification, simplification and minor improvements. This amendment will be effective prospectively for reporting periods beginning on or after December 15, 2017, and early adoption is permitted for periods beginning on or after December 31, 2016. The Company is currently assessing the impact of the ASU on the Company's Consolidated Financial Statements.

Note 2 – Acquisitions and Divestitures

2016 Permian Basin Acquisition

In October 2016, QEP acquired oil and gas properties in the Permian Basin for an aggregate purchase price of approximately $590.6 million, subject to customary purchase price adjustments (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 the June 2016 equity offering and cash on hand.

The 2016 Permian Basin Acquisition meets the definition of a business combination under ASC 805, *Business Combinations*, as it includes 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 $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, and 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 Statement of Operations. In conjunction with the 2016 Permian Basin Acquisition, the Company recorded an $18.2 million bargain purchase gain. The bargain purchase gain is reported on the Consolidated Statements of Operations within "Interest and other income (expense)". 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 Consolidated Balance Sheet as of December 31, 2016, includes the 2016 Permian Basin Acquisition. The following table presents a summary of the Company's purchase accounting entries (in millions):

Consideration:		
Total consideration	**$**	**590.6**
Amounts recognized for fair value of assets acquired and liabilities assumed:		
Proved properties	**$**	**406.2**
Unproved properties		**214.2**
Asset retirement obligations		**(11.6)**
Bargain purchase gain		**(18.2)**
Total fair value	**$**	**590.6**

The following unaudited, pro forma results of operations are provided for the years ended December 31, 2016 and 2015. These 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 years ended December 31, 2016 and 2015, 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 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 preliminary 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		2015	
	Actual	**Pro forma**	Actual	Pro forma
	(in millions, except per share amounts)			
Revenues	**$ 1,377.1**	**$ 1,392.5**	$ 2,018.6	$ 2,041.5
Net income (loss)	**$ (1,245.0)**	**$ (1,246.8)**	$ (149.4)	$ (152.5)

Earnings (loss) per common share								
Basic	**$**	**(5.62)**	**$**	**(5.62)**	$	(0.85)	$	(0.86)
Diluted	**$**	**(5.62)**	**$**	**(5.62)**	$	(0.85)	$	(0.86)

2014 Permian Basin Acquisition

In February 2014, QEP acquired oil and gas properties in the Permian Basin for an aggregate purchase price of $941.8 million (the Permian Basin Acquisition). The acquired properties consisted of approximately 26,500 net acres of producing and undeveloped oil and gas properties and approximately 270 vertical producing wells in the Permian Basin, which created a new core area of operation for QEP.

The 2014 Permian Basin Acquisition met the definition of a business combination under ASC 805, *Business Combinations*, as it included significant proved properties. QEP allocated the cost of the 2014 Permian Basin Acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Revenues of $186.0 million and a net loss of $13.2 million were generated from the acquired properties during the year ended December 31, 2016. Revenues of $149.9 million and a net loss of $2.8 million were generated from the acquired properties during the year ended December 31, 2015. Revenues of $159.5 million and a net loss of $438.3 million were generated from the acquired properties from February 25, 2014 to December 31, 2014, and are included in QEP's Consolidated Statements of Operations. The significant net loss in 2014 was primarily due to an impairment of proved properties of $467.7 million recognized in 2014 due to the decrease in the future oil prices.

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

Consideration:		
Total consideration	$	941.8
Amounts recognized for fair value of assets acquired and liabilities assumed:		
Proved properties	$	472.1
Unproved properties		480.6
Asset retirement obligations		(9.7)
Liabilities assumed		(1.2)
Total fair value	$	941.8

The following unaudited, pro forma results of operations are provided for the year ended December 31, 2014. Pro forma results are not provided for the years ended December 31, 2015 and 2016, because the 2014 Permian Basin Acquisition occurred during the first quarter of 2014, and therefore the 2014 Permian Basin Acquisition results are included in QEP's results for these periods. These 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 period 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, 2014, 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 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 have resulted from the 2014 Permian Basin Acquisition or any estimated costs that have been incurred by the Company to integrate the acquired properties.

	Year ended December 31,			
	2014			
	Actual		Pro Forma	
	(in millions, except per share amounts)			
Revenues	$	3,293.2	$	3,319.3
Net income (loss)	$	784.4	$	791.4
Earnings (loss) per common share				
Basic	$	4.36	$	4.40
Diluted	$	4.36	$	4.40

Other Acquisitions

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, subject to customary purchase price adjustments, 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 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. In conjunction with the acquisitions, the Company recorded $14.3 million of goodwill, which was subsequently impaired.

In addition to the 2014 Permian Basin Acquisition, QEP acquired various oil and gas properties in 2014, primarily in the Other Northern area and the Uinta Basin, for a total purchase price of $18.7 million, which included acquisitions of additional interests in QEP operated wells and additional undeveloped leasehold acreage.

Divestitures

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 $8.4 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 and recorded a pre-tax gain on sale of $21.0 million. For the year ended December 31, 2016, QEP recorded a pre-tax loss on sale of $0.9 million, due to post-closing purchase price adjustments from the sale of such properties.

During the year ended December 31, 2014, QEP sold its interest in certain non-core properties in the Other Southern area and Williston Basin for aggregate proceeds of $783.8 million and recorded a pre-tax loss on sale of $147.0 million. During the years ended December 31, 2016 and 2015, QEP recorded a pre-tax gain of sale of $0.6 million and a pre-tax loss on sale of $9.3 million, respectively, 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 – Discontinued Operations

In December 2014, the Company sold substantially all of its midstream business, including its 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).

The results of operations of QEP Field Services Company (QEP Field Services), excluding Haynesville Gathering (the Discontinued Operations of QEP Field Services), were classified as discontinued operations on the Consolidated Statements of Operations and Notes accompanying the Consolidated Financial Statements for the year ended December 31, 2014. QEP will have continuing cash outflows to the entities sold as a part of the Midstream Sale for gathering, processing and water handling costs in Pinedale, the Uinta Basin and a portion of its Williston Basin operations. The contracts related to these cash flows vary in length from month-to-month to over a year and will be reviewed periodically in the normal course of business. Historically, these transactions were eliminated in consolidation, as they represented transactions between two related entities but are now reflected as part of the continuing operations for QEP. For the years ended December 31, 2016, 2015 and 2014, cash outflows for these transactions included in continuing operations were $137.9 million, $131.8 million and $145.3 million, respectively.

In 2013, in connection with QEP's plan to separate its midstream business, the Board of Directors approved an employee retention plan to provide substantially all QEP Field Services' employees as of December 1, 2013, with a one-time lump-sum cash payment on the earlier of December 31, 2014, or whenever the separation of QEP Field Services occurred, conditioned on continued employment with QEP Field Services or a successor through the payment date unless the employee was terminated prior to such date. QEP recognized $10.4 million of costs under this retention plan during the year ended December 31, 2014, which is included within "Discontinued operations, net of income tax" on the Consolidated Statements of Operations.

Consolidated Statement of Operation

The Discontinued Operations of QEP Field Services is summarized below:

	Year Ended December 31, 2014
REVENUES	(in millions)
NGL sales	$ 109.3
Other revenues	140.9
Purchased oil and gas sales[1]	(47.1)
Total Revenues	203.1
OPERATING EXPENSES	
Purchased oil and gas expense[1]	(48.5)
Lease operating expense[1]	(5.5)
Oil, gas and NGL transport & other handling costs[1]	(55.4)
Gathering, processing, and other	85.9
General and administrative	42.1
Production and property taxes	7.3
Depreciation, depletion and amortization	45.9
Total Operating Expenses	71.8
Net gain (loss) from asset sales	1,793.4
OPERATING INCOME	1,924.7
Interest and other income	0.3
Income from unconsolidated affiliates	4.9
Loss on early extinguishment of debt	(2.4)
Interest expense	(3.8)
INCOME FROM DISCONTINUED OPERATIONS BEFORE INCOME TAXES[2]	1,923.7
Income tax (provision) benefit	(708.2)
NET INCOME FROM DISCONTINUED OPERATIONS	1,215.5
Net income attributable to noncontrolling interest	(21.6)
NET INCOME FROM DISCONTINUED OPERATIONS, NET OF INCOME TAX	$ 1,193.9

(1) Includes discontinued intercompany eliminations.

(2) Includes income from discontinued operations before income taxes attributable to QEP from QEP Midstream (of which QEP owned 57.8%) of $28.9 million for the year ended December 31, 2014.

Consolidated Statement of Cash Flows

The impact of the Discontinued Operations of QEP Field Services on the Consolidated Statements of Cash Flows for "Depreciation, depletion and amortization" contained in "Cash flows from operating activities" was $45.9 million for the year ended December 31, 2014. The impact on cash used for "Property, plant and equipment, including dry hole exploratory well expense" contained in "Cash flows from investing activities" was $55.2 million for the year ended December 31, 2014.

Note 4 – Capitalized Exploratory Well Costs

Net changes in capitalized exploratory well costs are presented in the table below. The balances at December 31, 2016, 2015 and 2014, represent the amount of capitalized exploratory well costs that are pending the determination of proved reserves.

