QEP RESOURCES, INC.
Form 10-K
February 24, 2016

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

ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015
001-34778
(Commission File No.)

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

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

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

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

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ý No ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ¨ No ý
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically 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 ý 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 ý 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	ý		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 ý

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter (June 30, 2015): $3,270,110,187.

At January 31, 2016, there were 176,756,832 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 2016 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 http://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).

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;
- geographical diversity;
- our liquidity and sufficiency of cash flow from operations, cash-on-hand and availability under our credit facility to fund our planned capital expenditures, operating expenses, repayment of maturing debt and payment of dividends;
- ability to deliver growth by focusing on our exploration and production assets;
- our continued evaluation of, and ability to pursue, acquisition opportunities;
- our inventory of drilling locations;
- drilling and completion plans;
- focus on improving operating performance by optimizing reservoir development, enhancing well completion designs and aggressively pursuing cost reductions;
- results from planned drilling operations and production operations;
- plans to reduce drilling and completion activities, slow production growth and preserve liquidity;
- exports of oil from the U.S.;
- payment of dividends;

- estimates of reserves and development of proved undeveloped (PUD) reserves;
- leasehold development and financial capability to continue planned development;
- plans to recover or reject ethane from produced natural gas;
- impact of lower or higher commodity prices and interest rates;
- volatility of gas, oil 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;
- pro forma results for acquired properties;
- divestitures of non-core assets;
- any potential repurchases of our senior notes;

- amount and allocation of forecasted capital expenditures and plans for funding capital expenditures, operating expenses and development costs;
- resale revenues and expenses;
- adequacy of insurance;
- timing and impact of proposed environmental legislation and studies;
- impact of governmental 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 importance of Adjusted EBITDA (a non-GAAP financial measure) as a measure of performance;
- delays caused by transportation, processing, storage and refining capacity issues;
- fair values and critical accounting estimates, including estimated asset retirement obligations;
- uncertain tax 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;
- impact of the sale of our midstream business;
- the estimated costs of closing our Tulsa office;
- the impact of the loss of a significant customer or nonpayment of a counterparty;
- ability to meet delivery and sales commitments;
- value of pension plan assets;
- impact of our charter and bylaws on a potential takeover;
- inflation and deflation;
- unrecognized tax benefits;
- asset retirement obligations; and
- changes to production plans, operating costs and capital expenditures.

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 gas, oil 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 methods and results;
- shortages of oilfield equipment, services and personnel;
- lack of available pipeline, processing and refining capacity;
- our ability to successfully integrate acquired assets;
- 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 laws or regulations;
- legislation regarding climate change and other initiatives related to drilling and completion techniques, including hydraulic fracturing and water use;
- derivative activities;
- volatility in the commodity-futures market;
- failure of internal controls and procedures;
- failure of our information technology infrastructure or applications;
- 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 volumes;
- 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
- 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 non-cash and/or non-recurring items.

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-only swap A derivative that "swaps" the basis (defined above) between two sales points from a floating price to a fixed price for a specified commodity volume over a specified time period. A basis-only swap is typically used to fix the price relationship between a geographic sales point and a NYMEX reference price.

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.

developed reserves Reserves of any category that can be 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. See 17 C.F.R. Section 210.4-10(a)(6).

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. See 17 C.F.R. Section 210.4-10(a)(9).

dry hole A well drilled and abandoned and found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of production exceed expenses and taxes.

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. See 17 C.F.R. Section 210.4-10(a)(13).

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.

LIBOR London Interbank Offered Rate (LIBOR) is the interest rate that banks charge each other for one-month, three-month, six-month and one-year loans.

M Thousand.

MM Million.

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 6,000 cubic feet 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.

possible reserves Those additional reserves that are less certain to be recovered than probable reserves. See 17 C.F.R Section 210.4-10(a)(17).

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. See 17 C.F.R. Section 210.4-10(a)(18).

proved properties Properties with proved reserves. See 17 C.F.R. Section 210.4-10(a)(23).

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. See 17 C.F.R. Section 210.4-10(a)(22).

proved undeveloped reserves or PUD Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. See 17 C.F.R. Section 210.4-10(a)(31).

reserves Estimated remaining quantities of natural gas, crude oil 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. See 17 C.F.R. Section 210.4-10(a)(26).

reservoir A porous and permeable 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. See 17 C.F.R. Section 210.4-10(a)(27).

resource play Refers to regionally distributed oil and natural gas accumulation as opposed to conventional plays which are more limited in their 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 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.

T Trillion.

undeveloped reserves Reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. See 17 C.F.R. Section 210.4-10(a)(31).

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

FORM 10-K
ANNUAL REPORT 2015
PART I
ITEM 1. BUSINESS

Nature of Business

QEP Resources, Inc. (QEP or the Company) is a holding company with two principal subsidiaries, QEP Energy Company and QEP Marketing Company, which are engaged in two primary lines of business: (i) oil and gas exploration and production (QEP Energy) and (ii) oil and gas marketing, operation of a gas gathering system and an underground gas storage facility and corporate activities (QEP Marketing and Other). See Part II, Item 8 – Financial Statements and Supplementary Data, Note 14 – Operations by Line of Business, of the Notes to the Consolidated Financial Statements for financial information relating to our segments.

Effective January 1, 2016, QEP terminated its contracts for resale and marketing transactions between its wholly owned subsidiaries, QEP Marketing and QEP Energy. As a result, QEP Energy will market its own gas, oil and NGL production. In addition, substantially all of QEP Marketing's third-party purchase and sale agreements and gathering, processing and transportation contracts have been assigned to QEP Energy, except those contracts related to natural gas storage activities and the Haynesville gathering system (Haynesville Gathering). The change in affiliate transactions will simplify our business processes and financial statements by eliminating the majority of intercompany transactions.

QEP's operations are focused in two geographic regions: the Northern Region (primarily in Wyoming, North Dakota and Utah) and the Southern Region (primarily in Texas and Louisiana) of the United States. QEP's corporate headquarters are located in Denver, Colorado.

Discontinued Operations

On December 2, 2014, the Company closed the sale of 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). As a result of the Midstream Sale, the QEP Field Services Company (QEP Field Services) reporting segment, excluding the retained ownership of Haynesville Gathering, was classified as a discontinued operation on the Consolidated Statement of Operations and the Notes accompanying the Consolidated Financial Statements. For reporting purposes, Haynesville Gathering has been added to the QEP Marketing and Other segment.

Financial and Operating Highlights

Our financial and operating highlights for 2015 are as follows:
- Achieved record equivalent production of 326.8 Bcfe, a 1% increase over 2014;
- Increased oil production to 19.6 MMbbls, a 14% increase over 2014, including 76% growth in the Permian Basin and 13% growth in the Williston Basin;
- Increased natural gas production to 181.1 Bcf, including record production in Pinedale;
- Generated a net loss of $149.4 million, or $0.85 per diluted share;
- Generated $1,029.3 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), of which $1,027.1 million was contributed by QEP Energy;
- Incurred capital expenditures (excluding property acquisitions) of $1,011.9 million, a 41% reduction from 2014;
- Reduced general and administrative expenses by $23.3 million, or 11%;

- Received field-level prices that were 42% lower than in 2014, however, our commodity derivative contracts offset 19% of this decrease; and
- Maintained $376.1 million in cash and cash equivalents and had no borrowings under our revolving credit facility.

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;
- acquire businesses and assets that complement or expand our current business;

- maintain a sustainable, diverse inventory of low-cost, high-margin 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 mitigate the impact of gas, oil or NGL price volatility and to lock in acceptable cash flows required to support future capital expenditures;
- attract and retain the best people; and
- maintain a capital structure that provides us the necessary financial flexibility with which to invest in organic growth and potential acquisition opportunities, as they may arise.

In response to the current commodity price environment, we have reduced drilling and completion activities, slowed production growth, reduced costs and preserved our liquidity. We plan to continue these strategies in 2016. We have reduced the number of QEP operated drilling rigs to nine as of December 31, 2015, compared to a high of 21 during 2014. We have reduced our annual capital expenditure budget (excluding property acquisitions) significantly for 2016 to approximately $475.0 million from approximately $1.0 billion in 2015. We are focused on driving improved operating performance by optimizing reservoir development, enhancing well completion designs and aggressively pursuing cost reductions.

On December 2, 2014, QEP completed the Midstream Sale; see "Discontinued Operations" above. QEP believes this transaction represented a significant milestone in the strategic repositioning of the Company, as it has better positioned the Company to focus on its exploration and production assets.

Exploration and Production – QEP Energy

QEP Energy conducts exploration and production (E&P) activities in several of North America's most important hydrocarbon resource plays. QEP Energy has an inventory of identified development drilling locations in the Pinedale Anticline in western Wyoming, the Williston Basin in North Dakota, the Uinta Basin in eastern Utah, the Permian Basin in western Texas, the Haynesville/Cotton Valley in northwestern Louisiana, and other proven properties in Wyoming, Utah and Colorado. In recent years, QEP sold substantially all of its properties within its Midcontinent area in the Southern Region, which is located in the Anadarko Basin in Oklahoma and Texas.

On February 25, 2014, QEP Energy acquired oil and gas properties in the Permian Basin of Texas 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. The Permian Basin Acquisition created a new core area of operations for QEP Energy.

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, 2015:

QEP Energy generated approximately $1,027.1 million, $1,437.0 million, and $1,301.8 million of the Company's Adjusted EBITDA from continuing operations during the years ended December 31, 2015, 2014 and 2013, respectively (refer to Item 7 of Part II of this Annual Report on Form 10-K for management's definition and a reconciliation to net income of this non-GAAP financial measure). During 2015, QEP Energy operated in two regions – the Northern Region (including the states of Wyoming, North Dakota, Utah and Colorado) and the Southern Region (including the states of Texas and Louisiana). The Northern Region contributed 78% of 2015 production, while the Southern Region contributed 22%. QEP Energy reported 3,620.2 Bcfe of estimated proved reserves as of December 31, 2015, down 311.7 Bcfe from 2014. Of those estimated proved reserves, approximately 79%, or 2,844.0 Bcfe, were located in the Northern Region at December 31, 2015, compared to 77%, or 3,026.0 Bcfe, at December 31, 2014. The remaining 21%, or 776.2 Bcfe, were located in the Southern Region at December 31, 2015, compared to 23%, or 905.9 Bcfe, at December 31, 2014. Approximately 58% of the total proved reserves reported by QEP Energy at December 31, 2015, were developed and approximately 42% of the total proved reserves were comprised of oil and NGL, up from 41% at December 31, 2014.

QEP Energy faces competition in every facet of its business, including the acquisition of producing leaseholds, wells and undeveloped leaseholds, the marketing of oil and gas, and the procurement of goods, services and labor. Its longer-term growth strategy depends, in part, on its ability to acquire reasonably valued acreage containing undeveloped reserves and identify and develop the reserves in a responsible, low-cost and efficient manner.

QEP Energy 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 many wells at high density to fully develop and recover the hydrocarbon accumulations. QEP Energy's resource play development requires expertise in drilling a large number of complex, highly deviated or horizontal wells to true vertical depths, which generally range between 10,000 and 14,000 feet, and the application of advanced well completion techniques, including hydraulic fracture stimulation, to achieve economic production rates and recoverable volumes. QEP Energy also conducts exploratory drilling to determine the commercial viability of its unproven leasehold inventory. For 2016, QEP plans to allocate approximately $475.0 million of its capital budget to E&P activities. QEP Energy 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 Energy sells its gas, oil and NGL production to a variety of customers, including gas-marketing firms, industrial users, local-distribution companies, crude oil refiners and marketers. QEP Energy regularly evaluates counterparty credit risk and may require financial guarantees or prepayments from parties that fail to meet its credit criteria.

Energy Marketing — QEP Marketing and Other

QEP Marketing provides wholesale marketing and sales of affiliate and third-party gas, oil and NGL. The reporting segment QEP Marketing and Other generated $2.2 million, $1.3 million and $14.2 million of the Company's Adjusted EBITDA from continuing operations (refer to Item 7 of Part II of this Annual Report on Form 10-K for management's definition and a reconciliation to net income of this non-GAAP financial measure) for each of the years ended December 31, 2015, 2014 and 2013, respectively. As a wholesale marketing entity, QEP Marketing concentrates on markets in the Rocky Mountains and Haynesville that are either close to affiliate reserves and production or accessible by major pipelines. QEP Marketing contracts for firm-transportation capacity on pipelines and firm-storage capacity at Clay Basin, a large gas storage facility in northeast Utah.

QEP Marketing, through its wholly owned subsidiary Clear Creek Storage Company, LLC (Clear Creek), owns and operates an underground gas storage reservoir in southwestern Wyoming. QEP Marketing uses owned and leased storage capacity together with firm-transportation capacity to manage seasonal swings in prices in the Rocky Mountain region. QEP Marketing also sells NGL volumes associated with the gas stored in its Clear Creek storage facility. In addition, QEP Marketing owns a membership interest in Haynesville Gathering, located in Louisiana. Haynesville Gathering includes 200 miles of gas gathering facilities with approximate throughput capacity of 2,000 MMcf/d and a treating facility with throughput capacity of 600 MMcf/d and primarily provides services to QEP Energy.

QEP Marketing competes directly with large independent energy marketers, marketing affiliates of regulated pipelines and utilities and natural gas producers. QEP Marketing also competes with brokerage houses, energy hedge funds and other energy-based companies offering similar services. QEP Marketing sells gas volumes to wholesale marketers, industrial users and utilities. QEP Marketing sells oil volumes to refiners, marketers and other companies, including some with pipeline facilities near QEP Energy's producing properties. In the event pipeline facilities are not available, QEP Marketing arranges transportation of oil by truck or rail to storage, refining or pipeline facilities.

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. While QEP believes that it is in compliance, in all material respects, with currently applicable laws and regulations and has not experienced any material adverse effect arising from these requirements, there is no assurance that this trend will continue in the future. Due to the myriad of complex federal, state, tribal and local regulations that may affect QEP, directly or indirectly, 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 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 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. The Environmental Protection Agency (EPA) has adopted or proposed to adopt various regulations governing air quality standards and controls, source determination and permitting requirements, and methane emissions. The EPA is considering adopting more stringent air permitting and other air quality regulations specific to oil and gas exploration, production, gathering and processing that go beyond the requirements of existing federal regulations.

Additionally, many states have adopted, or are considering 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 Gases Regulations and Climate Change Legislation. In December 2009, the EPA published its findings that emissions of carbon dioxide, methane, and other greenhouse gases (GHG) endanger public health and the environment because such emissions are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. Based on these findings, the EPA has adopted and substantially expanded regulations for the measurement and annual reporting of 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 in recent years 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 regional GHG cap and trade programs.

Bureau of Land Management Methane Regulations. In January 2016, the Department of Interior's Bureau of Land Management (BLM) announced a proposed rule dealing with venting and flaring of oil and natural gas, leak detection, storage tanks, pneumatic controllers and pumps, well maintenance and unloading, drilling and completions, and royalties for oil and gas facilities producing on federal and tribal lands. The proposed rule was published in the Federal Register in February 2016. QEP is evaluating the economic implications of complying with this rule, but the rule could potentially lead to QEP plugging and abandoning some of its existing oil and gas wells on federal and tribal lands and the loss of certain unproduced oil and gas reserves.

Clean Water Act and Safe Drinking Water Act. The 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 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.

In May 2015, the EPA and the Army Corps of Engineers issued a pre-publication final rule defining the 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 jurisdiction under the Clean Water Act.

Oil Pollution Act of 1990. The 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 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. A person responsible for releases of hazardous substances under CERCLA 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. Frequently, third parties file claims for personal injury and property damage allegedly caused by the hazardous substances into the environment.

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 on 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." It is possible, however, that certain exploration and production wastes now classified as non-hazardous could be classified as hazardous waste in the future. 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.

Hydraulic Fracturing Regulations. All wells drilled in tight sand or shale reservoirs require hydraulic fracture stimulation to achieve economic production rates and recoverable reserves. The majority of 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 does not use diesel fuel in any of its fracturing operations. 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 possible 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 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 potential regulations to address the effects of hydraulic fracturing on drinking water. Additionally, in March 2015, the BLM finalized new regulations, 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 land. The new 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 lands. Several states, including some in which QEP operates, have filed suit against the Department of Interior over the final BLM hydraulic fracturing regulations, and as a result the effective date of the regulations has been indefinitely stayed pending the outcome of the litigation.

Legislation has also been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process, notwithstanding the proposed and ongoing rulemaking proceedings and voluntary disclosures to FracFocus noted above. 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 where QEP Energy operates. These regulations include, but are not limited to, such matters as lease provisions, drilling and production requirements, surface use restrictions, environmental standards and royalty considerations. Recently, the BIA published final regulations (effective in March 2016) significantly altering 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 operation on tribal lands.

Endangered Species Act, National Environmental Policy Act. 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. Many of QEP's operations are subject to the requirements of the National Environmental Policy Act (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 the Council on Environmental Quality and other agency regulations, usually for the BLM in the areas where QEP operates.

Emergency Planning and Community Right-to-Know Act and Occupational Safety and Health Act. The Emergency Planning and Community Right-to-Know Act (EPCRA) requires certain facilities to disseminate information on chemical inventories to employees as well as local emergency planning committees and emergency response departments. In October 2015, the EPA indicated its intent to commence a rulemaking to add natural gas processing facilities to the list of facilities that must report under EPCRA; however, it also declined to extend EPCRA to cover other types of facilities in the oil and gas sector. 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 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, 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.

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 addition, 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. Based on its production forecasts and midstream agreements, QEP believes it is and will continue to be in compliance with this order from the Commission.

On December 9, 2014, the Commission issued Commission Order No. 25417 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 Commission's order was effective April 1, 2015. QEP believes it is currently in compliance with this new order from the Commission.

Other Regulations

Transporting Crude Oil by Rail. The U.S. Department of Transportation has started rulemaking to develop new requirements for shipping crude oil by rail. 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.

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.