	Capitalized Exploratory Well Costs		
	2016	2015	2014
	(in millions)		
Balance at January 1,	**$ 2.6**	$ 12.6	$ 2.6
Additions to capitalized exploratory well costs pending the determination of proved reserves	**11.7**	6.0	13.7
Reclassifications to proved properties after the determination of proved reserves	**—**	(16.0)	—
Capitalized exploratory well costs charged to expense	**(0.1)**	—	(3.7)
Balance at December 31,	**$ 14.2**	$ 2.6	$ 12.6

Note 5 – Asset Retirement Obligations

QEP records ARO associated with the retirement of tangible, long-lived assets. The Company's ARO liability applies primarily to abandonment costs associated with oil and gas wells and certain other properties. The fair values of such costs are estimated by Company personnel based on abandonment costs of similar assets and depreciated over the life of the related assets. Revisions to the ARO estimates result from changes in expected cash flows or material changes in estimated asset retirement costs. The ARO liability is adjusted to present value each period through an accretion calculation using a credit-adjusted risk-free interest rate. Of the $231.6 million and $206.8 million ARO liability for the years ended December 31, 2016 and 2015, respectively, $5.8 million and $1.9 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	
	2016	2015
	(in millions)	
ARO liability at January 1,	**$ 206.8**	$ 195.1
Accretion	**8.9**	8.7
Additions[(1)]	**17.0**	3.8
Revisions	**6.5**	17.2
Liabilities related to assets sold	**—**	(16.0)
Liabilities settled	**(7.6)**	(2.0)
ARO liability at December 31,	**$ 231.6**	$ 206.8

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

Note 6 – Fair Value Measurements

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

QEP has determined that its commodity derivative instruments are Level 2. The Level 2 fair value of commodity derivative contracts (see Note 7 – Derivative Contracts) 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, 2016 and 2015, is shown in the table below:

	Fair Value Measurements				
	Gross Amounts of Assets and Liabilities				
	Level 1	Level 2	Level 3	Netting Adjustments[1]	Net Amounts Presented on the Consolidated Balance Sheet
	(in millions)				
	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**
	December 31, 2015				
Financial Assets					
Fair value of derivative contracts – short-term	$ —	$ 147.8	$ —	$ (1.0)	$ 146.8
Fair value of derivative contracts – long-term	—	23.2	—	—	23.2
Total financial assets	$ —	$ 171.0	$ —	$ (1.0)	$ 170.0
Financial Liabilities					
Fair value of derivative contracts – short-term	$ —	$ 1.8	$ —	$ (1.0)	$ 0.8
Fair value of derivative contracts – long-term	—	4.0	—	—	4.0
Total financial liabilities	$ —	$ 5.8	$ —	$ (1.0)	$ 4.8

[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. See Note 7 – 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, 2016		December 31, 2015	
	(in millions)			
Financial Assets				
Cash and cash equivalents	**$ 443.8**	**$ 443.8**	$ 376.1	$ 376.1
Financial Liabilities				
Checks outstanding in excess of cash balances	**$ 12.3**	**$ 12.3**	$ 29.8	$ 29.8
Long-term debt	**$ 2,020.9**	**$ 2,104.3**	$ 2,191.5	$ 1,784.6

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

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

Nonrecurring Fair Value Measurements

The provisions of the fair value measurement standard are also applied to the Company's nonrecurring measurements. The Company utilizes fair value on a 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, 2016 and 2015, the Company recorded impairments of certain proved oil and gas properties of $1,172.7 million and $39.3 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, proved oil and gas property impairments are considered Level 3 within the fair value hierarchy. See 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: 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. 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. See Note 2 – Acquisitions and Divestitures for additional information on the fair value of acquired properties.

Note 7 – Derivative Contracts

QEP has established policies and procedures for managing commodity price volatility through the use of derivative instruments. In the normal course of business, QEP uses commodity price derivative instruments to reduce the impact of potential downward movements in commodity prices on cash flow, returns on capital investment, and other financial results. However, these instruments typically limit gains from favorable price movements. The volume of production subject to commodity derivative instruments and the mix of the instruments are frequently evaluated and adjusted by management in response to changing market conditions. QEP may enter into commodity derivative contracts for up to 100% of forecasted production, but generally, QEP enters into commodity derivative contracts for approximately 50% to 75% of its forecasted annual production by the end of the first quarter of each fiscal year. In addition, QEP 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 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 collars at 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.

During 2014, QEP also used interest rate swaps to mitigate a portion of its exposure to interest rate volatility risk associated with its $600.0 million term loan. These interest rate swaps were terminated in December 2014 in conjunction with the extinguishment of QEP's term loan.

Derivative Contracts – Production

The following table presents QEP's volumes and average prices for its commodity derivative swap contracts as of December 31, 2016:

Year	Index	Total Volumes		Average Swap Price per Unit
		(in millions)		
Oil sales		(bbls)		($/bbl)
2017	NYMEX WTI	13.5	$	51.39
2018	NYMEX WTI	7.3	$	53.40
Gas sales		(MMBtu)		($/MMBtu)
2017	NYMEX HH	94.9	$	2.86
2017	IFNPCR	32.9	$	2.51
2018	NYMEX HH	62.1	$	2.96

The following table presents QEP's volumes and average prices for its commodity derivative gas collars as of December 31, 2016:

Year	Index	Total Volumes		Average Price Floor		Average Price Ceiling
		(in millions)				
		(MMBtu)		($/MMBtu)		($/MMBtu)
2017	NYMEX HH	11.0	$	2.50	$	3.50

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, 2016:

Year	Index Less Differential	Index	Total Volumes		Weighted-Average Differential
			(in millions)		
Oil sales			(bbls)		($/bbl)
2017	NYMEX WTI	Argus WTI Midland	2.9	$	(0.64)
2018	NYMEX WTI	Argus WTI Midland	2.2	$	(0.90)
Gas sales			(MMBtu)		($/MMBtu)
2017	NYMEX HH	IFNPCR	51.1	$	(0.18)
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, 2016:

Year	Type of Contract	Index	Total Volumes		Average Swap Price per Unit
			(in millions)		
Gas sales			(MMBtu)		($/MMBtu)
2017	SWAP	IFNPCR	4.0	$	2.88

QEP Derivative Financial Statement Presentation

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

		Gross asset derivative instruments fair value		Gross liability derivative instruments fair value	
		December 31,			
	Balance Sheet line item	**2016**	2015	**2016**	2015
		(in millions)			
Current:					
Commodity	Fair value of derivative contracts	**$ —**	$ 147.8	**$ 169.8**	$ 1.8
Long-term:					
Commodity	Fair value of derivative contracts	**—**	23.2	**32.0**	4.0
Total derivative instruments		**$ —**	$ 171.0	**$ 201.8**	$ 5.8

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 instruments not designated as cash flow hedges	**2016**	2015	2014
Realized gains (losses) on commodity derivative contracts	(in millions)		
Production			
Oil derivative contracts	**$ 86.3**	$ 353.7	$ 15.7
Gas derivative contracts	**44.8**	103.4	(16.7)
Gas Storage			
Gas derivative contracts	**2.9**	3.8	(2.5)
Total realized gains (losses) on commodity derivative contracts	**134.0**	460.9	(3.5)
Unrealized gains (losses) on commodity derivative contracts			
Production			
Oil derivative contracts	**(217.2)**	(244.9)	299.8
Gas derivative contracts	**(145.4)**	62.0	68.4
Gas Storage			
Gas derivative contracts	**(4.4)**	(0.8)	4.2
Total unrealized gains (losses) on commodity derivative contracts	**(367.0)**	(183.7)	372.4
Total realized and unrealized gains (losses) on commodity derivative contracts	**$ (233.0)**	$ 277.2	$ 368.9
Realized gains (losses) on interest rate swaps			
Realized gains (losses) on interest rate swaps	**$ —**	$ —	$ (7.6)
Unrealized gains (losses) on interest rate swaps			
Unrealized gains (losses) on interest rate swaps	**—**	—	2.0
Total realized and unrealized gains (losses) on interest rate swaps	**—**	—	(5.6)
Total net realized gains (losses) on derivative contracts	**134.0**	460.9	(11.1)
Total net unrealized gains (losses) on derivative contracts	**(367.0)**	(183.7)	374.4
Grand Total	**$ (233.0)**	$ 277.2	$ 363.3

Note 8 – 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 does not expect to incur additional costs related to the 2016 restructuring.

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 does not expect to incur additional costs related to the closure of its Tulsa office.

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

Note 9 – Debt

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

	December 31,	
	2016	2015
	(in millions)	
Revolving Credit Facility due 2019	**$ —**	$ —
6.05% Senior Notes due 2016[1]	**—**	176.8
6.80% Senior Notes due 2018	**134.0**	134.0
6.80% Senior Notes due 2020	**136.0**	136.0
6.875% Senior Notes due 2021	**625.0**	625.0
5.375% Senior Notes due 2022	**500.0**	500.0
5.25% Senior Notes due 2023	**650.0**	650.0
Less: unamortized discount and unamortized debt issuance costs	**(24.1)**	(30.3)
Total principal amount of debt (including current portion)	**2,020.9**	2,191.5
Less: current portion of long-term debt	**—**	(176.8)
Total long-term debt outstanding	**$ 2,020.9**	$ 2,014.7

(1) During the year ended December 31, 2016, the Company paid $176.8 million for the repayment of the 6.05% Senior Notes, which were due on September 1, 2016.

Of the total debt outstanding on December 31, 2016, the 6.80% Senior Notes due April 1, 2018, the 6.80% Senior Notes due March 1, 2020 and the 6.875% Senior Notes due March 1, 2021, will mature within the next five years. In addition, the revolving credit facility matures on December 2, 2019.

Credit Facility

QEP's revolving credit facility, which matures in December 2019, provides for loan commitments of $1.8 billion from a group of financial institutions. The credit facility provides for borrowings at short-term interest rates and contains customary provisions and restrictions. The credit agreement contains financial covenants (that are defined in the credit agreement) that limit the amount of debt the Company may 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 quarters ending on and prior to December 31, 2017, and 3.75 times thereafter and (iii) a present value coverage ratio under which, during a ratings trigger period, require that 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, 2018, and 1.50 times at any time on or after January 1, 2018. At December 31, 2016 and 2015, QEP was in compliance with the covenants under the credit agreement.

During the years ended December 31, 2016 and 2015, QEP had no borrowings outstanding under the credit facility. At December 31, 2016 and 2015, QEP had $2.8 million and $3.4 million, respectively, in letters of credit outstanding under the credit facility.

Senior Notes
At December 31, 2016, the Company had $2,045.0 million principal amount of senior notes outstanding with maturities ranging from April 2018 to May 2023 and coupons ranging from 5.25% to 6.875%. The senior notes pay interest semi-annually, are unsecured senior obligations and rank equally with all of our other existing and future unsecured and senior obligations. QEP may redeem some or all of its senior notes at any time before their maturity at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. The indentures governing QEP's senior notes contain customary events of default and covenants that may limit QEP's ability to, among other things, place liens on its property or assets.

Note 10 – Commitments and Contingencies

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

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

Litigation

Rocky Mountain Resources Lawsuit – Rocky Mountain Resources, LLC (Rocky Mountain) filed a complaint against the Company in March 2011, seeking determination of the existence of a 4% overriding royalty interest in an oil and gas lease. Rocky Mountain alleged that the defendants failed to pay Rocky Mountain monies associated with the claimed 4% overriding royalty interest since the issuance of the lease by the State of Wyoming in 1980. In February 2015, a jury rendered a verdict against the Company and awarded Rocky Mountain damages in the amount of $16.7 million, including interest. The Company appealed the verdict to the Wyoming Supreme Court and in February 2017, the Wyoming Supreme Court reversed and remanded the case back to the trial court with instructions to enter judgment in favor of the Company. The Company had been depositing monthly revenues attributable to the contested overriding royalty interest with the Court as such amounts became due and payable. These deposits are presented within "Prepaid expenses and other" on the Company’s Consolidated Balance Sheets. Based upon the favorable ruling from the Wyoming Supreme Court, the Company will file a motion with the trial court seeking the release of the escrowed funds.

Claims of Former Limited Partners – The Company received a demand from certain former limited partners of terminated drilling partnerships of the Company (acting as the general partner). The former limited partners allege that distributions to which they were entitled from the drilling partnerships were not made or were calculated incorrectly. Other former limited partners may assert claims. No litigation has been filed, and the Company is in the process of evaluating the allegations and its defenses.

Department of Interior Investigation regarding Indian Royalties – Pursuant to regulations published by the Office of Natural Resources Revenue (ONRR) of the Department of the Interior (DOI), certain of the Company’s Indian leases are subject to “dual accounting” and “major portion” requirements. The Company must initially report royalties on production from these leases based upon its actual sales arrangements and, once ONRR publishes the major portion price (approximately 18 months after a calendar year), the Company must recalculate its previously reported royalties for the applicable calendar year and pay additional royalties if the dual accounting or major portion pricing results in higher royalties. In July 2016, the Company was notified that the Office of Inspector General of the DOI is conducting an investigation of the Company’s compliance with ONRR dual accounting and major portion requirements to recalculate royalties for 2013 on production from certain Indian leases. As the investigation continues, there may be penalties imposed.

EPA Request for Information – In July 2015, QEP received an information request from the Environmental Protection Agency (EPA) pursuant to Section 114(a) of the Clean Air Act. The information request sought facts and data about certain tank batteries in QEP’s Williston Basin operations. QEP timely responded to the information requests. In August 2016, the EPA requested a conference to review this matter. In addition, since February 2016, the North Dakota Department of Health (NDDH) has engaged with the oil and gas production industry in North Dakota to address potential noncompliance associated with emissions from tank batteries. QEP has participated in these discussions. While no formal federal or state enforcement action has been commenced in connection with the tank batteries to date, other operators have been assessed penalties following similar information requests. QEP anticipates that resolution of these matters will likely result in penalties and require QEP to incur additional capital expenditures to correct noncompliance issues.

To the extent that the Company can reasonably estimate losses for contingencies where the risk of a material loss (in excess of accruals, if any) is reasonably possible, the Company estimates such losses could total between zero and approximately $25.0 million.

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
2017	$	130.7
2018	$	111.9
2019	$	104.5
2020	$	87.8
2021	$	51.0
After 2021	$	207.8

QEP rents office space throughout its scope of operations from third-party lessors. Rental expense from operating leases amounted to $9.1 million, $8.0 million, and $8.2 million during the years ended December 31, 2016, 2015 and 2014, 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
2017	$	8.7
2018	$	7.2
2019	$	7.1
2020	$	6.9
2021	$	7.0
After 2021	$	11.2

Note 11 – 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 7.1 million shares available for future grants under the LTSIP at December 31, 2016.

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. In addition, during the year ended December 31, 2014, QEP recognized $5.8 million in total compensation expense related to discontinued operations (including compensation expense related to the QEP Midstream Long Term Incentive Plan) which is reflected within "Net income from discontinued operations, net of income tax" on the Consolidated Statement of Operations.

	Year Ended December 31,		
	2016	2015	2014
	(in millions)		
Stock options	**$ 2.3**	$ 2.9	$ 3.3
Restricted share awards	**23.7**	25.6	18.1
Performance share units	**9.4**	6.2	0.7
Restricted share units	**0.2**	—	—
Total share-based compensation expense	**$ 35.6**	$ 34.7	$ 22.1

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 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,		
	2016	2015	2014
Weighted-average grant date fair value of awards granted during the period	**$ 3.77**	$ 6.82	$ 10.11
Risk-free interest rate range	**0.99% - 1.15%**	1.38% - 1.38%	1.31% - 1.34%
Weighted-average risk-free interest rate	**1.2%**	1.4%	1.3%
Expected price volatility range	**43.42% - 43.66%**	36.8% - 36.8%	36.1% - 37.3%
Weighted-average expected price volatility	**43.4%**	36.8%	37.1%
Expected dividend yield	**—%**	0.37%	0.25%
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, 2015	2,200,776	$ 27.94		
Granted	**438,180**	**10.14**		
Canceled	**(486,999)**	**23.77**		
Outstanding at December 31, 2016	**2,151,957**	**$ 25.26**	**3.66**	**$ 3.6**
Options Exercisable at December 31, 2016	**1,385,753**	**$ 30.18**	**2.61**	**$ 0.1**
Unvested Options at December 31, 2016	**766,204**	**$ 16.38**	**5.57**	**$ 3.5**

During the year ended December 31, 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 and $0.6 million during the years ended December 31, 2015 and 2014, respectively. The Company realized an income tax benefit of $0.2 million for the year ended December 31, 2016, $6.4 million of income tax expense for the year ended December 31, 2015, and there was no income tax impact for the year ended December 31, 2014. Stock options increased the Company's Additional Paid-in-Capital (APIC) pool by $0.3 million as of December 31, 2016. As of December 31, 2016, $1.2 million of unrecognized compensation cost related to stock options granted under the LTSIP, which is included within "Additional paid-in capital" on the Consolidated Balance Sheet, is expected to be recognized over a weighted-average period of 1.84 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 total fair value of restricted share awards that vested during the years ended December 31, 2016, 2015 and 2014, was $24.3 million, $22.7 million and $26.8 million, respectively. There was no income tax impact for the year ended December 31, 2016. The Company realized an income tax benefit of $3.2 million for the year ended December 31, 2015, and an income tax expense $0.5 million for the year ended December 31, 2014. Restricted share awards increased the Company's APIC pool by $3.5 million as of December 31, 2016. The weighted-average grant date fair value of restricted share awards granted was $10.50 per share, $20.92 per share and $31.40 per share for the years ended December 31, 2016, 2015 and 2014, respectively. As of December 31, 2016, $17.5 million of unrecognized compensation cost related to restricted share awards granted under the LTSIP, which is included within "Additional paid-in capital" on the Consolidated Balance Sheet, is expected to be recognized over a weighted-average vesting period of 1.98 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, 2015	2,008,210	$ 24.18
Granted	**2,467,954**	**10.50**
Vested	**(973,307)**	**25.01**
Forfeited	**(294,354)**	**14.26**
Unvested balance at December 31, 2016	**3,208,503**	**$ 14.32**

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 delivered 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, 2016, 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 Sheet. As these awards are dependent upon the Company's total shareholder return and stock price, they are measured at fair value at the end of each reporting period. The Company paid $2.8 million, $3.1 million and $1.7 million for vested performance share units related to continuing operations during the years ended December 31, 2016, 2015 and 2014, respectively. In addition, during the year ended December 31, 2014, the Company paid $0.5 million for vested performance share units related to discontinued operations. The weighted-average grant date fair value of the performance share units granted during the years ended December 31, 2016, 2015 and 2014, were $10.16, $21.69, and $31.57 per share, respectively. As of December 31, 2016, $12.3 million of unrecognized compensation cost, which represents the unvested portion of the fair market value of performance shares granted, is expected to be recognized over a weighted-average vesting period of 1.85 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, 2015	630,786	$ 27.50
Granted	**597,185**	**10.16**
Vested and paid out	**(178,169)**	**30.07**
Forfeited	**(22,522)**	**15.16**
Unvested balance at December 31, 2016	**1,027,280**	**$ 17.24**

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 Sheet 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 $10.12 per share for the year ended December 31, 2016. As of December 31, 2016, $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 1.32 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, 2015	—	$ —
Granted	**21,493**	**10.12**
Vested	**(193)**	**10.12**
Forfeited	**(3,266)**	**10.12**
Unvested balance at December 31, 2016	**18,034**	**$ 10.12**

Note 12 – 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, 2016, covers 41 active and suspended participants, or 6%, of QEP's active employees, and 173 participants that are retired or were terminated and vested. Pension Plan 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 retirement. During the year ended December 31, 2016, 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 2017. Contributions to the Pension Plan increase plan assets.

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 be qualified under the Internal Revenue Services' participant rules. 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. This change resulted in a non-cash curtailment loss of $11.2 million recognized on the Consolidated Statement of Operations within "General and administrative" 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 retirement. During the year ended December 31, 2016, the Company made contributions of $3.2 million to its SERP and expects to contribute approximately $2.5 million in 2017. Contributions to the SERP are used to fund current benefit payments. The SERP was amended and restated in June 2015 and was closed to new participants effective January 1, 2016.

The Medical Plan is unfunded and provides other postretirement benefits including certain health care and life insurance benefits for certain retired QEP employees. The Medical Plan is provided only to employees hired before January 1, 1997. Of the 41 active, pension eligible employees, 25 are also eligible for the Medical Plan when they retire. As of December 31, 2016, 50 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, 2016, the Company made contributions of $0.4 million and expects to contribute approximately $0.3 million of benefits in 2017. At December 31, 2016 and 2015, QEP's accumulated benefit obligation exceeded the fair value of its qualified retirement plan assets.