Seasonality

QEP drills and completes wells throughout the year, but adverse weather conditions can impact drilling and field operations. In the Pinedale field, QEP typically ceases completion activities on newly drilled wells due to adverse weather conditions in the fourth quarter and resumes completion activity in the first quarter as weather allows.

Significant Customers

QEP's five largest customers accounted for 30%, 33%, and 38%, in the aggregate, of QEP's revenues for the years ended December 31, 2015, 2014 and 2013, respectively. 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. 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 and Supply Company accounted for 10% of the Company's total revenues. During the year ended December 31, 2013, Freepoint Commodities, LLC accounted for 13% of the Company's total revenues.

Employees

At December 31, 2015, QEP had 693 employees compared to 765 employees at December 31, 2014. 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, 2016, are listed below:

Charles B. Stanley	57	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	57	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, Hilcorp Energy Company (2001 to 2009).
Jim E. Torgerson	52	Executive Vice President (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).
Austin S. Murr	62	Senior Vice President - Business Development (2012 to present). Vice President - Land and Business Development (2010 - 2012). Previous titles with Questar Corporation: Vice President - Land and Business Development (2006 - 2010); Director of Business Development (2004 to 2006).
Christopher K. Woosley	46	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	52	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	43	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	42	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.

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

- changes in domestic and foreign supply and demand of gas, oil and NGL;
- the potential long-term impact of an abundance of gas, oil and NGL from unconventional sources on the global and local energy supply;
- changes in local, regional, national and global demand for gas, oil, NGL and related commodities;

- the level of imports and/or exports of, and the price of, foreign gas, oil 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 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), including the ability of members of OPEC to agree to and maintain oil price and production controls and the ability of Iran to market its oil following the lifting of trade sanctions;
- 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;
- weather conditions and natural disasters;
- government regulations and taxes, including regulations or legislation relating to climate change 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 as well as natural gas used as fuel for electricity generation;
- the level of global gas, oil and NGL inventories and exploration and production activity; and
- the quality of oil and gas produced.

QEP's revenues, operating income and future rate of growth depend heavily on the prices QEP receives for the crude oil and natural gas it produces and sells. Prices also affect the amount of cash QEP has available for capital expenditures, its ability to repay debt, borrow money or raise additional capital, the amount and value of its proved reserves and the price of QEP's common stock. In response to lower commodity prices, QEP reduced its 2015 capital expenditures by approximately 59% in 2015 and plans to reduce its 2016 capital expenditures as compared to 2015 by over 50%. In 2015, QEP also reduced drilling and completion activities, slowed production growth, reduced costs and preserved its liquidity. QEP plans to continue these strategies in 2016. In February 2016, in response to the current commodity price environment, the Board of Directors indefinitely suspended the payment of quarterly dividends. If market prices for gas, oil and NGL continue to decline, QEP may elect to curtail production, further reduce operation costs and capital expenditures and discontinue certain exploration and development programs. QEP may be unable to decrease its costs in an amount sufficient to offset reductions in revenues from lower commodity prices and may incur losses.

Lower gas, oil and NGL prices or negative adjustments to gas, oil and NGL reserves may result in significant impairment charges. Lower commodity prices, such as those experienced recently, may not only decrease QEP's revenues, operating income and cash flows but also may reduce the amount of gas, oil 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, 2015, 2014 and 2013, QEP recorded impairment charges of $39.3 million, $1,041.4 million and $1.2 million, respectively, on its proved properties and $2.0 million, $101.8 million and $32.3 million, respectively, on its unproved properties. QEP also recorded goodwill impairment of $14.3 million and $59.5 million during the years ended December 31, 2015 and December 31, 2013, respectively. Forward prices in mid February 2016 have declined subsequent to the test for impairment at December 31, 2015. If forward prices remain at mid February 2016 levels, we have approximately $1.8

billion of proved property net book value, as of December 31, 2015, primarily associated with our Pinedale field, at risk for impairment. The actual amount of impairment incurred, if any, for these properties will depend on a variety of factors including, but not limited to, subsequent forward price curve changes, the additional risk-adjusted value of probable and possible reserves associated with the properties, weighted-average cost of capital, operating cost estimates and future capital expenditure estimates. Additionally, a further decrease from mid February levels in forward gas, oil or NGL prices could result in additional properties being at risk for impairment. If QEP records a significant impairment, the financial covenants under its revolving credit facility may limit the amount of debt that QEP is able to incur. See Part I, Item 8, Note 1 – Summary of Significant Accounting Policies, of this Annual Report on Form 10-K for additional information.

Slower U.S. and global economic growth rates may continue to materially adversely impact QEP's operating results. The U.S. and other economies are still recovering from the global financial crisis of 2008 and the recession that followed. Growth has been modest and at an unsteady rate. More volatility may occur before a sustainable growth rate is achieved. Historically, global economic growth drives demand for energy from all sources, including fossil fuels. If future economic growth rates, particularly in China, the U.S. and Europe, are lower, excluding changes in other factors, demand for QEP's gas, oil and NGL production will likely decrease, resulting in further decreases in commodity prices and reductions to QEP's revenues, cash flows from operations and its profitability.

The Company may not be able to economically find and develop new reserves. The Company's profitability depends not only on prevailing prices for gas, oil 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 properties, 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 percent 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.

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, and increasing prices for, oilfield equipment, services and qualified personnel could impact results of operations. Although it is not currently an issue, if the prices of oil and gas increase, 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, can increase accordingly, creating challenges and causing periodic shortages. In periods of high prices, there have also been regional shortages of drilling rigs and other equipment. Any cost increases associated with a recovery of prices 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 gas, oil and NGL, including:

- injuries and/or deaths of employees, supplier personnel, or other individuals;
- fire, explosions and blowouts;

- 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, cyberattacks, 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; 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 and 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 the operator and 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 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 for property damage suffered by the contractor.

As is also customary in the oil and gas industry, QEP maintains insurance against some, but not all, of these potential risks and losses. 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.

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:

- 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 results are less than anticipated, the return on our investment for a particular project may not be as attractive as we anticipated, we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

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 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 gas, oil and NGL gathering and transportation, including trucks, railways and pipelines, gas processing, storage or refining capacity may hinder QEP's access to gas, oil 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. If transportation quality requirements change, 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 booked 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 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 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.

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, 2015, QEP’s aggregate long-term contractual obligation under these agreements was $807.7 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 gas, oil 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 has no borrowings under its revolving 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 EBITDAX (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 its results of operations.

QEP's debt and other financial commitments may limit its financial and operating flexibility. QEP's total debt was approximately $2.2 billion at December 31, 2015. 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 the current commodity price environment continues and QEP continues to reduce 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 revolving credit agreement in the future. Refer to 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. On February 10, 2016, Standard & Poor’s Financial Services LLC (S&P) reaffirmed QEP’s credit rating of BB+ but changed its outlook from stable to negative. On February 12, 2016, Moody’s Investor Services, Inc. (Moody’s) downgraded QEP’s credit rating from Ba1 to B1. QEP's credit ratings may be subject to future downgrades. The downgrade by Moody’s triggered an additional financial covenant under QEP’s credit agreement, which could limit the amount of debt that QEP may incur. The downgrade of its credit rating may make it more difficult or expensive for QEP to raise capital from financial institutions or other sources. In addition, a further downgrade could require QEP to provide financial assurance of its performance under certain contractual arrangements and derivative agreements.

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, 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 gas, oil 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 gas, oil 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. 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, which are heightened in periods of low commodity prices, 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 financial guarantees 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 non-governmental organizations 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, 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;
- cyberattacks;
- legal challenges or lawsuits;
- negative publicity about QEP;
- 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 and 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 gas, oil 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 business.

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 Permian Basin Acquisition completed in February 2014. 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 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 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 agreements 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 agreements also limit QEP’s ability to incur certain indebtedness, which could indirectly limit QEP’s ability to engage in acquisitions of businesses.

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 can materially affect QEP's ability to dispose of assets on terms acceptable to QEP. Such factors include current commodity prices, laws, regulations and the permitting process impacting oil and gas operations in the areas where the assets are located, 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, QEP is involved in various legal proceedings, such as title, royalty, and contractual disputes, in the ordinary course of its business. The cost to settle legal proceedings or satisfy any resulting judgment against QEP in such proceedings could result in a substantial liability, which could materially and adversely impact QEP's cash flows and operating results for a particular period. Current accruals for such liabilities may be insufficient. 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.

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.

For example, in May 2015, the EPA and the Army Corps of Engineers issued a pre-publication final rule defining the 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 increase the scope of waters subject to federal jurisdiction under the Clean Water Act.

Also, new 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 and is undergoing further reconsideration by the EPA, which may result in more stringent air quality controls and requirements for QEP’s operations. For example, in September 2015, the EPA published proposed updates to Subpart OOOO to achieve additional methane and volatile organic compound reductions from certain activities in the oil and gas industry. The proposed rule would include, among others, new requirements for finding and repairing leaks at new well sites and reduced emission completion requirements for 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 October 2015, the EPA announced its final ruling to lower the existing 75 parts per billion (ppb) National Ambient Air Quality Standard (NAAQS) for ozone under the federal Clean Air Act to 70 ppb. A lowered ozone NAAQS could result in a significant expansion of ozone nonattainment across the United States, including areas in which QEP operates. Oil and natural gas operation in ozone nonattainment areas would likely be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs.

In September 2015, the EPA published a proposed rule under the Clean Air Act regarding source determination and permitting requirements for the onshore oil and gas industry. The proposed rule seeks public comment on two approaches for defining the term "adjacent", which is one of three factors used to determine whether oil and gas equipment and activities at multiple locations may be considered part of a single source that is subject to permitting requirements under the Clean Air Act. Depending on the EPA's final approach, the oil and gas industry could be subject to increased air quality permitting costs and more stringent control requirements and enhanced reporting requirements and costs.

In September 2015, the EPA also issued a proposed FIP to implement the Federal Minor New Source Review Program in Indian Country for oil and gas production. The proposed FIP may apply to 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 proposed FIP would incorporate emission limits and other requirements for various federal air quality standards, applying them to a range of equipment and processes used in oil and gas production. The FIP may also lead to the EPA imposing reservation-specific regulations on the Uintah and Ouray Indian reservations in Utah, requiring controls on existing equipment in the area due to ozone readings above the NAAQS standard in several previous years. The proposals will likely have increased controls and compliance costs.

The FERC has jurisdiction over the operation of QEP Marketing'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, 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. The BLM has proposed a new rule related to further controls on the venting and flaring of natural gas on BLM land. The proposed rule has been finalized and is out for public comment. These 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 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 in areas where we operate as threatened or endangered 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 on the Pinedale Anticline 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 and legislation introduced in a prior session of Congress includes 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 Clean Air Act, the Clean Water Act, the 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 environmental groups to oppose drilling on some of QEP's federal and state leases. These groups 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 recently published final regulations (effective in March 2016) significantly altering 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 recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the SDWA and issued guidance related to this newly 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, in May 2012, the BLM proposed new regulations regarding chemical disclosure requirements and other regulations specific to well stimulation activities, including hydraulic fracturing, on federal and tribal lands and proposed further revision to those regulations in May 2013. The BLM finalized those regulations in March 2015, to become effective in June 2015; however, due to pending litigation (discussed below), the effective date of the rule has been postponed. The new 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 lands. Several states, including some in which the Company operates, have filed suit against the Department of Interior over the final BLM hydraulic fracturing regulations, which could contribute to increased uncertainty regarding the Company’s compliance obligations on federal and tribal lands and has caused the effective date of the regulations to be postponed.

Legislation has also been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process, notwithstanding the proposed and ongoing rulemaking proceedings noted above. 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 is also considering other potential regulation of hydraulic fracturing activities. For example, in April 2015, the EPA published proposed pretreatment standards for the oil and gas extraction industry. The proposed regulations would address discharges of wastewater pollutants from onshore unconventional oil and gas extraction facilities to publicly owned treatment works. The EPA is also collecting information as part of a nationwide study into the effects of hydraulic fracturing on drinking water. In June 2015, the EPA released a draft assessment of the potential impacts to drinking water resources from hydraulic fracturing for public comment and peer review. The results of this study, which has not been finalized, 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 (TSCA) 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 2015, several national environmental advocacy groups filed a lawsuit requesting that the EPA add the oil and gas extraction industry to the list of industries required to report releases of certain "toxic chemicals" under the Toxics Release Inventory (TRI) program of the Emergency Planning and Community Right-to-Know Act. The EPA responded to the groups’ request in October 2015 granting the petition in part as it related to natural gas processing facilities, and denying the petition as to all other types of facilities in the oil and gas sector.

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. In addition, concerns have been raised about the potential for induced seismicity from the use of underground injection wells, a predominant method for disposing of waste water (including hydraulic fracturing flowback water) from oil and gas activities. QEP operates injection wells and utilizes injection wells owned by third parties to dispose of waste water associated with its operations. New rules and regulations may be developed to address these concerns, possibly limiting or eliminating the ability to use disposal wells in certain locations and increasing the cost of disposal in others. Further, lawsuits against other companies have been filed by plaintiffs alleging they suffered damages from seismicity caused by injection of waste water into disposal wells, which may make it more expensive or difficult to conduct water disposal activities and to obtain insurance for such activities.

The adoption of greenhouse gas (GHG) emission or other environmental legislation could result in increased operating costs, delays in obtaining air pollution permits for new or modified facilities, and reduced demand for the gas, oil 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 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. Legislative bills have been proposed in Congress that would regulate GHG emissions through a cap-and-trade system under which emitters would be required to buy allowances for offsets of emissions of GHG. The EPA has adopted final regulations for the measurement and reporting of GHG emitted from certain large facilities and, as discussed above, has proposed additional regulations at 40 C.F.R Part 60, Subpart OOOO 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 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. It is uncertain whether QEP's operations and properties, located in the Northern and Southern Regions of the United States, are exposed to possible physical risks, such as severe weather patterns, due to climate change, whether or not climate change is caused by anthropogenic emissions of GHG. Management does not, however, believe such physical risks are reasonably likely to have a material effect on the Company's financial condition or results of operations. In December 2015, over 190 countries, including the U.S., reached an agreement to reduce global emissions of GHG. To the extent the U.S. and other countries implement this agreement or impose other climate change regulations on the oil and gas industry, it could have an adverse direct or indirect effect on our business.

The adoption and implementation of new statutory and regulatory requirements for swap transactions could have an adverse impact on QEP's ability to mitigate risks associated with its business and increase the working capital requirements to conduct these activities. 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 Act provides for an exception from these clearing requirements for commercial end-users, such as QEP. The Dodd-Frank Act may, however, require the posting of cash collateral for uncleared swaps and may limit trading in certain oil and gas related derivative contracts by imposing position limits. 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.

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.

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 results. QEP's 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 50 active and suspended participants, or 7%, of QEP's active employees and 164 participants who are retired or were terminated and vested. Effective January 1, 2016, the Pension Plan was frozen, such that employees do not earn additional defined benefits for future services. QEP also sponsors an unfunded, nonqualified Supplemental Executive Retirement Plan (SERP). Over time, periods of declines in interest rates and pension asset values may result in a reduction in the funded status of the Company's pension plans. As of December 31, 2015 and 2014, QEP's pension plans were underfunded by $41.0 million and $51.2 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 $7.5 million and $13.0 million during the years ended December 31, 2015 and 2014, respectively, to the Pension Plan and SERP and expects to make contributions of approximately $6.9 million to these pension plans in 2016. QEP cannot, however, predict whether changing economic conditions, the future performance of assets in the plans or other factors will require the Company to make contributions in excess of its current expectations, diverting funds QEP would otherwise apply to other uses.

QEP is exposed to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption and/or financial loss. The oil and gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, and processing activities. For example, QEP depends on digital technologies to interpret seismic data, manage drilling rigs, production equipment and gathering systems, conduct reservoir modeling and reserves estimation, and process and record financial and operating data. Pipelines, refineries, power stations and distribution points for both fuels and electricity are becoming more interconnected by computer systems. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. QEP's technologies, systems, networks, and those of its vendors, suppliers and other business partners may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of its business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. QEP'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.

QEP's certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, even if such 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 of provisions 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Exploration and Production – QEP Energy

QEP's exploration and production business is conducted through QEP Energy in two regions - the Northern Region (including the states of Wyoming, North Dakota, Utah and Colorado) and the Southern Region (including the states of Texas and Louisiana).

Northern Region

Pinedale
QEP Energy's largest property, in terms of proved reserves, is Pinedale, where the Company is actively developing the Lance Pool, which is a tight gas sand reservoir. The depth to the top of the Lance Pool reservoir ranges from 8,500 to 9,500 feet across QEP Energy's leasehold. The Company currently estimates that there are up to approximately 250 additional wells required to fully develop its Pinedale acreage on 5 to 10-acre density. On December 31, 2015, QEP Energy had three operated rigs drilling on the Pinedale Anticline. The Company has been successful in reducing development well costs and increasing production at Pinedale. Included in QEP Energy's 1,071 gross producing wells at Pinedale are 69 wells in which QEP Energy has a small overriding royalty interest.

Williston Basin
QEP Energy is actively developing the Bakken and Three Forks formations in the Williston Basin. The depth to the top of the Bakken Formation ranges from approximately 9,500 feet to 10,000 feet across QEP Energy's leasehold. Multiple benches of the Three Forks formation are approximately 60 to 70 feet below the Middle Bakken formation and are also targets for horizontal drilling. The Company has been successful in reducing development well costs, de-risking unproven reserves, increasing production, increasing the number of future drilling locations and increasing its estimate of recoverable reserves. As of December 31, 2015, QEP Energy had three operated rigs drilling in the Williston Basin.

Uinta Basin
The majority of the Uinta Basin's proved reserves are found in a series of vertically stacked, laterally discontinuous reservoirs at depths of 4,500 feet to deeper than 17,000 feet. QEP Energy had one operated rig drilling in the Uinta Basin at December 31, 2015, targeting the Lower Mesaverde Formation in which QEP Energy holds acreage in the Red Wash Unit and South Red Wash Unit.