During the year ended December 31, 2014, the Company recognized a $10.7 million loss on curtailment and $1.9 million in expenses for special termination benefits in connection with the Midstream Sale (see Note 3 – Discontinued Operations) and the 2014 property sales in the Other Southern area (see Note 2 – Acquisitions and Divestitures). The Pension Plan was amended to provide certain termination benefits for participants impacted by the Midstream Sale and the 2014 property sales in the Other Southern area who were aged 50-54 as of the date of their separation from the Company. These expenses are included within "Net income from discontinued operations, net of income tax" and "Net gain (loss) from asset sales" for the year ended December 31, 2014, on the Consolidated Statements of Operations.

The accumulated benefit obligation for all defined-benefit pension plans was $124.5 million and $117.4 million at December 31, 2016 and 2015, 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, 2016 and 2015, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2016 and 2015:

	Pension Plan and SERP benefits		Medical Plan benefits	
	2016	2015	**2016**	2015
Change in benefit obligation	(in millions)			
Benefit obligation at January 1,	**$ 120.3**	$ 132.6	**$ 5.2**	$ 6.6
Service cost	**1.2**	2.1	**—**	—
Interest cost	**5.2**	4.9	**0.2**	0.2
Curtailments	**—**	(7.1)	**—**	—
Benefit payments	**(7.8)**	(7.7)	**(0.4)**	(0.2)
Plan amendments	**—**	0.9	**—**	—
Actuarial loss (gain)	**10.3**	(5.4)	**0.4**	(1.4)
Benefit obligation at December 31,	**$ 129.2**	$ 120.3	**$ 5.4**	$ 5.2
Change in plan assets				
Fair value of plan assets at January 1,	**$ 79.3**	$ 81.4	**$ —**	$ —
Actual return on plan assets	**7.4**	(1.9)	**—**	—
Company contributions to the plan	**7.2**	7.5	**0.4**	0.2
Benefit payments	**(7.8)**	(7.7)	**(0.4)**	(0.2)
Fair value of plan assets at December 31,	**86.1**	79.3	**—**	—
Underfunded status (current and long-term)	**$ (43.1)**	$ (41.0)	**$ (5.4)**	$ (5.2)
Amounts recognized in balance sheets				
Accounts payable and accrued expenses	**$ (2.5)**	$ (2.9)	**$ (0.3)**	$ (0.3)
Other long-term liabilities	**(40.6)**	(38.1)	**(5.1)**	(4.9)
Total amount recognized in balance sheet	**$ (43.1)**	$ (41.0)	**$ (5.4)**	$ (5.2)
Amounts recognized in AOCI				
Net actuarial loss (gain)	**$ 23.5**	$ 15.8	**$ (0.4)**	$ (0.8)
Prior service cost	**2.9**	4.1	**1.0**	1.2
Total amount recognized in AOCI	**$ 26.4**	$ 19.9	**$ 0.6**	$ 0.4

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		
	2016	2015	2014	**2016**	2015	2014
Components of net periodic benefit cost	(in millions)					
Service cost	**$ 1.2**	$ 2.1	$ 2.6	**$ —**	$ —	$ —
Interest cost	**5.2**	4.9	5.3	**0.2**	0.2	0.3
Expected return on plan assets	**(5.6)**	(5.7)	(5.1)	**—**	—	—
Curtailment loss	**—**	11.2	9.3	**—**	—	1.4
Special termination benefits	**—**	—	1.9	**—**	—	—
Settlements	**—**	—	0.7	**—**	—	—
Amortization of prior service costs	**1.1**	1.7	4.7	**0.2**	0.2	0.3
Amortization of actuarial loss	**0.8**	0.5	0.8	**—**	—	—
Periodic expense	**$ 2.7**	$ 14.7	$ 20.2	**$ 0.4**	$ 0.4	$ 2.0
Components recognized in accumulated other comprehensive income						
Current period prior service cost	**$ —**	$ 0.9	$ —	**$ —**	$ —	$ —
Current period actuarial (gain) loss	**8.5**	2.2	21.5	**0.4**	(1.4)	0.6
Amortization of prior service cost	**(1.1)**	(12.9)	(14.0)	**(0.2)**	(0.2)	(1.7)
Amortization of actuarial gain (loss)	**(0.8)**	(0.5)	(0.8)	**—**	—	—
Loss on curtailment in current period	**—**	(7.1)	(8.2)	**—**	—	(0.2)
Settlements	**—**	—	(0.7)	**—**	—	—
Total amount recognized in accumulated other comprehensive income	**$ 6.6**	$ (17.4)	$ (2.2)	**$ 0.2**	$ (1.6)	$ (1.3)

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 2017 is $2.2 million, which represents amortization of prior service cost recognition and actuarial losses. The estimated portion to be recognized in net periodic cost for the Medical Plan from AOCI in 2017 is $0.2 million, which represents amortization of prior service cost recognition. Amortization of prior service costs and actuarial gains or losses out of AOCI are recognized in the Consolidated Statements of Operations in "General and administrative" 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, 2016 and 2015:

	Pension Plan and SERP benefits		Medical Plan benefits	
	2016	2015	**2016**	2015
Discount rate	**3.96%**	4.24%	**4.10%**	4.40%
Rate of increase in compensation[(1)]	**3.50%**	4.00%	**3.50%**	4.00%

(1) The Pension Plan was frozen effective January 1, 2016, and as a result, the rate of increase in compensation for participants is no longer considered an assumption used by the Company to calculate the value of the Pension Plan. As such, for the year ended December 31, 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		
	2016	2015	2014	**2016**	2015	2014
Discount rate	**4.23%**	3.94%	4.40%	**4.40%**	4.00%	5.00%
Expected long-term return on plan assets	**6.50%**	6.75%	7.00%	**n/a**	n/a	n/a
Rate of increase in compensation[(1)]	**4.00%**	4.00%	4.00%	**4.00%**	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 year ended December 31, 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 2017. 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.

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 and significant to the fair value measurement. 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, 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, 2016 and 2015, respectively:

	December 31, 2016		December 31, 2015	
	Total	**Percentage of total**	Total	Percentage of total
	(in millions, except percentages)			
Cash and short-term investments	**$ 3.5**	**4%**	$ 0.4	—%
Equity securities:				
Domestic	**39.3**	**46%**	38.5	49%
International	**21.6**	**25%**	16.8	21%
Fixed income	**21.7**	**25%**	23.6	30%
Total investments	**$ 86.1**	**100%**	$ 79.3	100%

Expected Benefit Payments
As of December 31, 2016, the following future benefit payments are expected to be paid:

	Pension Plan and SERP benefits	Medical Plan benefits
	(in millions)	
2017	$ 7.2	$ 0.3
2018	$ 6.6	$ 0.3
2019	$ 8.6	$ 0.3
2020	$ 8.0	$ 0.3
2021	$ 8.9	$ 0.3
2022 through 2026	$ 42.3	$ 1.4

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. For the year ended December 31, 2016, all employees not covered by the SERP were eligible for matching contributions equal to 100% of the employees' contributions up to a maximum of 8% of their qualifying earnings. For the year ended December 31, 2016, employees covered by the SERP were eligible for matching contributions equal to 100% of the employee's contributions up to a maximum of 6% of their qualifying earnings. For the years ended December 31, 2015 and 2014, the Company made matching contributions for employees not covered by the Pension Plan or the SERP equal to 100% of employees' contributions up to a maximum of 8% of their qualifying earnings. For the years ended December 31, 2015 and 2014, employees covered by the Pension Plan or the SERP were eligible for matching contributions equal to 100% of the employees' contributions up to a maximum of 6% match of their qualifying earnings. 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 $5.6 million, $6.3 million and $7.6 million during the years ended December 31, 2016, 2015 and 2014, respectively.

Note 13 – Income Taxes

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,		
	2016	2015	2014
Federal income tax provision (benefit)	(in millions)		
Current	**$ (55.5)**	$ (112.3)	$ (324.0)
Deferred	**(614.3)**	34.5	110.3
State income tax provision (benefit)			
Current	**(1.5)**	(6.6)	(15.5)
Deferred	**(36.9)**	(9.2)	(3.3)
Total income tax provision (benefit)	**$ (708.2)**	$ (93.6)	$ (232.5)

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,		
	2016	2015	2014
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	**2.4 %**	4.2 %	(1.5)%
State rate change	**(1.1)%**	— %	3.4 %
Penalties	**— %**	(0.3)%	— %
Return to provision adjustment	**— %**	(0.3)%	(0.4)%
Other	**— %**	(0.1)%	(0.3)%
Effective income tax rate	**36.3 %**	38.5 %	36.2 %

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

	December 31,			
	2016		2015	
Deferred tax liabilities	(in millions)			
Property, plant and equipment	**$**	**1,135.0**	$	1,531.0
Commodity price derivatives		**—**		60.4
Total deferred tax liabilities		**1,135.0**		1,591.4
Deferred tax assets				
Net operating loss and tax credit carryforwards	**$**	**161.6**	$	51.9
Employee benefits and compensation costs		**49.0**		43.6
Bonus and vacation accrual		**11.4**		7.0
Commodity price derivatives		**74.3**		—
Other		**12.8**		9.1
Total deferred tax assets		**309.1**		111.6
Net deferred income tax liability	**$**	**825.9**	$	1,479.8
Balance sheet classification				
Deferred income tax liability – noncurrent		**825.9**		1,479.8
Net deferred income tax liability	**$**	**825.9**	$	1,479.8

The amounts and expiration dates of net operating loss and tax credit carryforwards at December 31, 2016, are as follows:

	Expiration Dates	Amounts	
		(in millions)	
State net operating loss and tax credit carryforwards	2017-2033	**$**	**53.6**
State net operating loss valuation allowance			**(20.6)**
U.S. net operating loss	2036		**109.1**
U.S. alternative minimum tax credit	Indefinite		**19.5**
Total		**$**	**161.6**

The valuation allowance of $20.6 million was established in 2014 against the available state net operating loss and is related primarily to losses incurred in Oklahoma. 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.

Unrecognized Tax Benefit
As of December 31, 2016 and 2015, QEP had $15.6 million 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 Sheet. The uncertain tax positions the Company reported during the year ended December 31, 2016 and 2015, were expensed during the year ended December 31, 2014. 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 Statement 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, 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.