Other Northern
The remainder of QEP Energy's Northern Region leasehold interests and proved reserves are distributed over a number of fields and properties.

Southern Region

Permian Basin
QEP Energy is developing oil producing zones in the Wolfcamp and Spraberry formations to vertical depths of 10,000 to 12,000 feet in the Permian Basin. In 2015, QEP transitioned to exclusively drilling horizontal wells. The Company has been successful in reducing development well costs and increasing production. As of December 31, 2015, QEP Energy had two operated rigs drilling in the Permian Basin.

Haynesville/Cotton Valley
QEP Energy holds producing and undeveloped properties in the Haynesville Shale play in northwestern Louisiana and additional lease rights that cover the Hosston and Cotton Valley formations. The top of the Haynesville Shale ranges

from approximately 10,500 feet to 12,500 feet across QEP Energy's leasehold and is deeper than the Hosston and Cotton Valley formations that QEP Energy has been developing in northwest Louisiana since the 1990's. As of December 31, 2015, QEP Energy did not have any operated rigs drilling in the Haynesville/Cotton Valley area, however, there were six gross non-operated wells waiting on completion as of December 31, 2015.

Midcontinent

QEP Energy's Midcontinent operations cover all properties in the Southern Region except the Haynesville/Cotton Valley area of northwestern Louisiana and the Permian Basin properties in west Texas and are widely distributed. QEP sold the majority of its Midcontinent properties in 2014, including its properties in the Woodford "Cana" Shale in western Oklahoma, Granite Wash/Atoka Wash in the Texas panhandle and western Oklahoma and has continued to divest other non-core properties within this area throughout 2015. As of December 31, 2015, QEP Energy did not have any operated rigs drilling in the Midcontinent area.

Reserves – QEP Energy

At December 31, 2015 and 2014, QEP Energy's estimated proved reserves were approximately 3,620.2 Bcfe and 3,931.9 Bcfe, respectively, of which 96% and 93%, respectively, were Company operated. Proved developed reserves represented 58% and 56% of the Company's total proved reserves at December 31, 2015 and 2014, respectively, while the remaining reserves were classified as proved undeveloped. All reported reserves are located in the United States. QEP Energy 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 Energy's estimated proved reserves are summarized in the table below:

	December 31, 2015				December 31, 2014			
	Gas (Bcf)	Oil (MMbbl)	NGL (MMbbl)	Total (Bcfe)[1]	Gas (Bcf)	Oil (MMbbl)	NGL (MMbbl)	Total (Bcfe)[1]
Proved developed reserves	1,245.3	109.7	34.4	2,109.4	1,288.4	99.3	52.2	2,197.5
Proved undeveloped reserves	863.6	83.4	24.4	1,510.8	1,028.8	73.2	44.4	1,734.4
Total proved reserves	2,108.9	193.1	58.8	3,620.2	2,317.2	172.5	96.6	3,931.9

(1) Oil and NGL are converted to natural gas equivalents at the ratio of one barrel of crude oil, condensate or NGL to six Mcf of equivalent natural gas.

QEP Energy's reserve, production and production life index for each of the years ended December 31, 2013, through December 31, 2015, are summarized in the table below:

Year Ended December 31,	Year End Reserves (Bcfe)	Gas, Oil and NGL Production (Bcfe)	Reserve Life Index [1] (Years)
2013	4,061.9	309.0	13.1
2014	3,931.9	322.7	12.2
2015	3,620.2	326.8	11.1

(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 expand 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 16 – 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 Energy's proved reserves in major operating areas are summarized in the table below:

	December 31,			
	2015		2014	
Northern Region	(Bcfe)	(% of total)	(Bcfe)	(% of total)
Pinedale	1,125.0	31 %	1,450.1	37 %
Williston Basin	1,085.7	30 %	858.9	22 %
Uinta Basin	558.9	16 %	623.0	16 %
Other Northern	74.4	2 %	94.0	2 %
Southern Region				
Haynesville/Cotton Valley	396.5	11 %	493.9	13 %
Permian Basin	374.0	10 %	375.7	10 %
Midcontinent	5.7	— %	36.3	— %
Total QEP Energy	3,620.2	100 %	3,931.9	100 %

Estimates of the quantity of proved reserves decreased during 2015 primarily due to lower gas, oil, and NGL prices. Other factors impacting this decrease include operating in ethane rejection in Pinedale and in the Uinta Basin, as well as decreases in estimated proved reserves in Pinedale and Haynesville/Cotton Valley as a result of fewer PUD locations. These proved reserve decreases were partially offset by extensions and additions in the Williston, Uinta, and Permian basins from the recognition of additional PUD locations due to the increased drilling program.

Proved Undeveloped Reserves

Significant changes to PUD reserves that occurred during 2015 are summarized in the table below:

	2015
	(Bcfe)
Proved undeveloped reserves at January 1,	1,734.4
Transferred to proved developed reserves	(397.5)
Revisions to previous estimates[(1)]	(778.9)
Extensions and discoveries[(2)]	945.4
Purchase of reserves in place[(3)]	7.4
Proved undeveloped reserves at December 31,[(4)]	1,510.8

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(1) Revisions of previous estimates in 2015 include: 514.2 Bcfe of negative revisions due to lower pricing and 303.7 Bcfe of negative revisions unrelated to pricing, partially offset by 39.0 Bcfe of positive performance revisions. Negative pricing revisions were driven by lower gas, oil and NGL prices. Negative other revisions were primarily the result of slowing the pace of planned drilling activity and operating in ethane rejection in Pinedale and the Uinta Basin.

(2) The increase in reserves due to extensions and discoveries in 2015 was comprised of 325.8 Bcfe in the Williston Basin, 300.6 Bcfe in the Uinta Basin, 242.1 Bcfe in the Permian Basin, 45.9 Bcfe in Pinedale, and 31.0 Bcfe in Haynesville/Cotton Valley. Extensions and discoveries relate to new PUD locations driven by drilling activity in 2015, as well as new compression projections in Pinedale.

(3) Purchase of reserves in place in 2015 related to the acquisition of additional interests in QEP's operated wells in the Williston Basin as discussed in Note 2 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K.

(4) All of QEP Energy's PUD reserves at December 31, 2015, are scheduled to be developed within five years from the date such locations were initially disclosed as PUD reserves; however, long-term development of gas reserves in Pinedale is governed by the BLM's September 2008 ROD on the FSEIS. Under the ROD, QEP Energy is allowed to drill and complete wells year-round in designated concentrated development areas. The ROD contains additional requirements and restrictions on the sequence of development, which requires the Company to develop its leasehold from the south to the north. These restrictions result in protracted, phased development that is beyond the

control of the Company. The Company has an ongoing development plan and the financial capability to continue development in the manner estimated. Additionally, QEP Energy plans to develop its PUD reserves prior to lease expiration or extend the term of the lease.

The costs incurred to continue the development of PUD reserves were approximately $811.3 million, $796.7 million, and $645.9 million for the years ended December 31, 2015, 2014 and 2013, respectively. The costs incurred in 2015 related to the drilling of PUD locations in QEP's operating areas. This investment resulted in the transfer of 397.5 Bcfe of PUD reserves to proved developed reserves in 2015, representing 23% of the Company's total PUD reserves as of December 31, 2014.

QEP estimates that its future development costs relating to the development of PUD reserves are approximately $438.9 million in 2016, $472.8 million in 2017, and $306.8 million in 2018. The scheduled PUD development costs are reduced from historical levels in conjunction with our efforts to reduce drilling and completion activities, gain operational efficiencies, slow production growth and preserve liquidity in the current commodity price environment. 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 availability under its 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 compliance oversight of a multi-functional reserves review committee reporting to the Company's Board of Directors. The Company retained Ryder Scott Company (RSC) and DeGolyer and MacNaughton (D&M), independent oil and gas reserve evaluation engineering consultants, to prepare the estimates of 100% 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 estimated 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 Company utilized RSC to prepare the estimates of 100% of the Company's total net proved reserves as of December 31, 2013.

The individual at RSC who was responsible for overseeing the preparation of QEP's reserve estimates as of December 31, 2015, for its Haynesville, Pinedale, Williston, Other Northern, Uinta and Midcontinent areas, 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 30 years of experience in the petroleum industry, including experience estimating and evaluating petroleum reserves. The individual at D&M who was responsible for overseeing the preparation of QEP’s Permian Division reserves estimates as of December 31, 2015, is a registered Professional Engineer in the State of Texas and graduated with a Bachelor of Science degree in Petroleum Engineering from the University of Texas at Austin in 1984. The individual has over 31 years of experience in the petroleum industry, including experience estimating and evaluating petroleum reserves. A more detailed letter including each individual's professional qualifications has been filed as part of Exhibit 99.1 to this report for RSC and as part of Exhibit 99.2 for D&M.

The individual at QEP responsible for insuring the accuracy of the reserve estimate preparation material provided to RSC and D&M and reviewing the estimates of reserves received from RSC and D&M is QEP's Chief Engineer. This individual is a member of the Society of Petroleum Engineers and graduated with a Bachelors of Science degree in Petroleum Engineering from North Dakota State University in 1994. This individual has over 21 years of experience in the petroleum industry, including more than 16 years reservoir engineering experience in most of the active domestic basins in the U.S.

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, volumetric methods or a combination of methods.

All of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. Performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of historical production data available through late 2015, in those cases where such data were considered to be definitive. For wells currently in production, 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.

Approximately 93% 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. The remaining 7% of such reserves was estimated by the volumetric method. The volumetric analysis utilizes pertinent well data furnished to RSC and D&M by QEP or obtained from available public data sources through late 2015. 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 16 – 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 Energy's proved reserves as of the end of each of the last three years.

In addition to this filing, QEP Energy will file reserve estimates as of December 31, 2015, 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 for only 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 – QEP Energy

The following table sets forth the net production volumes and field-level prices of gas, oil and NGL produced, and the related operating expenses, for the years ended December 31, 2015, 2014 and 2013:

	Year Ended December 31,		
	2015	2014	2013
Production volumes			
Gas (Bcf)	181.1	179.3	218.9
Oil (Mbbl)	19,582.3	17,146.5	10,209.7
NGL (Mbbl)	4,704.3	6,769.1	4,811.3
Total equivalent production (Bcfe)	326.8	322.7	309.0
Average field-level price [(1)]			
Gas (per Mcf)	$2.59	$4.33	$3.56
Oil (per bbl)	42.59	79.79	89.78
NGL (per bbl)	16.98	32.95	39.95
Lifting costs (per Mcfe)			
Lease operating expense	$0.73	$0.74	$0.59
Production taxes	0.35	0.63	0.51
Total lifting costs	$1.08	$1.37	$1.10

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

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

	Year Ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
Gas production volumes (Bcf)					
Northern Region					
Pinedale	87.5	75.0	80.0	12.5	(5.0)
Williston Basin	11.3	6.6	2.7	4.7	3.9
Uinta Basin	22.7	17.9	18.6	4.8	(0.7)
Other Northern	9.4	9.3	10.3	0.1	(1.0)
Southern Region					
Haynesville/Cotton Valley	43.2	49.5	71.8	(6.3)	(22.3)
Permian Basin	4.4	3.2	—	1.2	3.2
Midcontinent	2.6	17.8	35.5	(15.2)	(17.7)
Total production	181.1	179.3	218.9	1.8	(39.6)

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

	Year ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
Oil production volumes (Mbbl)					
Northern Region					
Pinedale	716.6	632.0	657.6	84.6	(25.6)
Williston Basin	14,871.8	13,130.9	7,026.2	1,740.9	6,104.7
Uinta Basin	848.6	893.3	924.9	(44.7)	(31.6)
Other Northern	186.5	200.9	237.7	(14.4)	(36.8)
Southern Region					
Haynesville/Cotton Valley	33.6	35.3	43.2	(1.7)	(7.9)
Permian Basin	2,791.2	1,582.2	—	1,209.0	1,582.2
Midcontinent	134.0	671.9	1,320.1	(537.9)	(648.2)
Total production	19,582.3	17,146.5	10,209.7	2,435.8	6,936.8

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

	Year ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
NGL production volumes (Mbbl)					
Northern Region					
Pinedale	1,528.6	3,350.2	1,787.5	(1,821.6)	1,562.7
Williston Basin	1,953.4	1,010.5	390.0	942.9	620.5
Uinta Basin	287.6	679.0	463.8	(391.4)	215.2
Other Northern	19.6	14.9	36.7	4.7	(21.8)
Southern Region					
Haynesville/Cotton Valley	28.6	37.3	21.3	(8.7)	16.0
Permian Basin	815.4	511.0	—	304.4	511.0
Midcontinent	71.1	1,166.2	2,112.0	(1,095.1)	(945.8)
Total production	4,704.3	6,769.1	4,811.3	(2,064.8)	1,957.8

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

	Year ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
Total production volumes (Bcfe)					
Northern Region					
Pinedale	101.0	98.9	94.7	2.1	4.2
Williston Basin	112.3	91.4	47.2	20.9	44.2
Uinta Basin	29.5	27.3	26.9	2.2	0.4
Other Northern	10.6	10.6	11.9	—	(1.3)
Southern Region					
Haynesville/Cotton Valley	43.6	49.9	72.2	(6.3)	(22.3)
Permian Basin	26.0	15.8	—	10.2	15.8
Midcontinent	3.8	28.8	56.1	(25.0)	(27.3)
Total production	326.8	322.7	309.0	4.1	13.7

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

	Year Ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
Average field-level gas price (per Mcf)					
Northern Region	$2.58	$4.26	$3.58	$(1.68)	$0.68
Southern Region	2.60	4.44	3.54	(1.84)	0.90
Average field-level gas price	2.59	4.33	3.56	(1.74)	0.77
Average field-level oil price (per bbl)					
Northern Region	$41.78	$78.87	$89.35	$(37.09)	$(10.48)
Southern Region	47.16	85.76	92.60	(38.60)	(6.84)
Average field-level oil price	42.59	79.79	89.78	(37.20)	(9.99)
Average field-level NGL price (per bbl)					
Northern Region	$18.06	$33.22	$46.56	$(15.16)	$(13.34)
Southern Region	12.49	32.15	31.65	(19.66)	0.50
Average field-level NGL price	16.98	32.95	39.95	(15.97)	(7.00)
Lease Operating Expense (per Mcfe)					
Northern Region	$0.66	$0.63	$0.60	$0.03	$0.03
Southern Region	0.97	0.90	0.57	0.07	0.33
Average production cost	0.73	0.74	0.59	(0.01)	0.15

Northern Region

Pinedale

Production from Pinedale increased 2% to 101.0 Bcfe during 2015 compared to 2014. This increase in production 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.

Production from Pinedale increased 4% to 98.9 Bcfe during 2014 compared to 2013. This increase in production was primarily a result of increased NGL production due to recovering ethane throughout the majority of 2014 compared to rejecting ethane throughout the majority of 2013.

During each of the three years ended December 31, 2015, 2014 and 2013, Pinedale's production represented 31% of QEP Energy's total production.

Williston Basin
In the Williston Basin, production increased 23% to 112.3 Bcfe during 2015 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 2014, production increased 94% to 91.4 Bcfe, compared to 2013, primarily due to increased oil and NGL production. The increase in production volumes was primarily attributable to ongoing development of the properties acquired in the Williston Basin in 2012, which contributed 6,347.5 Mbbls of increased oil and NGL volume. The remaining 377.7 Mbbls increase in 2014 related to increased development drilling on QEP's existing pre-acquisition acreage.

During the years ended December 31, 2015, 2014 and 2013, Williston Basin production represented 34%, 28%, and 15%, respectively, of QEP Energy's total production.

Uinta Basin
In the Uinta Basin, production increased 8% to 29.5 Bcfe during 2015 compared to 2014, due primarily 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 2014, production increased 1% to 27.3 Bcfe, compared to 2013, due primarily to increased NGL production as a result of recovering ethane throughout the majority of 2014 compared to rejecting ethane in the majority of 2013.

During the years ended December 31, 2015, 2014 and 2013, Uinta Basin production represented 9%, 8%, and 9%, respectively, of QEP Energy's total production.

Other Northern
QEP Energy's Other Northern production remained flat during 2015 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.

Other Northern production decreased 11% to 10.6 Bcfe during 2014 compared to 2013, due to declining production from older wells and lack of new drilling.

During the years ended December 31, 2015, and 2014, Other Northern production represented 3% of QEP Energy's total production, compared to 4% for the year ended December 31, 2013.

Southern Region

Haynesville/Cotton Valley
Production from the Haynesville Shale and Cotton Valley decreased 13% to 43.6 Bcfe during 2015 when compared to 2014. Decreased production was 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.

Production from the Haynesville Shale and Cotton Valley decreased 31% to 49.9 Bcfe during 2014 when compared to 2013. Decreased production was due to natural decline and the continued suspension of QEP's operated drilling program.

During the years ended December 31, 2015, 2014 and 2013, Haynesville/Cotton Valley's production comprised 13%, 15%, and 23%, respectively, of QEP Energy's total production.

Permian Basin

In February 2014, QEP Energy acquired approximately 26,500 net acres of producing and undeveloped oil and gas properties in the Permian Basin. Production from the Permian Basin increased 65% to 26.0 Bcfe during 2015 when compared to 2014, due to increased horizontal well development combined with a full year of production in 2015 compared to 10 months of production in 2014.

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

Midcontinent
Production in the Midcontinent decreased 87% to 3.8 Bcfe during 2015 when compared to 2014, due to divestitures of non-core properties in the second and fourth quarters of 2014.

Production in the Midcontinent decreased 49% to 28.8 Bcfe during 2014 compared to 2013, due to divestitures of non-core properties at the end of the second quarter of 2014.

During the years ended December 31, 2015, 2014 and 2013, Midcontinent production represented 1%, 9%, and 18% of QEP Energy's total production, respectively.