The following is a reconciliation of our beginning and ending amounts of unrecognized tax benefits for the years ended December 31, 2016 and 2015:

	Unrecognized Tax Benefits	
	2016	2015
	(in millions)	
Balance as of January 1,	**$ 15.6**	$ —
Additions for tax positions taken during the current period	**—**	15.6
Balance as of December 31,	**$ 15.6**	$ 15.6

As of December 31, 2016 and 2015, QEP had approximately $15.6 million of unrecognized tax benefit that would impact its effective tax rate if recognized.

Note 14 – Quarterly Financial Information (unaudited)

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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2016	(in millions, except per share amounts or otherwise specified)				
Revenues	**$ 261.3**	**$ 333.7**	**$ 382.4**	**$ 399.7**	**$ 1,377.1**
Operating income (loss)	**(1,379.2)**	**(92.9)**	**(93.6)**	**(36.9)**	**(1,602.6)**
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)	**13,766.4**	**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**
2015					
Revenues	$ 468.1	$ 574.6	$ 507.6	$ 468.3	$ 2,018.6
Operating income (loss)	(128.6)	(16.7)	(87.7)	(144.6)	(377.6)
Net income (loss)	(55.6)	(76.3)	21.1	(38.6)	(149.4)
Net gain (loss) from asset sales and impairment	(50.5)	24.0	(2.1)	(22.4)	(51.0)
Nonrecurring items in operating income (loss)[(1)]	—	11.2	—	—	11.2
Per share information					
Basic EPS	$ (0.32)	$ (0.43)	$ 0.12	$ (0.22)	$ (0.85)
Diluted EPS	(0.32)	(0.43)	0.12	(0.22)	(0.85)
Production information					
Total equivalent production (Mboe)	12,528.8	13,484.3	14,462.4	13,986.6	54,462.1
Total equivalent production (Bcfe)	75.2	80.9	86.7	84.0	326.8

(1) Reflects legal expenses and loss contingencies incurred during the year ended December 31, 2016, and a non-cash pension curtailment incurred during the year ended December 31, 2015.

Note 15 – Supplemental Oil and Gas Information (unaudited)

The Company is making the following supplemental disclosures of oil and gas producing activities, in accordance with ASC 932, *Extractive Activities – Oil and Gas*, as amended by ASU 2010-03, *Oil and Gas Reserve Estimation and Disclosures*, and SEC Regulation S-X. The Company uses the successful efforts accounting method for its oil and gas exploration and development activities. 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,	
	2016	2015
	(in millions)	
Proved properties	**$ 14,232.5**	$ 13,314.9
Unproved properties, net	**871.5**	691.0
Total proved and unproved properties	**15,104.0**	14,005.9
Accumulated depreciation, depletion and amortization	**(8,797.7)**	(6,870.2)
Net capitalized costs	**$ 6,306.3**	$ 7,135.7

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 $34.6 million and ARO additions and revisions of $23.5 million during the year ended December 31, 2016. The costs incurred to advance the development of reserves that were classified as proved undeveloped were approximately $258.1 million in 2016, $490.4 million in 2015, and $792.9 million in 2014. The costs incurred in 2016 related to the drilling and completion of PUD locations in QEP's operating areas were reduced from historical levels in conjunction with our efforts to reduce drilling and completion activities in 2016 due to lower commodity prices.

	Year Ended December 31,		
	2016	2015	2014
	(in millions)		
Proved property acquisitions	**$ 431.6**	$ 49.6	$ 465.4
Unproved property acquisitions	**208.7**	39.8	496.3
Exploration (capitalized and expensed)	**13.4**	8.7	23.6
Development	**509.2**	1,010.3	1,695.1
Total costs incurred	**$ 1,162.9**	$ 1,108.4	$ 2,680.4

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,		
	2016	2015	2014
	(in millions)		
Revenues	**$ 1,271.0**	$ 1,390.4	$ 2,374.6
Production costs	**616.7**	654.1	735.6
Exploration expenses	**1.7**	2.7	9.9
Depreciation, depletion and amortization	**852.3**	870.8	984.4
Impairment	**1,194.3**	55.6	1,143.2
Total expenses	**2,665.0**	1,583.2	2,873.1
Income (loss) before income taxes	**(1,394.0)**	(192.8)	(498.5)
Income tax benefit (expense)	**517.2**	70.6	182.5
Results of operations from producing activities excluding allocated corporate overhead and interest expenses	**$ (876.8)**	$ (122.2)	$ (316.0)

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, 2016, and retained RSC and DeGolyer and MacNaughton to prepare the estimates of all of its proved reserves as of December 31, 2015 and 2014. 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, 2016, 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 leasehold 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, 2016, 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, 2014, 2015 and 2016 are as follows:

	Oil	Gas	NGL	Total[13]
	(MMbbl)	(Bcf)	(MMbbl)	(MMboe)
Balance at December 31, 2013	148.6	2,554.9	102.6	677.0
Revisions of previous estimates[1]	(4.0)	27.1	1.4	1.9
Extensions and discoveries[2]	16.8	141.4	8.6	49.0
Purchase of reserves in place[3]	35.7	72.5	12.3	60.1
Sale of reserves in place[4]	(7.5)	(299.4)	(21.5)	(78.9)
Production	(17.1)	(179.3)	(6.8)	(53.8)
Balance at December 31, 2014	172.5	2,317.2	96.6	655.3
Revisions of previous estimates[5]	(47.0)	(463.8)	(55.3)	(179.6)
Extensions and discoveries[6]	85.6	467.7	21.8	185.4
Purchase of reserves in place[7]	2.0	3.2	0.6	3.1
Sale of reserves in place[8]	(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[9]	**(9.7)**	**412.8**	**(0.3)**	**58.8**
Extensions and discoveries[10]	**13.0**	**158.1**	**3.3**	**42.6**
Purchase of reserves in place[11]	**62.7**	**54.6**	**11.5**	**83.3**
Sale of reserves in place[12]	**(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**
Proved developed reserves				
Balance at December 31, 2013	71.8	1,406.3	52.8	359.0
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**
Proved undeveloped reserves				
Balance at December 31, 2013	76.8	1,148.6	49.8	318.0
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**

(1) Revisions of previous estimates in 2014 include 41.4 MMboe negative performance revisions partially offset by positive other revisions of 33.0 MMboe, operating cost revisions of 6.5 MMboe and pricing revisions of 3.8 MMboe. Negative performance revisions were driven by a 32.3 MMboe decrease in Pinedale reserves related to downward forecast revisions on proved developed (PDP) wells, additional production history on PUD to PDP performance and a downward adjustment in the number of PUD locations. Other negative revisions related to adjustments to shrink and lease operating expense. Pricing revisions were primarily due to increased gas prices, which increased reserves by 3.7 MMboe.

(2) Extensions and discoveries in 2014 increased proved reserves by 49.0 MMboe, primarily related to extensions and discoveries in Pinedale of 22.3 MMboe and the Williston Basin of 20.6 MMboe. All of these extensions and discoveries related to new well completions and associated new PUD locations as well as new compression well projections in Pinedale.

(3) Purchase of reserves in place in 2014 relate to the Company's 2014 Permian Basin Acquisition as discussed in Note 2 – Acquisitions and Divestitures.

(4) Sale of reserves in place primarily related to property sales in the Other Southern area in the second and fourth quarters of 2014 as discussed in Note 2 – Acquisitions and Divestitures.

(5) 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.
(6) 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.
(7) Purchase of reserves in place in 2015 related to the acquisition of additional interests in QEP operated wells in the Williston Basin as discussed in Note 2 – Acquisitions and Divestitures.
(8) 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.
(9) 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.
(10) Extensions and discoveries in 2016 were primarily in the Permian and Uinta basins and related to new well completions and associated new PUD locations.
(11) Purchase of reserves in place in 2016 relate primarily to the Company's 2016 Permian Basin Acquisition as discussed in Note 2 – Acquisitions and Divestitures.
(12) Sale of reserves in place in 2016 relate to the divestiture of QEP's interest in certain non-core properties as discussed in Note 2 – Acquisitions and Divestitures.
(13) Proved reserves include gas reserves that QEP expects to produce and use as field fuel.

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

Future net cash flows were calculated at December 31, 2016, 2015 and 2014, 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 2016, 2015 and 2014, 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,		
	2016	2015	2014
Average benchmark price per unit:			
Oil price (per bbl)	**$ 42.75**	$ 50.28	$ 94.99
Gas price (per MMBtu)	**$ 2.48**	$ 2.59	$ 4.35

Year-end 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 $503.0 million in 2017, $717.3 million in 2018 and $781.3 million in 2019. 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, if needed, availability under its revolving credit facility will be sufficient to cover these estimated future development costs.

The assumptions used to derive the standardized measure of discounted future net cash flows are those required by accounting standards and do not necessarily reflect the Company's expectations. The information may be useful for certain comparative purposes but should not be solely relied upon in evaluating QEP or its performance. Furthermore, information contained in the following table may not represent realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company's reserves. Management believes that the following factors should be considered when reviewing the information below:

- Future commodity prices received for selling the Company's net production will likely differ from those required to be used in these calculations.
- Future operating and capital costs will likely differ from those required to be used in these calculations.
- 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,		
	2016	2015	2014
		(in millions)	
Future cash inflows	**$ 16,239.8**	$ 15,325.3	$ 28,167.3
Future production costs	**(7,789.0)**	(7,389.9)	(9,842.1)
Future development costs	**(3,432.9)**	(2,202.5)	(3,521.3)
Future income tax expenses	**(913.4)**	(1,169.3)	(4,304.0)
Future net cash flows	**4,104.5**	4,563.6	10,499.9
10% annual discount for estimated timing of net cash flows	**(2,176.5)**	(2,087.3)	(5,159.9)
Standardized measure of discounted future net cash flows	**$ 1,928.0**	$ 2,476.3	$ 5,340.0

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,		
	2016	2015	2014
		(in millions)	
Balance at January 1,	**$ 2,476.3**	$ 5,340.0	$ 4,383.9
Sales of oil, gas and NGL produced, net of production costs	**(654.3)**	(736.3)	(1,639.0)
Net change in sales prices and in production (lifting) costs related to future production	**(739.4)**	(6,307.8)	726.6
Net change due to extensions and discoveries	**81.8**	1,765.7	979.9
Net change due to revisions of quantity estimates	**122.7**	(1,350.2)	35.9
Net change due to purchases of reserves in place	**256.5**	29.7	695.3
Net change due to sales of reserves in place	**(4.3)**	(48.8)	(1,153.7)
Previously estimated development costs incurred during the period	**374.6**	865.0	867.5
Changes in estimated future development costs	**(476.5)**	560.7	409.6
Accretion of discount	**311.1**	752.9	597.3
Net change in income taxes	**205.4**	1,554.4	(600.3)
Other	**(25.9)**	51.0	37.0
Net change	**(548.3)**	(2,863.7)	956.1
Balance at December 31,	**$ 1,928.0**	$ 2,476.3	$ 5,340.0

Note 16 – Subsequent Event

In 2017 through the date this Annual Report on Form 10-K was filed with the SEC, QEP closed on multiple acquisitions of surface acreage and mineral leases near its existing operations in the Permian Basin for an aggregate purchase price of $37.9 million, which were funded with cash on hand. Final purchase price accounting, if applicable, for these various transactions was not complete at the time this Form 10-K was filed with the SEC, and as such, any applicable disclosures required by ASC Topic 805, *Business Combinations*, have not been made herein. The Company will include any applicable information in future filings with the SEC.

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 Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended), as of December 31, 2016. Based on such evaluation, such officers have concluded that, as of December 31, 2016, 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 Controls over Financial Reporting

There were no changes in the Company's internal controls over financial reporting that occurred during the quarter ended December 31, 2016, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Assessment of Internal Controls over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-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 in the United States of America. 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, 2016, 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, 2016. 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, 2016, which is included in the Consolidated Financial Statements in Item 8 of Part II of this Annual Report on Form 10-K.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by Item 10 concerning QEP's directors and nominees for directors and other corporate governance matters will be presented in the Company's definitive Proxy Statement prepared for the solicitation of proxies in connection with the Company's Annual Meeting of Stockholders scheduled to be held on May 16, 2017, which the Company expects to file with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2016 (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	Certificate of Incorporation dated May 18, 2010 (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 24, 2010)
3.2	Amended and Restated Bylaws, effective December 15, 2016 (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 December 15, 2016)
3.3	Certificate of Elimination with respect to Series A Junior Participating Preferred Stock of QEP Resources, Inc. (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 16, 2012)

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 2018 (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 April 4, 2008)
4.3	Officers' Certificate setting forth the terms of the 6.80% Notes due 2018 (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 April 4, 2008)
4.4	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)
4.5	Officers' Certificate 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)
4.6	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)
4.7	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)
4.8	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)
4.9	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)
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), and 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)
10.2	Term Loan Agreement, dated as of April 18, 2012, among QEP Resources, Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, 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 April 20, 2012), as amended by the First Amendment to Term Loan Agreement, dated as of August 13, 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 August 16, 2013), and the Second Amendment to Term Loan Agreement and Commitment Increase Agreement, dated as of January 31, 2014 (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 May 7, 2014)
10.3	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)
10.4	Tax Matters Agreement, dated as of June 14, 2010, by and between Questar Corporation and QEP Resources, Inc. (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 16, 2010)
10.5	Transition Services Agreement, dated as of June 14, 2010, by and between Questar Corporation and QEP Resources, Inc. (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 June 16, 2010)
10.6+	Deferred Compensation Plan for Directors, effective as of February 23, 2015 (incorporated by reference to Exhibit 10.10 to the Company's Annual Report on Form 10-K, filed with the Securities and Exchange Commission on February 24, 2015)

10.7+	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)
10.8+	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)
10.9+	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)
10.10+	Deferred Compensation Wrap Plan, effective as of January 1, 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 August 3, 2015)
10.11+	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)
10.12+	Form of Nonqualified Stock Option Agreement for certain key executives (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), as amended by the Form of Nonqualified Stock Option Agreement for certain key executives (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), and the Form of Nonqualified Stock Option Agreement for certain key executives (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)
10.13+	Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to other officers and key employees (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)
10.14+	Form of Incentive Stock Option Agreement for incentive stock options granted to certain key executives (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 June 29, 2010)
10.15+	Form of Incentive Stock Option Agreement for incentive stock options granted to other officers and key employees (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 June 29, 2010)
10.16+	Form of Restricted Stock Agreement for certain key executives (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 June 29, 2010), as amended by the Form of Restricted Stock Agreement for restricted stock granted to certain key executives (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), and the Form of Restricted Stock Agreement for certain key executives (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 other officers and key employees (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 June 29, 2010)
10.18+	Form of Restricted Stock Agreement for restricted stock granted to non-employee directors (incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on June 29, 2010), as amended and restated by Form of Restricted Stock Agreement for 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	Contribution, Conveyance and Assumption Agreement, dated as of August 14, 2013, by and among QEP Midstream Partners, LP, QEP Midstream Partners GP, LLC, QEP Field Services Company and QEP Midstream Partners Operating, LLC (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 16, 2013)
10.21	Credit Agreement, dated as of August 14, 2013, among QEP Midstream Partners Operating, LLC, as the borrower, QEP Midstream Partners, LP, as the parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders from time to time party thereto (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on November 5, 2013)

10.22+	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)
10.23+	Amendment to Restricted Stock Agreements under the QEP Resources, Inc. Long-Term Stock Incentive Plan Granted to Austin Murr, dated effective as of September 30, 2016, by and between the Company and Austin Murr (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 October 26, 2016)
10.24+	Omnibus Agreement, dated as of August 14, 2013, by and among QEP Midstream Partners, LP, QEP Midstream Partners GP, LLC, QEP Resources, Inc., QEP Field Services Company and QEP Midstream Partners Operating, LLC (incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on November 5, 2013)
10.25+	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)
10.26	Purchase and Sale Agreement, dated December 6, 2013, by and among QEP Energy Company, as purchaser, and EnerVest Holding, L.P., EnerVest Energy Institutional Fund XXI-A, L.P., EnerVest Energy Institutional Fund XII-WIB, L.P., and EnerVest Energy Institutional Fund XII-WIC, L.P., as sellers, as amended by First Amendment to Purchase and Sale Agreement, dated January 31, 2014, by and between EnerVest Holding, L.P. and QEP Energy Company, and the Second Amendment to Purchase and Sale Agreement, dated February 14, 2014, by and between EnerVest Holding, L.P. and QEP Energy Company (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 May 7, 2014)
10.27	Purchase and Sale Agreement, dated May 2, 2014, between QEP Energy Company, as seller, and Cimarex Energy Co., as buyer (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 8, 2014)
10.28	Purchase and Sale Agreement, dated May 5, 2014, between QEP Energy Company, as seller, and EnerVest Energy Institutional Fund XIII-A, L.P., EnerVest Energy Institutional Fund XIII-WIB, L.P., EnerVest Energy Institutional Fund XIII-WIC, L.P., and FourPoint Energy, LLC, as buyer, and EnerVest Ltd. (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 May 8, 2014)
10.29	Purchase and Sale Agreement, dated May 7, 2014, by and among QEP Field Services Company, QEP Midstream Partners GP, LLC, and QEP Midstream Partners Operating LLC, and QEP Midstream Partners, LP (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 May 8, 2014)
10.30	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)
10.31	Membership Interest Purchase Agreement, dated as of October 19, 2014, by and between QEP Field Services Company, as seller, and Tesoro Logistics LP, as purchaser (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 20, 2014), as amended by Amendment No. 1 to Membership Interest Purchase Agreement, dated as of December 2, 2014 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on December 4, 2014)
10.32+	Form of Performance Share Unit Award Agreement under the QEP Resources, Inc. Cash Incentive Plan, for awards 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)
10.33+*	Form of Performance Share Unit Award Agreement under the QEP Resources, Inc. Cash Incentive Plan, for awards to executive officers after 2015
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 Statement 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 22, 2017.

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 22, 2017.

/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
*Phillips S. Baker, Jr.	Director
*David Trice	Director
*M. W. Scoggins	Director
*Julie A. Dill	Director
*Robert F. Heinemann	Director
*William L. Thacker III	Director
February 22, 2017	*By /s/ Charles B. Stanley Charles B. Stanley, Attorney in Fact

Exhibit 10.33

QEP RESOURCES, INC.
CASH INCENTIVE PLAN

PERFORMANCE SHARE UNIT AWARD AGREEMENT

THIS PERFORMANCE SHARE UNIT AWARD AGREEMENT (the "Agreement") is made as of _______________ (the "Effective Date"), between QEP Resources, Inc., a Delaware corporation (the "Company"), and ______________ (the "Grantee").

1. Grant of Performance Share Units. Subject to the terms and conditions of this Agreement and the Company's Cash Incentive Plan (the "Plan"), the Company hereby issues to Grantee the right to receive a number of Performance Share Units calculated in the manner set forth in Appendix A hereto, based on the achievement of one or more Performance Goals that must be attained over a relevant Performance Period, and assuming a target award of ______________ Performance Share Units (the "Target Share Units"). Each Performance Share Unit actually earned and vested in accordance with this Agreement and Appendix A hereto represents the right to receive a cash payment equal to the Fair Market Value of one share of the Company's no par value common stock ("Common Stock"), subject to Section 3 and the other terms and conditions of this Agreement. Terms not defined herein shall have the meanings ascribed to them in the Plan.