Productive Wells
The following table summarizes the Company's productive wells as of December 31, 2015, all of which are located in the U.S.:

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Northern Region						
Pinedale [(1)]	1,071	660.2	—	—	1,071	660.2
Williston Basin	—	—	756	292.8	756	292.8
Uinta Basin	697	511.8	1,527	198.4	2,224	710.2
Other Northern	517	199.0	27	9.2	544	208.2
Southern Region						
Haynesville/Cotton Valley	847	457.5	1	0.1	848	457.6
Permian Basin	—	—	375	347.7	375	347.7
Midcontinent	551	33.0	115	7.0	666	40.0
Total productive wells	3,683	1,861.5	2,801	855.2	6,484	2,716.7

(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 processing, a well is categorized as either a gas or an oil well based upon the ratio of gas to oil produced at the wellhead. 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, 2015. "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	171,987	115,053	78,797	17,540	250,784	132,593
Montana	37,817	15,649	332,686	58,038	370,503	73,687
New Mexico	7,740	4,266	24,971	2,476	32,711	6,742
North Dakota	204,319	68,167	170,833	55,704	375,152	123,871
South Dakota	40	40	203,558	107,551	203,598	107,591
Wyoming	306,886	204,348	97,653	52,658	404,539	257,006
Utah	218,244	166,382	214,179	139,184	432,423	305,566
Kansas	46,153	20,872	35,699	12,805	81,852	33,677
Louisiana	69,754	62,045	1,841	1,495	71,595	63,540
Oklahoma	62,222	36,192	93,882	15,332	156,104	51,524
Texas	31,410	22,393	90,529	43,914	121,939	66,307
Other	14,255	3,888	158,108	43,593	172,363	47,481
Total	1,170,827	719,295	1,502,736	550,290	2,673,563	1,269,585

(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 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,		
2016	19,806	18,226
2017	56,260	56,260
2018	54,034	13,047
2019	19,521	15,664
2020 and later	43,961	37,393
Total	193,582	140,590

Drilling Activity

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

	Developmental Wells				Exploratory Wells			
	Productive		Dry		Productive		Dry	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Year Ended December 31, 2015								
Northern Region								
Pinedale	107	68.1	—	—	—	—	—	—
Williston Basin	154	59.7	—	—	—	—	—	—
Uinta Basin	30	11.2	—	—	—	—	—	—
Other Northern	3	3.0	—	—	1	1.0	—	—
Southern Region								
Haynesville/Cotton Valley	24	3.2	—	—	—	—	—	—
Permian Basin	38	32.5	—	—	—	—	—	—
Midcontinent	4	0.1	—	—	—	—	—	—
Total	360	177.8	—	—	1	1.0	—	—
Year Ended December 31, 2014								
Northern Region								
Pinedale	116	82.4	—	—	—	—	—	—
Williston Basin	199	80.6	—	—	—	—	—	—
Uinta Basin	196	6.5	—	—	—	—	—	—
Other Northern	3	3.0	—	—	1	1.0	—	—
Southern Region								
Haynesville/Cotton Valley	40	3.2	1	0.3	—	—	—	—
Permian Basin	71	63.2	—	—	—	—	—	—
Midcontinent	32	2.3	—	—	—	—	—	—
Total	657	241.2	1	0.3	1	1.0	—	—
Year Ended December 31, 2013								
Northern Region								
Pinedale	111	61.5	—	—	—	—	—	—
Williston Basin	176	70.7	—	—	—	—	—	—
Uinta Basin	224	39.4	—	—	—	—	—	—
Other Northern	6	0.2	—	—	—	—	1	1.0
Southern Region								
Haynesville/Cotton Valley	11	3.4	—	—	—	—	—	—
Midcontinent	135	29.3	—	—	—	—	—	—
Total	663	204.5	—	—	—	—	1	1.0

The following table presents operated and non-operated well completions for the year ended December 31, 2015:

	Operated Completions		Non-operated Completions	
	Gross	Net	Gross	Net
Northern Region				
Pinedale[(1)]	107	68.1	—	—
Williston Basin	70	55.0	84	4.7
Uinta Basin	11	11.0	19	0.2
Other Northern	4	4.0	—	—
Southern Region				
Haynesville/Cotton Valley	—	—	24	3.2
Permian Basin[(2)]	36	31.6	2	0.9
Midcontinent	—	—	4	0.1

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(1) Gross completions includes eight wells for the year ended December 31, 2015, in which QEP only owns a small overriding royalty interest.

(2) Operated completions include eight gross, 7.4 net, vertical wells for the year ended December 31, 2015.

The following table presents operated and non-operated wells drilling and waiting on completion at December 31, 2015:

	Operated				Non-operated			
	Drilling		Waiting on completion		Drilling		Waiting on completion	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Northern Region								
Pinedale	8	5.0	20	12.5	—	—	—	—
Williston Basin	5	4.6	24	22.8	1	—	19	1.0
Uinta Basin	2	2.0	6	6.0	—	—	3	—
Other Northern	—	—	—	—	—	—	—	—
Southern Region								
Haynesville/Cotton Valley	—	—	—	—	—	—	6	1.3
Permian Basin	5	5.0	4	3.9	—	—	—	—
Midcontinent	—	—	—	—	—	—	2	0.1

QEP typically utilizes multi-well pad drilling where practical. Wells drilled are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location. In certain properties in the Northern Region, QEP typically suspends completion activities due to adverse weather conditions in the fourth quarter and resumes completion in the first quarter as weather conditions allow. As a result, QEP had 54 gross operated wells waiting on completion as of December 31, 2015.

Energy Marketing – QEP Marketing and Other

QEP Marketing owns and operates an underground gas storage reservoir in southwestern Wyoming (Clear Creek). Clear Creek has capacity of approximately 8 Bcf, comprised of approximately 4 Bcf of QEP Marketing-owned cushion gas and working gas storage capacity of about 4 Bcf.

In addition, QEP Marketing owns a membership interest in a gas gathering system located in Louisiana (Haynesville Gathering). Haynesville Gathering includes 200 miles of gas gathering facilities with approximate throughput capacity of 2,000 MMcf/d and a treating facility with throughput capacity of 600 MMcf/d. The system primarily provides services to QEP Energy.

Delivery Commitments – QEP Resources

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

Period	Delivery Commitments (millions of MMBtu)
2016	84.8
2017	14.7
2018	2.7
Thereafter	—

These commitments are physical delivery obligations with prices based on prevailing index prices for gas at the time of delivery. None of these commitments requires the Company to deliver 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 for some reason the Company's gas production is not sufficient to satisfy its firm delivery commitments, the Company believes it can purchase sufficient volumes of 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 gas deliveries.

In addition, at December 31, 2015, the Company did not have a significant amount of production from QEP Energy'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.

ITEM 3. LEGAL PROCEEDINGS

Yannick Gagné Lawsuit and Related Suits – Injured parties filed the initial class action lawsuit in July 2013, and plaintiffs added QEP and other operators as defendants in February 2014. Plaintiffs in this initial lawsuit and subsequent related lawsuits sought to obtain compensation for persons who sustained damages as a result of the July 6, 2013, train derailment in Lac-Mégantic, Quebec, which resulted in substantial loss of life and property. The rail company that transported the crude oil filed for bankruptcy protection following the accident. The plaintiffs contended that QEP, and other producer defendants, sold Bakken crude oil to third-party purchasers in North Dakota, who resold the oil and transported it on the derailed train. Plaintiffs alleged that QEP and the producer defendants, among other things, failed to ensure that the oil was adequately processed to remove volatile gases and vapors, failed to take reasonable care to ensure that the oil was properly labeled and shipped and failed to identify the risk of the train derailment and take action to prevent it. The plaintiffs sought unspecified damages. During the third quarter of 2015, QEP was served with additional complaints in state and federal courts in Maine, Texas and Illinois, each of which made similar claims to those in the Yannick Gagné case. In March 2015, many of the defendants, including QEP, reached a conditional settlement agreement with trustees in both Canadian and U.S. bankruptcy courts to resolve all claims, including all claims raised in all related tort actions in Canada and the United States. The conditions were met in early November 2015, and at that time QEP paid a settlement amount (a significant portion of which was covered by QEP's insurers) and received a full release of all known and unknown claims. The settlement amount paid by QEP was not material to QEP's financial position or results of operations.

Environmental Matters – 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 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, 2016, QEP had 6,015 shareholders of record. The 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. In February 2016, in response to the current commodity price environment, the Board of Directors indefinitely suspended the payment of quarterly dividends.

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 2015 and 2014:

	High price (per share)	Low price	Dividend
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
2014			
First quarter	$33.32	$25.93	$0.02
Second quarter	34.60	29.59	0.02
Third quarter	35.91	30.33	0.02
Fourth quarter	31.00	18.15	0.02
Total			$0.08

Stock Performance Graph

The following stock performance information in this Item 5 of this Annual Report on Form 10-K 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 2015, QEP made changes to its peer group to remove Noble Energy, Inc., Quicksilver Resources, Inc. and Pioneer Natural Resources Company due to dissimilar financial characteristics. In addition, Forest Oil Corporation was acquired in December 2014 and therefore was removed from the peer group. Laredo Petroleum, Inc., Oasis Petroleum Inc. and Sandridge Energy Inc. were added to QEP's peer group, which is comprised of U.S. companies with similar size and scope to QEP.

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

Cabot Oil & Gas Corporation	Pioneer Natural Resources Company
Cimarex Energy Company	Range Resources Corporation
Concho Resources Inc.	SM Energy Company
Denbury Resources Inc.	Southwestern Energy Company
Forest Oil Corporation	Ultra Petroleum Corporation

Newfield Exploration Company	Whiting Petroleum Corporation
Noble Energy, Inc.	WPX Energy, Inc.
Quicksilver Resources, Inc.	

After the change in peer companies, QEP's 2015 peer group consisted of the following:

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.

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 July 1, 2010, which is the date when QEP's common stock began trading on the NYSE;
- 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 were reinvested on the relevant payment dates.

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, 2015 - October 31, 2015	17,297	$ 24.01	—	$400.3
November 1, 2015 - November 30, 2015	3,524	$ 16.13	—	$400.3
December 1, 2015 - December 31, 2015	194	$ 12.43	—	$—

(1) All of the shares purchased during the three-month period ended December 31, 2015, were acquired from employees in connection with the settlement of income tax and related benefit withholding obligations arising from vesting of restricted stock grants.

In 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. This program expired on December 31, 2015. During the year ended December 31, 2015, no shares were repurchased under this program.

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data for the five years ended December 31, 2015, is provided in the table below. Our financial results for prior periods have been recast, in accordance with GAAP, to reflect the impact of the Midstream Sale and the revisions to our revenues from purchased oil sales. See footnotes (4) and (5) to the table below. Refer to Items 7 and 8 in Part II of this Annual Report on Form 10-K for further discussion of the factors affecting the comparability of the Company's financial data.

	Year Ended December 31,				
	2015 [1][2]	2014 [1][2]	2013[1]	2012[1]	2011
	(in millions, except per share amounts)				
Results of Operations					
Revenues [3][4]	$2,018.6	$3,293.2	$2,685.1	$2,071.7	$2,835.0
Operating income (loss)	(377.6)	(847.3)	203.0	(321.2)	267.2
Income (loss) from continuing operations	(149.4)	(409.5)	52.1	2.4	118.1
Net income from discontinued operations, net of income tax[5]	—	1,193.9	107.3	125.9	149.1
Net income (loss)	(149.4)	784.4	159.4	128.3	267.2
Earnings (loss) per common share					
Basic from continuing operations	$(0.85)	$(2.28)	$0.29	$0.01	$0.67
Basic from discontinued operations[5]	—	6.64	0.60	0.71	0.84
Basic total	$(0.85)	$4.36	$0.89	$0.72	$1.51
Diluted from continuing operations	$(0.85)	$(2.28)	$0.29	$0.01	$0.66
Diluted from discontinued operations[5]	—	6.64	0.60	0.71	0.84
Diluted total	$(0.85)	$4.36	$0.89	$0.72	$1.50
Weighted-average common shares outstanding					
Used in basic calculation	176.6	179.8	179.2	177.8	176.5
Used in diluted calculation	176.6	179.8	179.5	178.7	178.4
Dividends per common share	$0.08	$0.08	$0.08	$0.08	$0.08
Financial Position					
Total Assets at December 31,	$8,425.5	$9,286.8	$9,408.9	$9,108.5	$7,442.7
Capitalization at December 31,					
Long-term debt	2,218.8	2,218.1	2,997.5	3,206.9	1,679.4
Total equity	3,947.9	4,075.3	3,876.8	3,313.7	3,352.1
Total Capitalization	$6,166.7	$6,293.4	$6,874.3	$6,520.6	$5,031.5
Cash Flow from Operations					
Net cash provided by operating activities	$481.3	$1,542.5	$1,191.7	$1,296.0	$1,292.6
Capital expenditures	(1,239.4)	(2,726.4)	(1,602.6)	(2,799.7)	(1,431.1)
Net cash provided by (used in) investing activities	(1,217.6)	578.2	(1,441.5)	(2,794.5)	(1,422.9)
Net cash provided by (used in) financing activities	(47.7)	(990.6)	279.8	1,498.5	130.3
Non-GAAP Measure					
Adjusted EBITDA [6]	$1,029.3	$1,582.7	$1,536.7	1,409.0	1,380.7

(1) During the years ended December 31, 2015, 2014, 2013 and 2012, the results are impacted by the Company's acquisition of oil and gas properties in the Williston Basin for an aggregate purchase price of $1.4 billion, which occurred on September 27, 2012.

(2) During the years ended December 31, 2015 and 2014, the results are impacted by the Permian Basin Acquisition, which occurred on February 25, 2014, and the property sales in the Midcontinent, which occurred during the second and fourth quarters 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 Permian Basin Acquisition and property divestitures.

(3) Revenue for the year ended December 31, 2011, reflects the impact of QEP's settled derivative contracts, which during the years ended December 31, 2015, 2014, 2013 and 2012, is reflected below operating income (loss). See Note 7 – Derivative Contracts, in Item 8 of Part II of this Annual Report on Form 10-K for detailed information on derivative contract settlements in the years ended December 31, 2015, 2014 and 2013.

(4) In the fourth quarter of 2015, the Company determined that certain purchased oil transactions that were included in "Revenues" on a gross basis for the year ended December 31, 2014, should have been reported net, as the transactions were with the same counterparty and were entered into in contemplation of one another. See Note 1 – Summary of Significant Accounting Policies in Item 8 of Part II of this Annual Report on Form 10-K for additional information. The Company has recast its revenues for the year ended December 31, 2014, to conform to the presentation for the year ended December 31, 2015.

(5) In December 2014, QEP completed the Midstream Sale. QEP Field Services' financial results (excluding results of the Haynesville gathering system) have been reflected as discontinued operations and all prior periods have been reclassified.

(6) 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 non-cash and/or non-recurring items. Management focuses on Adjusted EBITDA to assess the Company's operating results. Management believes Adjusted EBITDA is an important measure for comparing the Company's financial performance to other oil and gas producing companies. Because not all companies use identical calculations, our presentation of Adjusted EBITDA may not be comparable to other similarly titled measures of other companies.

The following table reconciles QEP's net income to Adjusted EBITDA:

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(in millions)				
Net income (loss)	$(149.4)	$784.4	$159.4	$128.3	$267.2
Net income from discontinued operations, net of tax	—	(1,193.9)	(107.3)	(125.9)	(149.1)
Net income (loss) from continuing operations	(149.4)	(409.5)	52.1	2.4	118.1
Unrealized (gains) losses on derivative contracts	183.7	(374.4)	88.7	(63.2)	(117.7)
Net (gain) loss from asset sales	(4.6)	148.6	(103.5)	(1.2)	(1.4)
Interest and other income	(3.0)	(12.8)	(15.2)	(15.0)	(9.2)
Income tax provision (benefit)	(93.6)	(232.5)	60.1	(1.9)	65.5
Interest expense	145.6	169.1	165.1	126.3	92.1
Accrued litigation loss contingency	—	—	—	115.0	—
Loss from early extinguishment of debt	—	2.0	—	0.6	0.7
Pension curtailment (1)	11.2	—	—	—	—
Depreciation, depletion and amortization	881.1	994.7	963.8	850.2	716.9
Impairment	55.6	1,143.2	93.0	133.0	218.2
Exploration expenses	2.7	9.9	11.9	11.2	10.5
Adjusted EBITDA from continuing operations	1,029.3	1,438.3	1,316.0	1,157.4	1,093.7
Adjusted EBITDA from discontinued operations (2)	—	144.4	220.7	251.6	287.0
Adjusted EBITDA	$1,029.3	$1,582.7	$1,536.7	$1,409.0	$1,380.7

(1) The pension curtailment was a non-cash expense incurred during the year ended December 31, 2015, due to changes 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 for additional information). The Company believes that the pension curtailment does not reflect expected future operating performance or provide meaningful comparisons to past operating performance and therefore has excluded the loss from the calculation of Adjusted EBITDA.

(2) See Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, for a reconciliation of Adjusted EBITDA from discontinued operations to Net Income attributable to QEP from discontinued operations.

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 a 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 2014 Annual Report on Form 10-K/A filing, and analyzes the changes in the results of operations between the years ended December 31, 2015 and 2014, and between the years ended December 31, 2014 and 2013.

OVERVIEW

QEP Resources, Inc. (QEP or the Company) is a holding company with two principal subsidiaries, QEP Energy Company and QEP Marketing Company, which are engaged in two primary lines of business: (i) oil and gas exploration and production (QEP Energy) and (ii) oil and gas marketing, operation of a gas gathering system and an underground gas storage facility and corporate activities (QEP Marketing and Other).

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 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. that provide a solid base for growth in organic production and reserves.

While historically a natural gas producer, in recent years the Company has increased its focus on growing the relative proportion of oil and NGL production in its exploration and production (E&P) business. During 2015, QEP Energy increased oil production by 14% compared to 2014. Additionally, oil and NGL production represented 45% of total production during the year ended December 31, 2015, compared to 44% during the year ended December 31, 2014, and 29% during the year ended December 31, 2013.