2. Vesting; Termination of Employment; Forfeiture.
General. Except as set forth below, the Grantee will vest and become entitled to any Performance Share Units earned in accordance with this Agreement and Appendix A hereto only if the Grantee remains in the continuous employment of the Company and its Affiliates from the Effective Date through the date such earned Performance Share Units are paid in accordance with Section 3 (the "Vest Date").

    a) Termination of Employment. Except as provided in subsections (b) and (c) below, if the Grantee terminates employment with the Company and its Affiliates for any reason prior to the Vest Date, the Grantee shall forfeit any and all interest under this Agreement and shall forfeit the right to receive any Performance Share Units hereunder.

    b) Death, Disability, or Retirement. If the Grantee terminates employment with the Company and its Affiliates on account of death, Disability, or Retirement (as defined below) prior to the last day of the Performance Period, the Grantee shall receive on the Vest Date a *pro rata* portion of the Performance Share Units that would otherwise have been received for the Performance Period, subject to certification by the Committee, in an amount equal to the product of (x) the number of Performance Share Units that would have been earned in accordance with the provisions of Appendix A had Grantee remained in the continuous employment of the Company or its Affiliates through the last day of the Performance Period, *multiplied by* (y) the ratio between (i) the number of full months of employment completed from the first day of the Performance Period to the date of termination of employment and (ii) the number of full months in the Performance Period. If the Grantee terminates employment with the Company and its Affiliates on account of death, Disability, or Retirement on or after the last day of the Performance Period but before the Vest Date, the Grantee shall receive on the Vest Date the Performance Share Units that would have been earned in accordance with the provisions of Appendix A had the Grantee remained in the continuous employment of the Company or its Affiliates through the Vest Date. "Retirement" shall mean Grantee's voluntary termination of employment with the Company and its Affiliates on or after age 55 with at least 10 years of service; provided that such retirement occurs no earlier than 12 months after the first day of the Performance Period, or such other retirement as shall be approved by the Committee in its discretion.

    c) Termination Following a Change in Control. If, upon a Change in Control of the Company or within the three years thereafter, the Grantee's employment is terminated prior to the Vest Date (i) by the Company and its Affiliates for any reason other than Cause (as defined below) or Disability (it being understood that upon termination for Disability, the provisions of paragraph (b) above shall apply) or (ii) by the Grantee for Good Reason (as defined below) within 60 days following the expiration of the cure period afforded the Company to rectify the condition giving rise to Good Reason, the Grantee shall be entitled to receive a payment for the Performance Share Units earned hereunder based on the greater of (A) the level of achievement of the applicable performance goals as of immediately prior to the Change in Control or (B) the level of achievement of the applicable performance goals as of the date of termination of employment (which for administrative convenience may be determined as of the most recently completed calendar quarter). Such payment will be made to the Grantee within 30 days after the Grantee's termination of employment. For purposes of this subsection (c):

i. "Cause" means the Grantee's: (i) willful and continued failure to perform substantially the Grantee's duties with an Employer (other than any such failure resulting from incapacity due to physical or mental illness), following written demand for substantial performance delivered to the Grantee by the Board or the Chief Executive Officer of the Company; or (ii) willful engagement in conduct that is materially injurious to an Employer. For purposes of this definition, no act or failure to act on the part of the Grantee shall be considered "willful" unless it is done, or omitted to be done, by the Grantee without reasonable belief that the Grantee's action or omission was in the best interests of the Grantee's Employer. The Company, acting through the Board, must notify the Grantee in writing that the Grantee's employment is being terminated for "Cause". The notice shall include a list of the factual findings used to sustain the judgment that the Grantee's employment is being terminated for "Cause".

ii. "Good Reason" means any of the following events or conditions that occur without the Grantee's written consent, and that remain in effect after notice has been provided by the Grantee to the Company of such event or condition and the expiration of a 30 day cure period: (i) a material diminution in the Grantee's gross annual base salary (as in effect immediately prior to the Change in Control of the Company), target incentive opportunity under any Annual Cash Incentive Plan or long-term incentive award opportunity under any Long-Term Incentive Plan or Stock Incentive Plan; (ii) a material diminution in the Grantee's authority, duties, or responsibilities; (iii) a material diminution in the authority, duties, or responsibilities of the supervisor to whom the Grantee is required to report, including a requirement that the Grantee report to a corporate officer or employee instead of reporting directly to the Board; (iv) a material diminution in the budget over which the Grantee retains authority; (v) a material change in the geographic location at which the Grantee performs services; or (vi) any other action or inaction that constitutes a material breach by an Employer of the Grantee's employment agreement (if any). The Grantee's notification to the Company must be in writing and must occur within a reasonable period of time, not to exceed 90 days, following the initial existence of the relevant event or condition. For purposes of this definition:

A. "Annual Cash Incentive Plan" means any annual incentive plan, program or arrangement offered by an Employer pursuant to which the Grantee is eligible to receive a cash award, subject in whole or in part to the achievement of performance goals over a period of no more than one year, including without limitation the Plan.

B. "Long-Term Incentive Plan" means any long-term incentive plan, program or arrangement offered by an Employer pursuant to which the Grantee is eligible to receive an award, subject in whole or in part to the achievement of performance goals over a period of more than one year, including without limitation the Plan.

C. "Stock Incentive Plan" means any incentive plan offered by the Company pursuant to which upon or following vesting or exercise, as applicable, the Grantee is entitled to receive shares of the Company's Common Stock, including without limitation the QEP Resources, Inc. 2010 Long-Term Stock Incentive Plan.

3. Payment.

a) General. As soon as practicable after the end of the Performance Period the Committee shall determine and certify the number of Performance Share Units that have been earned in accordance with Appendix A and the terms and conditions of this Agreement. Subject to subsection (b), payment for Performance Share Units shall be made in cash on the Vest Date. The amount distributable shall be based on the average closing Company stock price for the fourth quarter of the final year of the Performance Period. All payments shall be made as soon as administratively practicable after the date on which the Committee determines and certifies the number of Performance Share Units that have been earned, but in all events not later than March 15 of the calendar year following the calendar year in which the Performance Period ends. The foregoing provisions are subject to the terms of any valid and effective deferral election made by the Grantee with respect to the Performance Share Units under the QEP Resources, Inc. Deferred Compensation Wrap Plan.

b) Payment in Shares. Notwithstanding anything in the Plan, this Agreement or in Appendix A to the contrary, in lieu of paying the Performance Share Units in cash as provided in subsection (a), the Committee may elect in its discretion to pay some or all of the Performance Share Units in the form of an equal number of actual shares of the Company's (or its successor's) Common Stock or other applicable securities, which shares of Common Stock or other applicable securities shall be delivered to the Grantee under the Company's 2010 Long-Term Stock Incentive Plan (as it may be amended or restated from time to time, or, to the extent applicable, any future or successor equity compensation plan of the Company).

4. No Rights of a Stockholder. The Grantee shall have no voting or other rights as a stockholder of the Company with respect to this award. The Grantee's right to receive payments earned under this Agreement shall be no greater than the right of any unsecured general creditor of the Company.

5. Adjustments to Performance Share Units. In the event of any stock dividend, extraordinary cash dividend, recapitalization, reorganization, merger, consolidation, split-up, spin-off, combination, exchange of shares, grant of warrants or rights offering to purchase Common Stock at a price materially below fair market value or other similar corporate event affecting the Common Stock, the Committee shall adjust the award issued hereunder in order to preserve the benefits or potential benefits intended to be made available under this Agreement. All adjustments shall be made in the sole and exclusive discretion of the Committee, whose determination shall be final, binding and conclusive. Notice of any adjustment shall be given to Grantee.

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

7. Amendment. Except as provided herein, this Agreement may not be amended or otherwise modified unless evidenced in writing and signed by the Company and Grantee, or as approved by the Committee or its delegate. Notwithstanding any provision in this Agreement to the contrary, including Section 8, an amendment to the Plan that would materially and adversely affect Grantee's rights with respect to the award of Performance Share Units granted hereunder will not be effective with respect to such award.

8. Relationship to Plan. Except to the extent this Agreement provides for the discretionary stock settlement of the Target Share Units, this Agreement shall not alter the terms of the Plan. If there is a conflict between the terms of the Plan and the terms of this Agreement, the terms of the Plan shall prevail, provided, however, that the terms of Section 3(b) of this Agreement shall control over any contrary provision of the Plan. Capitalized terms used in this Agreement but not defined herein shall have the meaning given such terms in the Plan.

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

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

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

12. No Rights to Employment. Nothing contained in this Agreement shall be construed as giving Grantee any right to be retained in the employ of the Company or its Affiliates and this Agreement is limited solely to governing the rights and obligations of Grantee with respect to the Performance Share Units.

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

14. Section 409A. For the avoidance of doubt, the provisions of Section 7(g) of the Plan shall apply to this Agreement and all payments made or to be made in connection with this Agreement.

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

GRANTEE

____
[Name]

QEP RESOURCES, INC.

/s/ Richard J. Doleshek
Richard J. Doleshek
Executive Vice President and Chief Financial Officer

APPENDIX A
TO THE PERFORMANCE SHARE UNIT AWARD AGREEMENT

[To be included with individual grants]

Exhibit 12.1

QEP Resources, Inc.
Ratio of Earnings to Fixed Charges

	Year Ended December 31,				
	2016	2015	2014	2013	2012
Earnings	(in millions)				
Income from continuing operations before income taxes and adjustment for income or loss from equity investees	**$ (1,953.2)**	$ (243.0)	$ (642.0)	$ 112.2	$ 0.5
Add (deduct):					
Fixed charges	**146.2**	148.3	175.6	167.8	128.7
Distributed income from equity investees	**—**	0.1	0.3	0.2	0.1
Capitalized interest	**—**	—	—	(2.0)	(3.4)
Total earnings	**$ (1,807.0)**	$ (94.6)	$ (466.1)	$ 278.2	$ 125.9
Fixed Charges					
Interest expense	**$ 143.2**	$ 145.6	$ 172.9	$ 163.3	$ 122.9
Capitalized interest	**—**	—	—	2.0	3.4
Estimate of the interest within rental expense	**3.0**	2.7	2.7	2.5	2.4
Total Fixed Charges	**$ 146.2**	$ 148.3	$ 175.6	$ 167.8	$ 128.7
Ratio of Earnings to Fixed Charges	**—** (1)	— (2)	— (3)	1.7	1.0

(1) Due to a loss for the year ended December 31, 2016, the ratio coverage was less than 1:1. QEP required additional earnings of $1,953.2 million for the year ended December 31, 2016, to achieve a ratio of 1:1.

(2) Due to a loss for the year ended December 31, 2015, the ratio coverage was less than 1:1. QEP required additional earnings of $243.0 million for the year ended December 31, 2015, to achieve a ratio of 1:1.

(3) Due to a loss for the year ended December 31, 2014, the ratio coverage was less than 1:1. QEP required additional earnings of $642.0 million for the year ended December 31, 2014, to achieve a ratio of 1:1.