QEP Marketing Segment

Effective January 1, 2016, QEP terminated its contracts for resale and marketing transactions between its wholly owned subsidiaries, QEP Marketing and QEP Energy. As a result, QEP Energy will market its own gas, oil and NGL production. In addition, substantially all of QEP Marketing's third-party purchase and sale agreements and gathering, processing and transportation contracts have been assigned to QEP Energy, except those contracts related to natural gas storage activities and Haynesville gathering system (Haynesville Gathering). The change in affiliate transactions will simplify our business processes and financial statements by eliminating the majority of intercompany transactions. QEP also conducted a segment analysis in accordance with Accounting Standards Codification (ASC) Topic 280, Segment Reporting, and based on the changes discussed above, determined that QEP has one reportable segment after January 1, 2016. The elimination of the affiliate transactions has no impact to historical net income. However, since revenues and expenses were historically reported gross for working interest owner products in accordance with principal-agent considerations, QEP will report lower resale revenue and expenses in future periods.

The remaining third party resale activity will be reported in “Other revenues” and "Gathering and other expense" on the Consolidated Statement of Operations.

Discontinued Operations

On December 2, 2014, the Company closed the sale of 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 QEP Field Services Company (QEP Field Services) reporting segment, excluding the retained ownership of Haynesville Gathering, was classified as a discontinued operation on the Consolidated Statement of Operations and the Notes accompanying the

Consolidated Financial Statements. For reporting purposes, Haynesville Gathering has been added to the QEP Marketing and Other segment.

Acquisitions

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's operated wells and undeveloped acreage.

On February 25, 2014, QEP Energy acquired oil and gas properties in the Permian Basin of Texas 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 Energy.

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, enhance its ability to pursue acquisition opportunities.

Divestitures

The Company periodically divests select non-core assets. In 2015, QEP sold its interest in certain non-core properties in the Midcontinent and Other Northern areas for aggregate proceeds of $31.7 million. In 2014, QEP sold its interest in certain non-core properties in southern Oklahoma, the Midcontinent and the Williston Basin for aggregate proceeds of approximately $783.8 million. In 2013, QEP divested of certain non-core properties in the Midcontinent and Northern Regions resulting in aggregate proceeds of $205.8 million.

Financial and Operating Highlights

Our financial and operating highlights for 2015 are as follows:

- Achieved record equivalent production of 326.8 Bcfe, a 1% increase over 2014;
- Increased oil production to 19.6 MMbbls, a 14% increase over 2014, including 76% growth in the Permian Basin and 13% growth in the Williston Basin;
- Increased natural gas production to 181.1 Bcf, including record production in Pinedale;
- Generated a net loss of $149.4 million, or $0.85 per diluted share;
- Generated $1,029.3 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), of which $1,027.1 million was contributed by QEP Energy;
- Incurred capital expenditures (excluding property acquisitions) of $1,011.9 million, a 41% reduction from 2014;
- Reduced general and administrative expenses by $23.3 million, or 11%;
- Received field-level prices that were 42% lower than in 2014, however, our commodity derivative contracts offset 19% of this decrease; and
- Maintained $376.1 million in cash and cash equivalents and had no borrowings under our revolving credit facility.

Outlook

In response to the commodity price environment, in 2015 we reduced drilling and completion activities, slowed production growth, reduced costs and preserved our liquidity. We plan to continue these strategies in 2016. We are focused on driving improved operating performance by optimizing reservoir development, enhancing well completion designs, and aggressively pursuing cost reductions.

Based on current commodity prices, we expect to be able to fund our planned capital program with cash on hand, operating cash flow and availability under the credit facility. Our total capital expenditures for 2016 are expected to be approximately $475.0 million, a decrease of over 50% from 2015 capital expenditures. With this capital program we expect total equivalent production to be relatively flat compared to 2015. We plan to continuously evaluate our level of drilling activity in light of both commodity prices and changes we are able to make to our costs of operations and adjust our capital spending program as appropriate. See "Cash Flow from Investing Activities" for further discussion of our capital expenditures. We will also continue to pursue acquisitions and divest of non-core properties.

Factors Affecting Results of Operations

Gas, Oil and NGL Prices
Changes in the market prices for gas, oil and NGL directly impact many aspects of QEP's business, including its financial condition, revenues, results of operations, planned drilling 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 natural gas properties. Historically, field-level prices received for QEP's gas, oil and NGL production have been volatile and unpredictable, and that volatility is expected to continue.

In recent years, domestic crude oil and natural gas supplies have grown dramatically, driven by advances in drilling and completion technologies, including horizontal drilling and multi-stage hydraulic fracturing. These changes have allowed producers to extract increased quantities of hydrocarbons from shale, tight sand formations, and other unconventional reservoirs. Increased natural gas supplies, particularly in the eastern portion of the country, have resulted in downward pressure on U.S. natural gas prices and a high degree of pricing variability among different regional natural gas pricing hubs. High natural gas demand in 2014, driven primarily by unusually cold winter weather, resulted in improved natural gas prices in the first half of 2014, but continued growth in production, a more normal winter during the 2014-2015 heating season, and adequate storage levels led to natural gas price declines later in the year, which continued throughout 2015 and into 2016. Similarly, growth in U.S. oil production, global crude oil supplies that exceed global demand, a strong U.S. dollar and the failure of the Organization of Petroleum Exporting Countries (OPEC) countries to cut production, led to a dramatic weakening of global oil prices starting in late 2014, which continued throughout 2015 and into 2016.

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 crude oil prices, have declined consistently with weakening oil prices, while ethane and propane prices have experienced greater declines as a result of growing North American oversupply. In addition, QEP's 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 an 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 rejects ethane from the NGL stream.

During 2015, commodity prices were volatile as the NYMEX WTI oil monthly average spot price was as high as $59.82 per barrel in June 2015 and as low as $37.19 per barrel in December 2015, and the NYMEX HH natural gas one-month future price was a high of $3.08 in January 2015 and a low of $2.06 per MMBtu in November 2015. During 2014, the NYMEX WTI oil monthly average spot price was as high as $105.79 per barrel in June 2014 and as low as $59.29 per barrel in December 2014, while the NYMEX HH natural gas one-month future price was as high as $5.15 per MMBtu in February 2014 and as low as $3.65 per MMBtu in November 2014.

Due to increased global economic uncertainty and the corresponding volatility of commodity prices, QEP has built a strong liquidity position to ensure financial flexibility and has reduced drilling and completion activity and planned capital expenditures. 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, 2015, assuming forecasted 2016 annual production of approximately 314 Bcfe, QEP Energy had approximately 51% of its forecasted gas equivalent production covered with fixed-price swaps, including 71% of its forecasted gas production and 34% of its forecasted oil production. QEP entered into additional derivative contracts in 2015 and early 2016, but the average swap price of its derivative portfolio is significantly lower than the contracts entered into prior to 2015 and, therefore, will not contribute as much to QEP's net realized prices for 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.

Global Geopolitical and Macroeconomic Factors
QEP continues to monitor the global economy, including Europe's economic outlook; political unrest in Eastern Europe, the Middle East, and Africa; slowing growth in Asia, particularly in China; the United States' federal budget deficit; changes in regulatory oversight policy; commodity price volatility; the impact of rising 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 gas, oil and NGL supply, demand and prices and the Company's ability to continue its planned drilling programs on federal and Native American lands and could materially impact the Company's financial position, results of operations and cash flow from operations.

Supply, Demand and Other Market Risk Factors
Increased oil production in the U.S. over the last five years combined with various other global factors have led to substantially lower oil prices. According to data from the Energy Information Administration (EIA), U.S. oil production has increased by approximately four million barrels per day, or approximately 70%, since 2011. International oil supply disruptions in previous years have prevented oversupply and a corresponding negative price impact, but reduced supply disruptions combined with softening global demand, a stronger U.S. dollar, and other factors have led to substantially lower oil prices starting in late 2014 that have continued throughout 2015 and into 2016. As a result, many oil producers around the world are dramatically reducing activity.

In December 2015, the U.S. lifted a 40-year ban on the export of crude oil. U.S. producers now have access to a wider market, and the U.S. could become a significant exporter of oil if the necessary infrastructure is built to support oil exports. As a result, oil and gas prices in the future may be cheaper than they would otherwise be. QEP anticipates global oil prices will improve in the coming years as supply growth moderates due to lower level of investment and modest demand increases. 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.

During the last five years, the U.S. natural gas directed drilling rig count has decreased as producers reduced drilling activity for dry natural gas in response to lower natural gas prices and directed investment toward oil and liquid-rich projects. Over the same period of time, U.S. natural gas production has continued to grow, particularly in the Marcellus Shale region, as efficiency gains have allowed more wells to be drilled and completed per operating rig, higher per-well natural gas production from horizontal wells as a result of investment focused on more prolific resources, and increased amounts of natural gas produced in association with crude oil. As a result, U.S. natural gas production continued to increase into 2015, despite the gradually decreasing rig-count. Strong natural gas demand from electric power generation, cold winter weather during the 2013-2014 heating season, and other demand sources caused a general firming of natural gas prices during the second half of 2013 and into the first half of 2014. Natural gas prices weakened in the second half of 2014 and continued to decline throughout 2015 and into 2016 due to more typical winter season demand levels and continued increases in supply. QEP expects U.S. natural gas prices to remain range-bound over the near term. Relatively low natural gas prices in recent years have caused U.S. E&P companies, including QEP, to shift capital investments away from predominantly dry gas areas toward plays that produce crude oil, condensate and liquids-rich gas.

The reallocation of drilling capital to liquids-rich gas and crude oil has caused domestic NGL production to increase dramatically. Increased NGL production has contributed to a weakening of domestic NGL prices, particularly ethane and propane. QEP expects that ethane prices will continue to be range-bound and ethane processing economics challenged until new ethylene crackers and export facilities are built. Propane prices have declined as a result of abnormally high inventory levels, limited domestic demand growth and insufficient export capacity. The prices of heavier components of the NGL barrel have weakened as a result of the decline in crude oil prices.

In addition, transportation, refining, or other infrastructure constraints could introduce significant price differentials between regional markets where QEP sells its production and national (NYMEX HH at Henry Hub or NYMEX WTI at Cushing) and global (ICE Brent) markets. Because of the global and regional price volatility and the uncertainty around the gas, oil and NGL price environments, QEP continues to manage its capital spending program and liquidity accordingly and has scaled back its capital expenditure budget and drilling and completion activities planned for 2016.

Potential for Asset Impairments

The carrying value of the Company's properties is sensitive to declines in gas, oil and NGL prices. These assets are at risk of impairment if future prices for gas, oil 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 gas, oil 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. Forward prices in mid February

2016 have declined subsequent to the test for impairment at December 31, 2015. If forward prices remain at mid February 2016 levels, we have approximately $1.8 billion of proved property net book value, as of December 31, 2015, primarily associated with our Pinedale field, at risk for impairment. The actual amount of impairment incurred, if any, for these properties will depend on a variety of factors including, but not limited to, subsequent forward price curve changes, the additional risk-adjusted value of probable and possible reserves associated with the properties, weighted-average cost of capital, operating cost estimates and future capital expenditure estimates. Additionally, a further decrease from mid February levels in forward gas, oil or NGL prices could result in additional properties being at risk for impairment.

During the year ended December 31, 2015, the Company recorded impairments of $55.6 million primarily due to impairments of proved properties 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 property in the Southern Region associated with lower future prices at December 31, 2014. During the year ended December 31, 2013, impairments were $93.0 million primarily due to impairments of goodwill and unproved properties associated with expiring leases and future development plans. For additional information see Item 1A – Risk Factors, of Part I and see Item 8 of Part II, Note 1 – Summary of Significant Accounting Policies, 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. In addition, existing wells that offset newly drilled wells may be temporarily shut-in during the completion process. As a result, multi-well pad drilling delays the commencement of production, which may cause volatility in QEP’s quarterly operating results.

RESULTS OF OPERATIONS

Our financial results for prior periods 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 detailed information on the Midstream Sale.

Net Income

The following table provides a summary of net income (loss) by line of business:

	Year Ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
	(in millions, except per share amounts)				
QEP Energy	$(182.9)	$(432.5)	$25.6	$249.6	$(458.1)
QEP Marketing and Other	33.5	23.0	26.5	10.5	(3.5)
Net income (loss) from continuing operations	(149.4)	(409.5)	52.1	260.1	(461.6)
Net income from discontinued operations, net of income tax	—	1,193.9	107.3	(1,193.9)	1,086.6
Net income (loss)	$(149.4)	$784.4	$159.4	$(933.8)	$625.0
Earnings (loss) per diluted share from continuing operations	$(0.85)	$(2.28)	$0.29	$1.43	$(2.57)
Earnings per diluted share from discontinued operations	—	6.64	0.60	(6.64)	6.04
Diluted earnings (loss) per share	$(0.85)	$4.36	$0.89	$(5.21)	$3.47

Average diluted shares	176.6	179.8	179.5	(3.2	) 0.3

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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 due to a $249.6 million decrease in QEP Energy's net loss and a $10.5 million increase in QEP Marketing and Other's net income. QEP Energy's decrease in net loss 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 $9.7 million during 2015 compared to a net loss from asset sales of $148.6 million during 2014 and lower operating expenses during the year ended December 31, 2015 compared to the year ended December 31, 2014. These changes were partially offset by a decrease in average field-level prices for gas, oil and NGL, a 31% decrease in NGL production and a $93.0 million decrease in realized and unrealized gains on derivative contracts. QEP Marketing and Other's net income increased during the year ended December 31, 2015 compared to 2014, primarily due to lower interest expense due to lower average debt levels during the year ended December 31, 2015, and a decrease in net loss from resale margin.

QEP generated a net loss from continuing operations during the year ended December 31, 2014, of $409.5 million, or $2.28 per diluted share, compared to net income from continuing operations of $52.1 million, or $0.29 per diluted share, in 2013. The net loss during 2014 was due to a decrease $458.1 million at QEP Energy and a decrease of $3.5 million at QEP Marketing and Other. The net loss at QEP Energy during 2014 was primarily attributable to an increase in impairment expense of $1,050.2 million related to higher impairments in 2014, a loss on sale of assets of $148.6 million in 2014 compared to a gain on sale of $104.1 million in 2013 and lower realized gains on derivative contracts of $150.8 million. These additional expenses incurred at QEP Energy during 2014 were partially offset by an increase in unrealized gains on derivative contracts of $458.9 million and increased oil revenue of $451.6 million due to a 68% increase in oil production. QEP Marketing and Other's net income is related to intercompany interest income from interest expense charges to QEP's subsidiaries.

Adjusted EBITDA

Management believes Adjusted EBITDA (a non-GAAP measure) is an important measure of the Company’s financial and operating performance that allows investors to understand how management evaluates financial performance to make operating decisions and allocate resources. 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 non-cash and/or non-recurring items.

The following table provides a summary of Adjusted EBITDA by line of business:

	Year Ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
	(in millions)				
QEP Energy	$1,027.1	$1,437.0	$1,301.8	$(409.9)	$135.2
QEP Marketing and Other	2.2	1.3	14.2	0.9	(12.9)
Adjusted EBITDA from continuing operations	1,029.3	1,438.3	1,316.0	(409.0)	122.3
Adjusted EBITDA from discontinued operations	—	144.4	220.7	(144.4)	(76.3)
Adjusted EBITDA	$1,029.3	$1,582.7	$1,536.7	$(553.4)	$46.0

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 42% decrease in the average field-level price and a 31% decrease in NGL production, partially offset by a 14% increase in oil production, a slight increase in gas production and higher realized gains on derivative contracts.

Adjusted EBITDA from continuing operations increased to $1,438.3 million during the year ended December 31, 2014 compared to $1,316.0 million in 2013, due to a 68% increase in oil production and a 41% increase in NGL production, partially offset by an 18% decrease in gas production and a 10% and 18% decrease in oil and NGL net realized prices, respectively, at QEP Energy.

The following tables are reconciliations of Adjusted EBITDA to net income (loss) attributable to QEP, the most comparable GAAP financial measure, for the years ended December 31, 2015, 2014 and 2013:

	QEP Energy	QEP Marketing and Other [1]	Continuing Operations	Discontinued Operations	QEP Consolidated
	(in millions)				
Year ended December 31, 2015					
Net income (loss)	$(182.9)	$33.5	$(149.4)	$—	$(149.4)
Unrealized (gain) loss on derivative contracts	182.9	0.8	183.7	—	183.7
Net (gain) loss from asset sales	(9.7)	5.1	(4.6)	—	(4.6)
Interest and other income	(1.9)	(1.1)	(3.0)	—	(3.0)
Income tax provision (benefit)	(105.9)	12.3	(93.6)	—	(93.6)
Interest expense (income)	204.5	(58.9)	145.6	—	145.6
Pension curtailment[2]	11.0	0.2	11.2	—	11.2
Depreciation, depletion and amortization	870.8	10.3	881.1	—	881.1
Impairment	55.6	—	55.6	—	55.6
Exploration expenses	2.7	—	2.7	—	2.7
Adjusted EBITDA	$1,027.1	$2.2	$1,029.3	$—	$1,029.3
Year ended December 31, 2014					
Net income (loss)	$(432.5)	$23.0	$(409.5)	$1,193.9	$784.4
Unrealized (gain) loss on derivative contracts	(368.2)	(6.2)	(374.4)	—	(374.4)
Net (gain) loss from asset sales	148.6	—	148.6	(1,793.4)	(1,644.8)
Interest and other income	(11.8)	(1.0)	(12.8)	(0.3)	(13.1)
Income tax provision (benefit)	(246.9)	14.4	(232.5)	708.2	475.7
Interest expense (income)[3]	210.3	(41.2)	169.1	2.3	171.4
Loss on early extinguishment of debt	—	2.0	2.0	2.4	4.4
Depreciation, depletion and amortization[4]	984.4	10.3	994.7	31.3	1,026.0
Impairment	1,143.2	—	1,143.2	—	1,143.2
Exploration expenses	9.9	—	9.9	—	9.9
Adjusted EBITDA	$1,437.0	$1.3	$1,438.3	$144.4	$1,582.7
Year ended December 31, 2013					
Net income (loss)	$25.6	$26.5	$52.1	$107.3	$159.4
Unrealized (gain) loss on derivative contracts	90.7	(2.0)	88.7	—	88.7
Net (gain) loss from asset sales	(104.1)	0.6	(103.5)	0.5	(103.0)
Interest and other income	(3.6)	(11.6)	(15.2)	10.0	(5.2)
Income tax provision (benefit)	41.5	18.6	60.1	59.7	119.8
Interest expense (income)[3]	192.6	(27.5)	165.1	(2.2)	162.9
Depreciation, depletion and amortization[4]	954.2	9.6	963.8	45.4	1,009.2
Impairment	93.0	—	93.0	—	93.0
Exploration expenses	11.9	—	11.9	—	11.9
Adjusted EBITDA	$1,301.8	$14.2	$1,316.0	$220.7	$1,536.7

(1) Includes intercompany eliminations.

(2) The pension curtailment was a non-cash expense incurred during the year ended December 31, 2015, due to changes 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 for additional information). The Company believes that the pension curtailment does not reflect expected future operating performance or provide meaningful comparisons to past operating performance and therefore has excluded the loss from the calculation of QEP's Adjusted EBITDA.

(3) Excludes noncontrolling interest's share of $1.5 million and $0.4 million during the years ended December 31, 2014, and 2013, respectively, of interest expense attributable to QEP Midstream.

(4) Excludes noncontrolling interests' share of $14.6 million and $6.8 million during the years ended December 31, 2014, and 2013, respectively, of depreciation, depletion and amortization attributable to Rendezvous Gas Services, L.L.C and QEP Midstream.

QEP ENERGY

The following table provides a summary of QEP Energy's financial and operating results:

	Year Ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
	(in millions)				
REVENUES					
Gas sales	$468.5	$776.4	$779.0	$(307.9)	$(2.6)
Oil sales	834.0	1,368.2	916.6	(534.2)	451.6
NGL sales	79.9	223.1	192.2	(143.2)	30.9
Purchased gas sales	86.8	150.0	191.6	(63.2)	(41.6)
Other	8.0	6.9	13.4	1.1	(6.5)
Total Revenues	1,477.2	2,524.6	2,092.8	(1,047.4)	431.8
OPERATING EXPENSES					
Purchased gas expense	87.3	150.0	197.1	(62.7)	(47.1)
Lease operating expense	238.8	240.1	181.3	(1.3)	58.8
Gas, oil and NGL transportation and other handling costs	300.2	291.5	242.2	8.7	49.3
General and administrative	176.8	201.3	160.6	(24.5)	40.7
Production and property taxes	115.1	204.0	159.8	(88.9)	44.2
Depreciation, depletion and amortization	870.8	984.4	954.2	(113.6)	30.2
Exploration expenses	2.7	9.9	11.9	(7.2)	(2.0)
Impairment	55.6	1,143.2	93.0	(1,087.6)	1,050.2
Total Operating Expenses	1,847.3	3,224.4	2,000.1	(1,377.1)	1,224.3
Net gain (loss) from asset sales	9.7	(148.6)	104.1	158.3	(252.7)
OPERATING INCOME (LOSS)	(360.4)	(848.4)	196.8	488.0	(1,045.2)
Realized gain (loss) on derivative instruments	457.1	(1.0)	149.8	458.1	(150.8)
Unrealized (loss) gain on derivative instruments	(182.9)	368.2	(90.7)	(551.1)	458.9
Interest and other income (loss)	1.9	11.8	3.6	(9.9)	8.2
Income from unconsolidated affiliates	—	0.3	0.2	(0.3)	0.1
Interest expense	(204.5)	(210.3)	(192.6)	5.8	(17.7)
NET INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(288.8)	(679.4)	67.1	390.6	(746.5)
Income tax (provision) benefit	105.9	246.9	(41.5)	(141.0)	288.4
NET INCOME (LOSS)	$(182.9)	$(432.5)	$25.6	$249.6	$(458.1)
Production volumes					
Gas (Bcf)	181.1	179.3	218.9	1.8	(39.6)
Oil (Mbbl)	19,582.3	17,146.5	10,209.7	2,435.8	6,936.8
NGL (Mbbl)	4,704.3	6,769.1	4,811.3	(2,064.8)	1,957.8
Total production (Bcfe)	326.8	322.7	309.0	4.1	13.7
Daily combined production (MMcfe/d)	895.3	884.0	846.5	11.3	37.5

Revenue

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

	Year Ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
Gas (per Mcf)					
Average field-level price	$2.59	$4.33	$3.56	$(1.74)	$0.77
Commodity derivative impact	0.57	(0.09)	0.69	0.66	(0.78)
Net realized price	$3.16	$4.24	$4.25	$(1.08)	$(0.01)
Oil (per bbl)					
Average field-level price	$42.59	$79.79	$89.78	$(37.20)	$(9.99)
Commodity derivative impact	18.06	0.92	(0.22)	17.14	1.14
Net realized price	$60.65	$80.71	$89.56	$(20.06)	$(8.85)
NGL (per bbl)					
Average field-level price	$16.98	$32.95	$39.95	$(15.97)	$(7.00)
Commodity derivative impact	—	—	—	—	—
Net realized price	$16.98	$32.95	$39.95	$(15.97)	$(7.00)
Average net equivalent price (per Mcfe)					
Average field-level price	$4.23	$7.34	$6.11	$(3.11)	$1.23
Commodity derivative impact	1.40	(0.01)	0.48	1.41	(0.49)
Net realized price	$5.63	$7.33	$6.59	$(1.70)	$0.74

Revenue, Volume and Price Variance Analysis

The following table shows volume and price related changes for each of QEP Energy's major revenue components for the year ended December 31, 2015 compared to the years ended December 31, 2014 and 2013:

	Gas	Oil	NGL	Total
	(in millions)			
QEP Energy Production Revenues				
Year ended December 31, 2013 revenues	$779.0	$916.6	$192.2	$1,887.8
Changes associated with volumes [(1)]	(140.6)	622.8	78.2	560.4
Changes associated with prices [(2)]	138.0	(171.2)	(47.3)	(80.5)
Year ended December 31, 2014 revenues	$776.4	$1,368.2	$223.1	$2,367.7
Changes associated with volumes [(1)]	7.8	194.4	(68.0)	134.2
Changes associated with prices [(2)]	(315.7)	(728.6)	(75.2)	(1,119.5)
Year ended December 31, 2015 revenues	$468.5	$834.0	$79.9	$1,382.4

(1) The revenue variance attributed to the change in volume is calculated by multiplying the change in volumes from the years ended December 31, 2015 and 2014, as compared to the years ended December 31, 2014 and 2013, by the average field-level price for the years ended December 31, 2014 and 2013.

(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, 2015 and 2014, as compared to the years ended December 31, 2014 and 2013, by the respective volumes for the years ended December 31, 2014 and 2013. Pricing changes are driven by changes in commodity field-level prices, excluding the impact from commodity derivatives.

December 31, 2015 compared to December 31, 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 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 production increases in Pinedale due to continued net well completions in 2014 and 2015 and higher performing well completions from new 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 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, in which ethane is sold in the gas stream, compared to operating in ethane recovery in 2014, in which ethane is extracted from the gas stream and sold as an NGL. These production increases were mostly offset by production decreases resulting from the divestitures of non-core Midcontinent properties 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.

Oil sales. Oil sales were $834.0 million for the year ended December 31, 2015, a decrease of $534.2 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 Midcontinent due to the divestiture of non-core properties in the second and fourth quarters of 2014.

NGL Sales. NGL sales were $79.9 million for the year ended December 31, 2015, a decrease of $143.2 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, Midcontinent 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 have weakened in conjunction with the decline in crude oil prices.

December 31, 2014 compared to December 31, 2013

Gas sales. Gas sales were $776.4 million for the year ended December 31, 2014, a decrease of $2.6 million, or 0.3%, compared to 2013. This decrease was a result of 18% decrease in gas production, partially offset by higher average field-level gas prices. The decrease in production volumes was primarily driven by the continued suspension of QEP's Haynesville/Cotton Valley operated drilling program and a production decrease due to the divestiture of non-core Midcontinent properties in the second quarter of 2014. Additionally, production decreased at QEP's Pinedale field due to operating in ethane recovery in 2014, compared to operating in ethane rejection in 2013. Average field-level gas prices increased 22% in 2014 compared to 2013, driven by an increase in average NYMEX HH natural gas prices for the comparable periods.

Oil sales. Oil sales were $1,368.2 million for the year ended December 31, 2014, an increase of $451.6 million, or 49%, compared to 2013. This increase was a result of a 68% increase in oil production, partially offset by an 11% decrease in average field-level oil prices. The increase in production volumes was primarily driven by increases in the Williston Basin due to ongoing development of the properties acquired in the Williston Basin in 2012. The Company also had an additional 1,582.2 Mbbls of production in 2014 from its Permian Basin Acquisition. These volume increases were partially offset by a decrease from the divestiture of non-core Midcontinent properties at the end of the second quarter of 2014. Average field-level oil prices decreased 11% in 2014 compared to 2013, driven by a decrease in average NYMEX WTI and ICE Brent oil prices for the comparable periods.

NGL Sales. NGL sales were $223.1 million for the year ended December 31, 2014, an increase of $30.9 million, or 16%, compared to 2013. This increase was primarily a result of a 41% increase in NGL production, partially offset by an 18% decrease in average field-level NGL prices. NGL production increased by 41% from 4,811.3 Mbbl in 2013 to 6,769.1 Mbbl in 2014, due primarily to increased volumes in Pinedale and Uinta due to ethane recovery in 2014 compared to ethane rejection in 2013, while the Williston Basin NGL volumes grew as a result of increased development drilling. Additionally, the Permian Basin Acquisition contributed to the increased NGL production. These volume increases were partially offset by a decrease due to the divestiture of non-core Midcontinent properties in the second quarter of 2014. NGL prices decreased in 2014 primarily as a result of partially recovering ethane from the gas stream in Pinedale and Uinta during 2014, compared to ethane rejection in 2013. Ethane generally receives a lower per barrel price than other NGL components resulting in a lower average NGL price per barrel.

QEP Energy Resale Margin

QEP Energy purchases and resells gas in order to fulfill firm transportation contract commitments and to partially mitigate losses on unutilized capacity. The difference between the price of the products purchased and sold, net of transportation costs, creates a resale margin that represents a gain or loss for the Company. The following table is a summary of QEP Energy's financial results from its gas resale activities:

	Year Ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
Resale Margin	(in millions)				
Purchased gas sales	$86.8	$150.0	$191.6	$(63.2)	$(41.6)
Purchased gas expense	87.3	150.0	197.1	(62.7)	(47.1)
Resale margin	$(0.5)	$—	$(5.5)	$(0.5)	$5.5

During the year ended December 31, 2015, QEP Energy recorded a loss on resale margin of $0.5 million. During the year ended December 31, 2014, QEP Energy recognized no gain or loss on resale margin. During the year ended December 31, 2013, QEP Energy recorded a loss on resale margin of $5.5 million. These margins were the result of QEP Energy's purchase and sale transactions to utilize pipeline transportation commitments in Louisiana.

Operating Expenses

The following table presents certain QEP Energy operating expenses on a unit of production basis:

	Year Ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
	(per Mcfe)				
Depreciation, depletion and amortization	$2.66	$3.05	$3.09	$(0.39)	$(0.04)
Lease operating expense	0.73	0.74	0.59	(0.01)	0.15
Gas, oil and NGL transportation and other handling costs	0.92	0.90	0.78	0.02	0.12
Production and property taxes	0.35	0.63	0.51	(0.28)	0.12
Total Operating Expenses	$4.66	$5.32	$4.97	$(0.66)	$0.35

December 31, 2015 compared to December 31, 2014

Depreciation, depletion and amortization (DD&A). DD&A expense decreased $113.6 million, or $0.39 per Mcfe, 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 Midcontinent, 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 Midcontinent 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.

Lease operating expense. QEP Energy's lease operating expense (LOE) decreased $1.3 million, or $0.01 per Mcfe, during the year ended December 31, 2015 compared to 2014. The decrease was driven by a decrease in the Midcontinent 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.

Gas, oil, and NGL transportation and other handling costs. QEP Energy's gas, oil and NGL transportation and other handling costs increased $8.7 million, or $0.02 per Mcfe, during the year ended December 31, 2015, when compared to the year ended December 31, 2014. The increase in expense was primarily attributable to additional expenses incurred in Haynesville as a result of recognizing approximately $9.8 million of fees for historical 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 Midcontinent due to divestitures of non-core properties in the second and fourth quarters of 2014.

Production and property taxes. In most states in which QEP Energy 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 $88.9 million, or $0.28 per Mcfe, during 2015, primarily a result of decreased gas, oil and NGL revenues due to decreased prices and decreased NGL production volumes.

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

Impairment expense. During the year ended December 31, 2015, QEP Energy recorded impairment charges of $55.6 million, compared to $1,143.2 million of impairment charges 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 impairments on QEP's remaining Midcontinent properties, $18.4 million related to impairments in the Other Northern properties and $0.7 million related to impairments on Permian Basin properties.

December 31, 2014 compared to December 31, 2013

Depreciation, depletion and amortization. QEP Energy's DD&A expense increased $30.2 million, but decreased $0.04 per Mcfe, during the year ended December 31, 2014 when compared to 2013. The increase in DD&A expense was due to expense increases in the Williston Basin, Pinedale and related to the Permian Basin Acquisition, partially offset by expense decreases in the Midcontinent and Haynesville/Cotton Valley. The increase in the Williston Basin expense relates to increased production while the increase in Pinedale primarily relates to an increased DD&A rate. The decrease in the Midcontinent DD&A expense was a result of the second quarter 2014 property sales (see Note 2 – Acquisitions and Divestitures) while the decrease in expense in Haynesville/Cotton Valley relates to declining production.

Lease operating expense. QEP Energy's LOE increased $58.8 million, or $0.15 per Mcfe, during the year ended December 31, 2014 compared to 2013. The increase was primarily driven by the Permian Basin Acquisition oil wells in the first quarter of 2014, which in 2014 was a new operating area for QEP where we experienced higher costs, and due to increased well count and higher production from the Williston Basin oil wells, which have higher operating costs compared to other properties, which are primarily lower cost gas wells.

Gas, oil, and NGL transportation and other handling costs. QEP Energy's gas, oil and NGL transportation and other handling costs increased $49.3 million, or $0.12 per Mcfe, during the year ended December 31, 2014, due to increased production in the Williston Basin and additional expenses associated with the properties in the Permian Basin Acquisition.

Production and property taxes. In most states in which QEP Energy operates, QEP pays production taxes based on a percentage of field-level revenue, except in Louisiana, where severance taxes are volume based. Production and property taxes increased $44.2 million, or $0.12 per Mcfe, during 2014, as a result of increased oil and NGL revenues due to increased production.

Exploration expense. Exploration expense decreased $2.0 million during the year ended December 31, 2014, for QEP Energy. The decrease primarily related to lower exploration-related labor.

Impairment expense. During the year ended December 31, 2014, QEP recorded impairment charges of $1,143.2 million, compared to impairment charges of $93.0 million during 2013. Of the $1,143.2 million of impairment charges recorded during 2014, $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 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 impairments on Haynesville properties, $467.7 million related to impairments on Permian Basin properties, $18.7 million related to impairments on QEP's remaining Midcontinent properties, $13.5 million related to impairments in the Other Northern properties, $5.8 million related to impairments on Williston Basin properties, and $3.6 million related to impairments on Uinta Basin properties.

QEP MARKETING AND OTHER

QEP Marketing and Other includes the results of operations from QEP Marketing Company, including the results of a gas gathering system and an underground gas storage facility and corporate activities. The following table provides a summary of QEP Marketing and Other's financial and operating results:

	Year Ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
	(in millions)				
REVENUES					
Purchased gas and oil sales	$1,582.5	$2,360.6	$1,567.4	$(778.1)	$793.2
Other	18.8	21.7	33.8	(2.9)	(12.1)
Total Revenues	1,601.3	2,382.3	1,601.2	(781.0)	781.1
OPERATING EXPENSES					
Purchased gas and oil expense	1,588.1	2,356.6	1,570.5	(768.5)	786.1
Gathering and other expense	5.8	6.8	8.4	(1.0)	(1.6)
General and administrative	6.7	6.3	4.4	0.4	1.9
Production and property taxes	2.5	1.2	1.5	1.3	(0.3)
Depreciation, depletion and amortization	10.3	10.3	9.6	—	0.7
Total Operating Expenses	1,613.4	2,381.2	1,594.4	(767.8)	786.8
Net gains (losses) from asset sales	(5.1)	—	(0.6)	(5.1)	0.6
OPERATING INCOME (LOSS)	(17.2)	1.1	6.2	(18.3)	(5.1)
Realized gains (losses) on derivative instruments	3.8	(10.1)	(2.2)	13.9	(7.9)
Unrealized gains (losses) on derivative instruments	(0.8)	6.2	2.0	(7.0)	4.2
Interest and other income	205.7	209.7	206.9	(4.0)	2.8
Loss on extinguishment of debt	—	(2.0)	—	2.0	(2.0)
Interest expense	(145.7)	(167.5)	(167.8)	21.8	0.3
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	45.8	37.4	45.1	8.4	(7.7)
Income tax (provision) benefit	(12.3)	(14.4)	(18.6)	2.1	4.2
NET INCOME (LOSS)	$33.5	$23.0	$26.5	$10.5	$(3.5)

Resale Margin

The following table is a summary of QEP's Marketing's financial results from resale activities:

	Year Ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
	(in millions)				
Purchased gas and oil sales	$1,582.5	$2,360.6	$1,567.4	$(778.1)	$793.2
Purchased gas and oil expense	(1,588.1)	(2,356.6)	(1,570.5)	768.5	(786.1)
Realized gains (losses) on derivative instruments	3.8	(10.1)	(2.2)	13.9	(7.9)
Resale margin	$(1.8)	$(6.1)	$(5.3)	$4.3	$(0.8)

Purchased gas and oil sales decreased by $778.1 million, or 33%, during the year ended December 31, 2015 compared to 2014, due to a $568.5 million decrease in resale oil sales and a $209.4 million decrease in resale gas sales. Resale oil sales decreased due to a 48% decrease in resale oil price, partially offset by a 28% increase in the resale oil volumes. Resale gas sales decreased due to a 41% decrease in resale price, partially offset by a 13% increase in resale volumes.