Exhibit 21.1

QEP Resources, Inc.
Subsidiaries of the Company

Name	State of Organization
QEP Energy Company(1)	Texas
QEP Marketing Company(1)	Utah
QEP Field Services Company(1)	Delaware
Clear Creek Storage Company, LLC(2)	Utah
Permian Gathering, LLC(2)	Delaware
QEP Oil & Gas Company(2)	Delaware
Wyoming Peak Land Company, LLC(3)	Wyoming
Perry Land Management Co. LLC(4)	Oklahoma
Haynesville Gathering LP(5)	Delaware
Roden Participants, LTD(6)	Texas

(1) 100% owned by QEP Resources, Inc.
(2) 100% owned by QEP Marketing Company
(3) 100% owned by QEP Energy Company
(4) 100% owned by QEP Field Services Company
(5) 99% owned by QEP Oil and Gas Company and 1% owned by QEP Marketing Company
(6) 14% owned by QEP Energy Company

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-202686) and on Form S-8 (No. 333-167726 and No. 333-167727) of QEP Resources, Inc. of our report dated February 22, 2017, relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Houston, Texas
February 22, 2017

Exhibit 23.2

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580 FAX (303) 623-4258
621 SEVENTEENTH STREET SUITE 1550 DENVER, COLORADO 80293 TELEPHONE (303) 623-9147

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

As independent petroleum engineers, we hereby consent to the reference of our appraisal reports relating to the proved gas and oil reserves of QEP Energy Company in the Annual Report on Form 10-K of QEP Resources, Inc. as of the years ended December 31, 2013, 2014, 2015 and 2016 incorporated herein by reference into Registration Statement Nos. 333-202686 on Form S-3, 333-167726 and 333-167727 on Form S-8.

/s/ Ryder Scott Company, L.P.

Ryder Scott Company, L.P.

Denver, Colorado
February 22, 2017

Exhibit 23.3

DEGOLYER AND MACNAUGHTON
5001 SPRING VALLEY VOAD
SUITE 800 EAST
DALLAS, TEXAS 75244

February 22, 2017

QEP Resources, Inc.
1050 17th Street, Suite 800
Denver, Colorado 80265

Ladies and Gentlemen:

As independent petroleum engineers, we hereby consent to the reference of our reports relating to the proved gas and oil reserves of QEP Energy Company in the Annual Report on Form 10-K of QEP Resources, Inc. as of the years ended December 31, 2014 and 2015 incorporated herein by reference into Registration Statement Nos. 333-202686 on Form S-3, 333-167726 and 333-167727 on Form S-8.

Very truly yours,

/s/ DeGolyer and MacNaughton

DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

Exhibit 24

POWER OF ATTORNEY

We, the undersigned directors of QEP Resources, Inc., hereby severally constitute Charles B. Stanley and Richard J. Doleshek, and each of them acting alone, our true and lawful attorneys, with full power to them and each of them to sign for us, and in our names in the capacities indicated below, the Annual Report on Form 10-K for 2016 and any and all amendments to be filed with the Securities and Exchange Commission by QEP Resources, Inc., hereby ratifying and confirming our signatures as they may be signed by the attorneys appointed herein to the Annual Report on Form 10-K for 2016 and any and all amendments to such Report.

Witness our hands on the respective dates set forth below.

Signature	Title	Date
/s/ Charles B. Stanley Charles B. Stanley	Chairman of the Board President and Chief Executive Officer	2/22/2017
/s/ Phillip S. Baker, Jr. Phillips S. Baker, Jr.	Director	2/22/2017
/s/ Julie A. Dill Julie A. Dill	Director	2/22/2017
/s/ Robert F. Heinemann Robert F. Heinemann	Director	2/22/2017
/s/ M. W. Scoggins M. W. Scoggins	Director	2/22/2017
/s/ David A. Trice David A. Trice	Director	2/22/2017
/s/ William L. Thacker, III William L. Thacker, III	Director	2/22/2017

Exhibit 31.1

CERTIFICATION

I, Charles B. Stanley, certify that:

1. I have reviewed this report of QEP Resources, Inc. on Form 10-K for the period ended December 31, 2016;

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

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

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

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

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

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

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

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

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

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

February 22, 2017

/s/ Charles B. Stanley

Charles B. Stanley

Chairman, President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Richard J. Doleshek, certify that:

1. I have reviewed this report of QEP Resources, Inc. on Form 10-K for the period ended December 31, 2016;

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

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

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

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

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

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

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

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

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

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

February 22, 2017

/s/ Richard J. Doleshek

Richard J. Doleshek

Executive Vice President and Chief Financial Officer

Exhibit 32.1

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

In connection with this report of QEP Resources, Inc. (the Company) on Form 10-K for the period ended December 31, 2016, as filed with the Securities and Exchange Commission on the date hereof (the Report), Charles B. Stanley, Chairman, President and Chief Executive Officer of the Company, and Richard J. Doleshek, Executive Vice President and Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

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

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

QEP RESOURCES, INC.

February 22, 2017

/s/ Charles B. Stanley
Charles B. Stanley
Chairman, President and Chief Executive Officer

February 22, 2017

/s/ Richard J. Doleshek
Richard J. Doleshek
Executive Vice President and Chief Financial Officer

Exhibit 99.1

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580
FAX (303) 623-4258
621 SEVENTEENTH STREET SUITE 1550 DENVER, COLORADO 80293 TELEPHONE (303) 623-9147

January 23, 2017

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

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of QEP Energy Company (QEP) as of December 31, 2016. The subject properties are located in the states of Colorado, Kansas, Louisiana, Montana, New Mexico, North Dakota, Oklahoma, Texas, Utah and Wyoming. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 23, 2017 and presented herein, was prepared for public disclosure by QEP in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of QEP as of December 31, 2016.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2016, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
QEP Energy Company
As of December 31, 2016

	Proved			
	Developed			
	Producing	Non-producing	Undeveloped	Total Proved
Net Remaining Reserves				
Oil/Condensate - Mbbl	101,344	1,806	135,431	238,581
Plant Products - Mbbl	33,700	1,995	31,467	67,162
Gas - MMcf	1,120,614	189,171	1,244,059	2,553,844
Income Data ($M)				
Future Gross Revenue	$ 6,559,616	$ 550,847	$ 8,291,881	$ 15,402,344
Deductions	3,861,443	361,175	6,161,763	10,384,381
Future Net Income (FNI)	$ 2,698,173	$ 189,672	$ 2,130,118	$ 5,017,963
Discounted FNI @ 10%	$ 1,768,932	$ 59,662	$ 528,491	$ 2,357,085

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

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

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion costs, development costs, and certain abandonment costs net of salvage. Other deductions are variable lease operating expenses. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist, nor does it include any adjustment for cash on hand or undistributed income. Future net income does not include depreciation, depletion and amortization affects nor any impairment conditions. Liquid hydrocarbon reserves account for approximately 62 percent and gas reserves account for the remaining 38 percent of total future gross revenue from proved reserves.

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

	Discounted Future Net Income ($M) As of December 31, 2016
Discount Rate Percent	Total Proved
5	$3,299,532
9	$2,508,317
15	$1,779,425
20	$1,397,434

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

Reserves Included in This Report

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

The various proved reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report. The proved developed non-producing reserves included herein consist of wells that are waiting on completion, behind pipe, shut-in, or temporarily abandoned.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist.

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

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward". The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

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

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

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

Estimates of Reserves

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

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

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

The proved reserves for the properties included herein were estimated by performance methods and analogy. All of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis which utilized extrapolations of historical production data available through December 2016 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by QEP and were considered sufficient for the purpose thereof.

Approximately 100 percent of the proved developed non-producing and undeveloped reserves included herein were estimated by analogy. The data utilized from the analogues were considered sufficient for the purpose thereof.

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

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

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

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by QEP. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

QEP furnished us with the above mentioned average prices in effect on December 31, 2016. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by QEP.

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

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
	Oil/Condensate	WTI Cushing	$42.75/bbl	$38.59/bbl
	NGLs	WTI Cushing	$42.75/bbl	$13.85/bbl
United States	Gas	Henry Hub	$2.48/MMBTU	$2.39/Mcf

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

Costs

Operating costs for the leases and wells in this report were furnished by QEP and are based on the operating expense reports of QEP and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells.

The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by QEP. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

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

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with QEP's plans to develop these reserves as of December 31, 2016. The implementation of QEP's development plans as presented to us and incorporated herein is subject to the approval process adopted by QEP's management. As the result of our inquiries during the course of preparing this report, QEP has informed us that the development activities included herein have been subjected to and received the internal approvals required by QEP's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to QEP. Additionally, QEP has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2016, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

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

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

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

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

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

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

Terms of Usage

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

QEP makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, QEP has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form

10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and/or S-8 of QEP of the references to our name as well as to the references to our third party report for QEP, which appears in the December 31, 2016 annual report on Form 10-K of QEP. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by QEP.

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

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

Very truly yours,

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

/s/James L. Baird
James L. Baird, P.E.
Colorado License No 41521
Managing Senior Vice President
[Seal]

/s/ Richard J. Marshall
Richard J. Marshall, P.E.
Colorado License No. 23260
Vice President
[Seal]

JLB-RJM (DPR)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Richard J. Marshall was the primary technical person responsible for overseeing the estimate of the future net reserves and income.

Marshall, an employee of Ryder Scott Company, L.P. (Ryder Scott) beginning in 1981, is a Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies. Before joining Ryder Scott, Marshall served in a number of engineering positions with Texaco, Phillips Petroleum, and others. For more information regarding Mr. Marshall's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Marshall earned a B.S. in Geology from the University of Missouri in 1974 and a M.S. in Geological Engineering from the University of Missouri at Rolla in 1976. Mr. Marshall is a registered Professional Engineer in the State of Colorado. He is a member of the Society of Petroleum Engineers, Wyoming Geological Association, Rocky Mountain Association of Geologists and the Society of Petroleum Evaluation Engineers.

Based on Mr. Marshall's educational background, professional training and more than 30 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Marshall has attained the professional qualifications as a Reserves Estimator and Reserves Auditor as set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.