During the year ended December 31, 2015, purchased gas and oil expense, which includes transportation expense, decreased $768.5 million, or 33%, compared to the year ended December 31, 2014, due to a $566.5 million decrease in resale oil purchases and a $202.0 million decrease in resale gas purchases. Resale oil purchases decreased due to a 48% decrease in resale purchase price, partially offset by a 26% increase in resale purchase volumes. Resale gas purchases decreased due to a 38% decrease in the resale purchase price, partially offset by 10% increase in resale purchase volumes.

During the year ended December 31, 2014, purchased gas and oil sales increased by $793.2 million, or 51%, compared to the year ended December 31, 2013, due to a $765.4 million increase in resale oil sales and a $27.8 million increase in resale gas sales. Resale oil sales increased due to a 107% increase in the resale oil volumes, partially offset by a 14% decrease in resale oil price. Resale gas sales increased due to a 47% increase in resale price, partially offset by a 29% decrease in resale volumes.

During the year ended December 31, 2014, purchased gas and oil expense, which includes transportation expense, increased 50%, compared to the year ended December 31, 2013, due to a $765.0 million increase in resale oil purchases and a $21.1 million increase in resale gas purchases. Resale oil purchases increased due to a 108% increase in the resale purchase volumes, partially offset by a 12% decrease in resale purchase price. Resale gas purchases increased due to a 21% increase in the resale purchase price, partially offset by a 13% decrease in resale purchase gas volumes.

See Note 1 – Summary of Significant Accounting Policies in Item 8 of Part II of this Annual Report on Form 10-K for additional discussion regarding the reporting of certain purchased oil transactions.

QEP RESOURCES

Other Consolidated Expenses and Income from Continuing and Discontinued Operations

December 31, 2015 compared to December 31, 2014

General and administrative expense. During 2015, general and administrative (G&A) expense decreased $23.3 million, or 11%, compared to 2014. The decrease in G&A 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 (ERP) 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 changes 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 is 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 in post-closing adjustments related to 2014 divestitures.

Realized and unrealized gains (losses) on derivative contracts. Gains and losses on derivative instruments are comprised of both realized and unrealized gains and losses on QEP's commodity derivative contracts and interest rate swaps, which are marked-to-market each month. During the year ended December 31, 2015, gains on commodity derivative instruments were $277.2 million, of which $460.9 million was 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 in 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 is 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 taxes. 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 the unrecognized tax benefit (see Note 13 – Income Taxes for additional information).

December 31, 2014 compared to December 31, 2013

General and administrative expense. During 2014, G&A expense increased $44.0 million, or 27%, compared to 2013. The increase in G&A in 2014 compared to 2013, was primarily due to the following: a $22.7 million increase in labor and benefits associated with increases in the number of employees before completion of the Midstream Sale and the Company's annual compensation program and an $11.1 million increase in professional and outside services and compensation expense mainly related to the ERP system implementation.

Net gain (loss) from asset sales. During the year ended December 31, 2014, QEP recognized a loss on sale of assets of $148.6 million, compared to a gain on sale of $103.5 million during the year ended December 31, 2013. The loss on sale of assets recognized in 2014 is primarily due to QEP Energy's divestitures of the majority of the Company's Midcontinent properties in the second and fourth quarters of 2014 for a pre-tax loss on sale of $146.1 million.

Realized and unrealized gains (losses) on derivative contracts. Gains and losses on derivative instruments are comprised of both realized and unrealized gains and losses on QEP's commodity derivative contracts and interest rate swaps, which are marked-to-market each month. During the year ended December 31, 2014, gains on commodity derivative instruments were $368.9 million, of which $3.5 million were realized losses and $372.4 million were unrealized gains. Additionally, during the year ended December 31, 2014, losses from interest rate swaps were $5.6 million, of which $7.6 million were realized losses partially offset by $2.0 million in unrealized gains. During 2013, gains on commodity derivative instruments were $57.5 million, of which $150.3 million were realized gains partially offset by $92.8 million in unrealized losses. Additionally, during 2013, gains from interest rate swaps were $1.4 million, of which $4.1 million were unrealized gains partially offset by $2.7 million in realized losses.

Interest expense. Interest expense increased $4.0 million, or 2%, during the year ended December 31, 2014 compared to 2013, due to higher average debt levels in 2014. The increase in debt levels in 2014 was primarily related to additional borrowing on the credit facility and an increase in QEP's term loan to $600.0 million in the first quarter of 2014, both of which were used to fund the Permian Basin Acquisition. In December 2014, QEP repaid and terminated the $600.0 million term loan and repaid the entire outstanding balance on the credit facility with a portion of the proceeds from the Midstream Sale.

Income taxes. Income tax provision decreased $292.6 million during the year ended December 31, 2014 compared to 2013. The decrease was the result of lower income before income taxes and a lower combined effective federal and state income tax rate of 36.2% during the year ended December 31, 2014, compared to 53.6% for the year ended December 31, 2013. The 2013 combined effective rate was higher due to the impairment of goodwill of $59.5 million that is non-deductible for tax purposes.

Discontinued Operations. Discontinued operations represent results of operations from QEP Field Services, excluding the results of Haynesville Gathering, which was added to the QEP Marketing and Other segment. During the year ended December 31, 2014, net income from discontinued operations was $1,193.9 million, which includes a $1,793.4 million gain on sale. Excluding the gain on sale, income before taxes from discontinued operations decreased $48.7 million during the year ended December 31, 2014 compared to 2013. This decrease was primarily due to only having 11 months of activity in 2014 compared to a full year of activity in 2013 and an 8% decrease in QEP Field Services' keep-whole margin during the year ended December 31, 2014. The decrease in keep-whole margin was due to an increase in transportation and shrink expenses primarily related to higher natural gas prices, partially offset by a 7% increase in NGL sales due to a 20% increase in the average net realized NGL sales price. The increase in the NGL sales price was a result of higher propane prices in the first half of 2014 compared to the first half of 2013 and the completion of the Blacks Fork fractionation and loading facility expansion in late 2013, which gave QEP Field Services the ability to sell products into local and regional markets.

LIQUIDITY AND CAPITAL RESOURCES

QEP plans to fund its development projects by employing a capital structure and financing strategy that will provide sufficient liquidity to withstand commodity price volatility. As a part of this strategy, QEP maintains a commodity price derivative strategy to reduce the financial impact of commodity price volatility and to provide some certainty to its cash flows. In response to the current commodity price environment, we have reduced drilling and completion activity, slowed production growth and preserved liquidity and plan to continue these strategies in 2016. Additionally, in February 2016, the Board of Directors indefinitely suspended the payment of quarterly dividends.

Generally, QEP funds its operations, capital expenditures and working capital requirements with cash flow from its operating activities and borrowings under its revolving credit facility. To provide additional liquidity, QEP also periodically accesses debt markets and sells non-core assets. In 2015, we filed an automatic shelf registration statement on Form S-3 with the SEC, pursuant to which we may offer and sell debt securities and common stock from time to time. The Company expects cash flow from operations, cash on hand and availability under its credit facility will be sufficient to fund the Company’s planned capital expenditures, operating expenses and repayment of maturing debt during the next 12 months and the foreseeable future. To the extent actual operating results or actual commodity prices differ from the Company’s assumptions, QEP's liquidity could be adversely affected.

The following table provides QEP’s available liquidity and debt to equity ratio compared to the previous period:

	December 31,	
	2015	2014
	(in millions, except %)	
Cash and cash equivalents	$376.1	$1,160.1
Amount available under the QEP credit facility [1]	1,796.6	1,796.3
Total liquidity	$2,172.7	$2,956.4
Total debt	$2,218.8	$2,218.1
Total common shareholders' equity	3,947.9	4,075.3
Ratio of debt to total capital [2]	36 %	35 %

(1) See discussion of revolving credit facility below. Availability under the QEP credit facility is reduced by outstanding letters of credit of $3.4 million and $3.7 million as of December 31, 2015 and 2014, respectively.
(2) Defined as total debt divided by the sum of total debt plus common shareholders’ equity.

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 (as defined in the credit agreement) that limit the amount of debt the Company can incur which includes: (i) a net funded debt to capitalization ratio than 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. The present value coverage ratio covenant became effective in February 2016, following the Moody's rating downgrade of QEP's credit rating from Ba1 to B1.

During the year ended December 31, 2014, QEP's weighted-average interest rate on borrowings from its credit facility was 2.23%. At December 31, 2015 and 2014, QEP had no borrowings outstanding and had $3.4 million and $3.7 million, respectively, in letters of credit outstanding under the credit facility and was in compliance with the covenants under the credit agreement. At February 19, 2016, QEP had no borrowings outstanding, had $3.4 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 unsecured notes outstanding as of December 31, 2015, totaled $2,221.8 million principal amount and are comprised of six issuances as follows:

- $176.8 million 6.05% Senior Notes due September 2016;
- $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.

Depending on market conditions and prices, contractual restrictions, our financial liquidity and other factors, we may from time to time seek to repurchase our senior notes through open market purchases, privately negotiated purchases, tender offers and redemptions. The amounts involved in any such transactions, individually or in the aggregate, may be material.

Cash Flow from Operating Activities

Cash flows from operating activities are primarily affected by gas, oil 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 gas, oil and NGL production for the next 12 to 36 months.

Net cash provided from operating activities is presented below:

	Year Ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
	(in millions)				
Net income (loss)	$(149.4)	$784.4	$159.4	$(933.8)	$625.0
Net income attributable to noncontrolling interest	—	21.6	12.0	(21.6)	9.6
Non-cash adjustments to net income	1,193.4	123.0	1,196.4	1,070.4	(1,073.4)
Changes in operating assets and liabilities	(562.7)	613.5	(176.1)	(1,176.2)	789.6
Net cash provided from operating activities	$481.3	$1,542.5	$1,191.7	$(1,061.2)	$350.8

Net cash provided by operating activities during the year ended December 31, 2015, decreased $1,061.2 million compared to 2014, due to a decrease in changes in operating assets and liabilities and a net loss incurred in 2015 compared to net income in 2014, partially offset by larger non-cash adjustments to net income in 2015. Changes in operating assets and liabilities decreased $1,176.2 million during the year ended December 31, 2015, due to a decrease in income taxes payable of $1,113.5 million, primarily related to taxes paid on the gain on the Midstream Sale, which were paid in 2015, and a decrease of $391.4 million in accounts payable and accrued expenses, partially offset by an increase in accounts receivable of $326.0 million, both of which were primarily related to timing of payments and receipts. Non-cash adjustments to net income increased $1,070.4 million, primarily due to the net gain from asset sales in 2014 related to the Midstream Sale and unrealized losses on derivative contracts during 2015 of $183.7 million compared to $374.4 million of unrealized gains on derivatives contracts in 2014. These increases were partially offset by a decrease in impairment expense of $1,087.6 million in 2015 and a decrease in depreciation, depletion, and amortization of $159.5 million.

Net cash provided by operating activities during the year ended December 31, 2014, increased $350.8 million compared to 2013, due to an increase in net income and changes in operating assets and liabilities, partially offset by non-cash adjustments to net income. Changes in operating assets and liabilities increased $789.6 million during the year ended December 31, 2014, mainly due to a $521.5 million increase in income taxes payable primarily related to the recognition of the gain on the Midstream Sale and an increase of $499.8 million in accounts payable and accrued expenses partially offset by a decrease in accounts receivable of $163.7 million both of which were primarily related to timing of payments and receipts. Non-cash adjustments to net income decreased $1,073.4 million due to the $1,793.4 million gain on the Midstream Sale and unrealized gains on derivative contracts during 2014 of $374.4 million compared to $88.7 million of losses in 2013, which were partially offset by a $1,050.2 million increase in impairment expense during 2014.

Cash Flow from Investing Activities

A comparison of capital expenditures for the years ended December 31, 2015, 2014 and 2013, and a forecast for the calendar year 2016 are presented in the table below:

	2016	Year Ended December 31,			Change	
	Forecast[1]	2015	2014	2013	2015 vs 2014	2014 vs 2013
	(in millions)					
QEP Energy	$475.0	$1,105.7	$2,670.5	$1,467.2	$(1,564.8)	$1,203.3
QEP Marketing and Other	—	4.5	13.6	24.6	(9.1)	(11.0)
Continuing Operations	475.0	1,110.2	2,684.1	1,491.8	(1,573.9)	1,192.3
Discontinued Operations	—	—	50.7	85.6	(50.7)	(34.9)
Total accrued capital expenditures	475.0	1,110.2	2,734.8	1,577.4	(1,624.6)	1,157.4
Change in accruals	—	129.2	(8.4)	25.2	137.6	(33.6)
Total cash capital expenditures	$475.0	$1,239.4	$2,726.4	$1,602.6	$(1,487.0)	$1,123.8

[1] Represents the mid-point of QEP's most recent guidance.

During the year ended December 31, 2015, on an accrual basis, the Company invested $1,011.9 million on property, plant and equipment capital 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 Uinta, $3.7 million in Other Northern, $3.4 million in the Midcontinent and $36.9 million in Haynesville/Cotton Valley. 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's 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 Midcontinent and Other Northern areas.

During the year ended December 31, 2014, on an accrual basis, the Company invested $1,723.6 million on property, plant and equipment expenditures, excluding property acquisitions, for continuing operations, an increase of $272.7 million compared to 2013. 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 Uinta, $42.9 million in Other Northern, $41.3 million in the Midcontinent and $50.3 million in Haynesville/Cotton Valley. In addition, during the year ended December 31, 2014, the Company had cash inflows of $3.3 billion from the Midstream Sale and other sales of non-core oil and gas properties, which were partially offset by $960.5 million of property acquisitions, primarily relating to the Permian Basin Acquisition.

In response to the current commodity price environment, QEP intends to significantly reduce its capital budget for drilling and completions from 2015 activity. Due to efficiency gains, strong well performance, and ongoing cost initiatives, QEP expects to see flat or only slightly lower oil production in 2016. The mid-point of our forecasted capital expenditures (excluding property acquisitions) for 2016 is $475.0 million. QEP intends to fund capital expenditures with cash flow from operating activities, cash on hand, and, if needed, borrowings under its credit facility. The aggregate levels of capital expenditures for 2016 and the allocation of those expenditures are dependent on a variety of factors, including drilling results, gas, oil 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, 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 the checks outstanding in excess of cash balances of $24.9 million and paid long-term debt issuance costs of $2.6 million. Additionally, during the year ended December 31, 2015, the Company made dividend payments of $14.1 million. As of December 31, 2015, long-term debt consisted of $2,221.8 million in senior notes (excluding $3.0 million of net original issue discount).

During the year ended December 31, 2014, net cash used in financing activities was $990.6 million compared to net cash provided by financing activities of $279.8 million during the year ended December 31, 2013. During the year ended December 31, 2014, QEP had borrowings from the credit facility of $5,455.0 million and borrowings under the term loan of $300.0 million, which were used to fund the Permian Basin Acquisition and operating activities throughout the year. During the year ended December 31, 2014, QEP made repayments on its 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. Additionally, during the year ended December 31, 2014, there was a decrease in the 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. At December 31, 2014, long-term debt consisted of $2,221.8 million in senior notes (excluding $3.7 million of net original issue discount).

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, 2015, the Company's material off-balance sheet arrangements and transactions included operating lease arrangements, drilling and transportation contracts and undrawn letters of credit. There are no other transactions, arrangements, or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect QEP's liquidity or availability of, or requirements for capital resources. See "Contractual Cash Obligations and Other Commitments" below for more information regarding 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, 2015:

	Payments Due by Year [1]						
	Total	2016	2017	2018	2019	2020	After 2020
	(in millions)						
Long-term debt	$2,221.8	$176.8	$—	$134.0	$—	$136.0	$1,775.0
Interest on fixed-rate, long-term debt [2]	719.7	129.4	122.3	115.5	113.2	105.5	133.8
Drilling contracts	10.3	10.3	—	—	—	—	—
Gathering, processing, firm transportation and storage [3]	809.1	116.1	129.4	111.8	105.0	87.8	259.0
Asset retirement obligations [4]	206.8	1.8	5.9	6.2	5.9	4.1	182.9
Operating leases	61.6	9.7	9.8	8.5	7.6	7.4	18.6
Total	$4,029.3	$444.1	$267.4	$376.0	$231.7	$340.8	$2,369.3

(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 credit facility.

(3) Includes firm transportation rates that are subject to FERC approval and may change as a result of the outcome of pending approvals.

(4) 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. In the context of oil field goods and services, the Company experienced significant inflation during the years ended December 31, 2013 and 2014, and significant deflation during the year ended December 31, 2015. 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. 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. While QEP does not presently expect business costs to materially rise during 2016 and in the near term, higher prices for oil and gas could result in increases in the costs of materials, services and 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 our financial statements.

Oil and Gas Reserves

One of the most significant estimates the Company makes is the estimate of gas, oil and NGL reserves. Gas, oil 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 and gas 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 Energy engages independent reservoir engineering consultants to prepare estimates of the proved oil and gas 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 16 – Supplemental Oil and Gas Information (unaudited), in Item 8 of Part II of this Annual Report on Form 10-K.

Successful Efforts Accounting for Oil and Gas Operations

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

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 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, an impairment of oil and gas reserves caused by mechanical problems, faster-than-expected decline of reserves, lease ownership issues and declines in gas, oil 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, 2015, 2014 and 2013, QEP recorded impairment charges of $39.3 million, $1,041.4 million and $1.2 million, respectively, on some of its higher cost, proved properties in both of its Northern and Southern regions. The 2014 and 2015 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, 2015, 2014 and 2013, QEP recorded impairment charges of $2.0 million, $101.8 million and $32.3 million respectively, on its unproved properties.

Asset Retirement Obligations

QEP records asset retirement obligations (ARO) when the asset is placed in service and there are legal obligations 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. 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 obligation discounted at QEP's credit-adjusted risk-free interest rate. ARO is subject to revisions because of the intrinsic uncertainties present when estimating asset retirement costs and asset retirement settlement dates. ARO revisions can result from changes in expected cash flows or material changes in estimated asset retirement costs. QEP's ARO liability at December 31, 2015, 2014 and 2013, was $206.8 million, $195.1 million and $165.1 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 Energy recognizes revenue in the period that services are provided or products are delivered. Revenues associated with the sale of gas, oil and NGL are accounted for using the sales method, whereby revenue is recognized as gas, oil 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 Energy has sold volumes in excess of its share of remaining reserves in an underlying property.

QEP Marketing reports revenues gross in accordance with principal-agent considerations. QEP Marketing markets affiliate and third-party gas, oil and NGL volumes. QEP Marketing uses derivatives to secure a known price for a specific volume over a specific time period. QEP Marketing 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.

Litigation and Other Contingencies
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. Because legal proceedings are inherently unpredictable and unfavorable resolutions can occur, assessing contingencies is highly subjective and requires judgments about future events. When evaluating contingencies, QEP may be unable to provide a meaningful estimate due to a number of factors, including the procedural status of the matter in question, the presence of complex or novel legal theories, or the ongoing discovery and development of information important to the matter. QEP regularly reviews contingencies to determine the adequacy of its accruals and related disclosures. The amount of ultimate loss may differ from these estimates. 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 charged to expense 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 QEP'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 derivative contracts, 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 recognize 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. 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 plans, including both a qualified and a supplemental plan. QEP also provides certain health care and life insurance benefits for certain retired employees. Determination of the benefit obligations for QEP's defined-benefit pension and postretirement 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 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 and restricted shares 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 granting of restricted shares results in the recognition of compensation cost measured at the grant-date market price. QEP uses an accelerated method in recognizing share-based compensation costs 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 shares vest in equal installments over a specified number of years after the grant date with the majority vesting in three years. Non-vested restricted shares have voting and dividend rights; however, sale or transfer is restricted. The Company also awards performance share units under its Cash Incentive Plan (CIP) that are generally paid out in cash depending upon the Company's total shareholder return compared to a group of its peers over a three-year period. The performance share unit's compensation cost is equal to its fair value as of the period end 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 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 gain on bargain purchase or goodwill. The amount of goodwill or gain on bargain purchase 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 prepares estimates of gas, oil and NGL reserves. QEP estimates future prices to apply to the estimated reserves quantities acquired and estimates future operating and development costs to arrive at estimates of future net cash flows. For estimated proved reserves, 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 gas, oil 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 also 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, an 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 sustained, significant decline. Furthermore, the Company’s credit facility has a floating interest rate which exposes QEP to interest rate risk. To 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 interest rate swaps to manage interest rate risk.

Commodity Price Risk Management

QEP uses commodity price 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 derivative instruments utilized by the Company do not have margin requirements or collateral provisions that would require payments prior to the scheduled cash settlement dates. As of December 31, 2015, QEP held commodity price derivative contracts totaling 225.6 million MMBtu of gas and 9.2 million barrels of oil. At December 31, 2014, the QEP derivative contracts covered 74.0 million MMBtu of gas and 9.1 million barrels of oil.

The following table presents QEP's derivative positions as of February 19, 2016. 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, 2015.

QEP Energy Commodity Derivative Swap Positions

Year	Index	Total Volumes (in millions)	Average Swap Price per Unit
Gas sales		(MMBtu)	
2016	NYMEX HH	46.5	$2.80
2016	IFNPCR	61.2	$2.53
2017	NYMEX HH	65.7	$2.76
2017	IFNPCR	25.6	$2.53
2018	NYMEX HH	7.3	$2.80
Oil sales		(Bbls)	
2016	NYMEX WTI	6.7	$55.84
2017	NYMEX WTI	2.6	$54.39

QEP Energy Gas Collars

Year	Index	Total Volume	Average Price Floor	Average Price Ceiling
		(in millions) (MMBtu)	($/MMBtu)	($/MMBtu)
2016	NYMEX HH	6.1	$2.75	$3.89

QEP Energy Gas Sales Basis Swaps

Year	Index Less Differential	Index	Total Volumes MMBtu (in millions)	Weighted-Average Differential
Gas basis swaps			(MMBtu)	($/MMBtu)
2016	NYMEX HH	IFNPCR	30.6	$(0.16)
2017	NYMEX HH	IFNPCR	32.9	$(0.19)

QEP Marketing Commodity Derivative Positions

Year	Type of Contract	Index	Total Volumes (in millions)	Average Swap Price per MMBtu
Gas sales			(MMBtu)	
2016	SWAP	IFNPCR	3.2	$2.68
2017	SWAP	IFNPCR	0.1	$2.71
Gas purchases			(MMBtu)	
2016	SWAP	IFNPCR	0.2	$1.83

Changes in the fair value of derivative contracts from December 31, 2014 to December 31, 2015, are presented below:

	Commodity derivative contracts
	(in millions)
Net fair value of gas and oil derivative contracts outstanding at December 31, 2014	$348.9
Contracts settled	(460.9)
Change in oil and gas prices on futures markets	99.4
Contracts added	177.8
Net fair value of oil and gas derivative contracts outstanding at December 31, 2015	$165.2

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

	December 31, 2015
	(in millions)
Net fair value – asset (liability)	$165.2
Fair value if market prices of oil and gas and basis differentials decline by 10%	181.7
Fair value if market prices of oil and gas and basis differentials increase by 10%	148.7

Utilizing the actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these instruments by $16.5 million, while a 10% decrease in underlying commodity prices would increase the fair value of these instruments by $16.5 million as of December 31, 2015. 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 as described in the Risk Factors, in Item 1A of Part I of this Annual Report on Form 10-K. The Company's credit facility has a floating interest rate, which exposes QEP to interest rate risk. At December 31, 2015 and December 31, 2014, the Company did not have any borrowings outstanding under its credit facility.

The remaining $2,221.8 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 other schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or Notes thereto.

Report of Independent Registered Public Accounting Firm

To 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, equity and cash flows present fairly, in all material respects, the financial position QEP Resources, Inc. at December 31, 2015 and December 31, 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule for each of the three years ended December 31, 2015, appearing under Item 15(c) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, 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 and financial statement schedule, 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, on the financial statement schedule, 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.
As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for the presentation of deferred income taxes in 2015.
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 24, 2016

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2015	2014	2013
REVENUES	(in millions, except per share amounts)		
Gas sales	$468.5	$776.4	$779.0
Oil sales	834.2	1,368.5	916.6
NGL sales	80.0	223.3	192.2
Other revenues	15.1	11.1	22.4
Purchased gas and oil sales	620.8	913.9	774.9
Total Revenues	2,018.6	3,293.2	2,685.1
OPERATING EXPENSES			
Purchased gas and oil expense	626.8	910.1	783.5
Lease operating expense	238.8	240.1	181.3
Gas, oil and NGL transportation and other handling costs	291.3	277.6	222.0
Gathering and other expense	5.8	6.7	8.4
General and administrative	181.1	204.4	160.4
Production and property taxes	117.6	205.2	161.3
Depreciation, depletion and amortization	881.1	994.7	963.8
Exploration expenses	2.7	9.9	11.9
Impairment	55.6	1,143.2	93.0
Total Operating Expenses	2,400.8	3,991.9	2,585.6
Net gain (loss) from asset sales	4.6	(148.6)	103.5
OPERATING INCOME (LOSS)	(377.6)	(847.3)	203.0
Realized and unrealized gains (losses) on derivative contracts (Note 7)	277.2	363.3	58.9
Interest and other income	3.0	12.8	15.2
Income from unconsolidated affiliates	—	0.3	0.2
Loss from early extinguishment of debt	—	(2.0)	—
Interest expense	(145.6)	(169.1)	(165.1)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(243.0)	(642.0)	112.2
Income tax (provision) benefit	93.6	232.5	(60.1)
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	(149.4)	(409.5)	52.1
Net income from discontinued operations, net of income tax	—	1,193.9	107.3
NET INCOME (LOSS)	$(149.4)	$784.4	$159.4
Earnings (loss) per common share			
Basic from continuing operations	$(0.85)	$(2.28)	$0.29
Basic from discontinued operations	—	6.64	0.60
Basic total	$(0.85)	$4.36	$0.89
Diluted from continuing operations	$(0.85)	$(2.28)	$0.29
Diluted from discontinued operations	—	6.64	0.60
Diluted total	$(0.85)	$4.36	$0.89
Weighted-average common shares outstanding			
Used in basic calculation	176.6	179.8	179.2
Used in diluted calculation	176.6	179.8	179.5
Dividends per common share	$0.08	$0.08	$0.08

See Notes accompanying the Consolidated Financial Statements.

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

	Year Ended December 31,		
	2015	2014	2013
	(in millions)		
Net income (loss)	$(149.4)	$784.4	$159.4
Other comprehensive (loss) income, net of tax:			
Reclassification of previously deferred derivative losses[1]	—	—	(77.6)
Pension and other postretirement plans adjustments:			
Current year net actuarial gain (loss) [2]	(0.5)	(13.6)	13.5
Amortization of net actuarial loss [3]	0.3	0.5	1.5
Amortization of prior service cost [4]	8.2	9.7	3.3
Current year prior service cost [5]	(0.6)	—	—
Net curtailment and settlement cost incurred [6]	4.5	5.6	—
Total pension and other postretirement plan adjustments	11.9	2.2	18.3
Other comprehensive income (loss)	11.9	2.2	(59.3)
Comprehensive income (loss)	$(137.5)	$786.6	$100.1

(1) Presented net of income tax benefit of $45.9 million for the year ended December 31, 2013.

(2) Presented net of income tax benefit of $0.3 million for the year ended December 31, 2015, net of income tax benefit of $8.5 million for the year ended December 31, 2014, and net of income tax expense of $8.3 million for the year ended December 31, 2013.

(3) Presented net of income tax expense of $0.2 million, $0.3 million, and $0.9 million during the years ended December 31, 2015, 2014, and 2013, respectively.

(4) Presented net of income tax expense of $4.9 million, $6.0 million, and $2.1 million during the years ended December 31, 2015, 2014, and 2013, respectively.

(5) Presented net of income tax benefit of $0.3 million for the year ended December 31, 2015.

(6) 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, 2015	December 31, 2014
ASSETS	(in millions)	
Current Assets		
Cash and cash equivalents	$376.1	$1,160.1
Accounts receivable, net	278.2	441.9
Income tax receivable	87.3	—
Fair value of derivative contracts	146.8	339.0
Gas, oil and NGL inventories, at lower of average cost or market	13.3	13.7
Prepaid expenses and other	30.1	46.8
Total Current Assets	931.8	2,001.5
Property, Plant and Equipment (successful efforts method for oil and gas properties)		
Proved properties	13,314.9	12,278.7
Unproved properties	691.0	825.2
Marketing and other	297.9	293.8
Materials and supplies	38.5	54.3
Total Property, Plant and Equipment	14,342.3	13,452.0
Less Accumulated Depreciation, Depletion and Amortization		
Exploration and production	6,870.2	6,153.0
Marketing and other	87.5	67.8
Total Accumulated Depreciation, Depletion and Amortization	6,957.7	6,220.8
Net Property, Plant and Equipment	7,384.6	7,231.2
Fair value of derivative contracts	23.2	9.9
Other noncurrent assets	85.9	44.2
TOTAL ASSETS	$8,425.5	$9,286.8
LIABILITIES AND EQUITY		
Current Liabilities		
Checks outstanding in excess of cash balances	$29.8	$54.7
Accounts payable and accrued expenses	351.7	575.4
Income taxes payable	—	532.1
Production and property taxes	46.1	61.7
Interest payable	36.4	36.4
Fair value of derivative contracts	0.8	—
Deferred income taxes	—	84.5
Current portion of long-term debt	176.8	—
Total Current Liabilities	641.6	1,344.8
Long-term debt	2,042.0	2,218.1
Deferred income taxes	1,479.8	1,362.7
Asset retirement obligations	204.9	193.8
Fair value of derivative contracts	4.0	—
Other long-term liabilities	105.3	92.1
Commitments and Contingencies (Note 10)		
EQUITY		
Common stock - par value $0.01 per share; 500.0 million shares authorized; 177.3 million and 176.2 million shares issued, respectively	1.8	1.8
Treasury stock - 0.5 million and 0.8 million shares, respectively	(14.6)	(25.4)

Additional paid-in capital	554.8	535.3
Retained earnings	3,418.3	3,587.9
Accumulated other comprehensive income (loss)	(12.4)	(24.3)
Total Common Shareholders' Equity	3,947.9	4,075.3
TOTAL LIABILITIES AND EQUITY	$8,425.5	$9,286.8

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, 2012	178.5	$ 1.8	(0.1)	$ (3.7)	$ 462.1	$ 2,773.0	$ 32.8	$ 47.7	$ 3,313.7
Net income (loss)	—	—	—	—	—	159.4	—	12.0	171.4
Dividends paid	—	—	—	—	—	(14.3)	—	—	(14.3)
Share-based compensation	1.2	—	(0.3)	(11.2)	36.3	(0.3)	—	0.2	25.0
Distribution of noncontrolling interest	—	—	—	—	—	—	—	(9.3)	(9.3)
Net proceeds from QEP Midstream initial public offering	—	—	—	—	—	—	—	449.6	449.6
Reclassification of previously deferred derivative gains in OCI, net of tax	—	—	—	—	—	—	(77.6)	—	(77.6)
Change in pension and postretirement liability, net of tax	—	—	—	—	—	—	18.3	—	18.3
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 Midstream Sale	—	—	—	—	—	—	—	(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

See Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2015	2014	2013
OPERATING ACTIVITIES	(in millions)		
Net income (loss)	$(149.4)	$784.4	$159.4
Net income attributable to noncontrolling interest	—	21.6	12.0
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	881.1	1,040.6	1,016.0
Deferred income taxes	25.3	(84.1)	66.1
Impairment	55.6	1,143.2	93.0
Share-based compensation	34.7	27.2	27.1
Pension curtailment	11.2	—	—
Amortization of debt issuance costs and discounts	6.2	6.7	6.4
Net loss (gain) from asset sales	(4.6)	(1,644.8)	(103.0)
Income from unconsolidated affiliates	—	(5.2)	(5.8)
Distributions from unconsolidated affiliates and other	—	9.4	7.9
Non-cash loss on early extinguishment of debt	—	4.4	—
Unrealized (gains) losses on marketable securities	0.2	—	—
Unrealized (gains) losses on derivative contracts	183.7	(374.4)	88.7
Changes in operating assets and liabilities			
Accounts receivable	165.5	(160.5)	3.2
Inventories	15.5	(20.2)	2.6
Prepaid expenses	16.7	(7.3)	14.0
Accounts payable and accrued expenses	(71.3)	320.1	(179.7)
Federal income taxes	(619.4)	494.1	(27.4)
Other	(69.7)	(12.7)	11.2
Net Cash Provided by Operating Activities	481.3	1,542.5	1,191.7
INVESTING ACTIVITIES			
Property acquisitions	(98.3)	(960.5)	(40.9)
Property, plant and equipment, including dry hole exploratory well expense	(1,141.1)	(1,765.9)	(1,561.7)
Proceeds from disposition of assets	21.8	3,296.6	211.1
Acquisition deposit held in escrow	—	50.0	(50.0)
Other investing activities	—	(42.0)	—
Net Cash Provided by (Used in) Investing Activities	(1,217.6)	578.2	(1,441.5)
FINANCING ACTIVITIES			
Checks outstanding in excess of cash balances	(24.9)	(54.4)	69.3
Long-term debt issued	—	300.0	—
Long-term debt issuance costs paid	(2.6)	(9.3)	(3.2)
Long-term debt repaid	—	(600.0)	—
Proceeds from credit facility	—	5,455.0	3,085.0
Repayments of credit facility	—	(5,935.0)	(3,295.0)
Common stock repurchased and retired	—	(99.7)	—
Treasury stock repurchases	(2.7)	(6.2)	(9.3)
Other capital contributions	(0.2)	6.0	7.0
Dividends paid	(14.1)	(14.6)	(14.3)
Excess tax (provision) benefit on share-based compensation	(3.2)	(0.5)	—
Net proceeds from the issuance of common units	—	—	449.6

Distribution to noncontrolling interest	—	(31.9)	(9.3)
Net Cash Provided by (Used in) Financing Activities	(47.7)	(990.6)	279.8
Change in cash and cash equivalents	(784.0)	1,130.1	30.0
Beginning cash and cash equivalents	1,160.1	30.0	—
Ending cash and cash equivalents	$376.1	$1,160.1	$30.0

See Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
NOTES ACCOMPANYING THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 – Summary of Significant Accounting Policies

Nature of Business

QEP Resources, Inc. (QEP or the Company) is a holding company with two principal subsidiaries, QEP Energy Company and QEP Marketing Company, which are engaged in two primary lines of business: (i) oil and gas exploration and production (QEP Energy) and (ii) oil and gas marketing, operation of a gas gathering system and an underground gas storage facility and corporate activities (QEP Marketing and Other).

QEP's operations are focused in two geographic regions: the Northern Region (primarily in Wyoming, North Dakota and Utah) and the Southern Region (primarily in Texas and Louisiana) of the United States. QEP's corporate headquarters are located in Denver, Colorado.

Shares of QEP's common stock trade on the New York Stock Exchange 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.

Revision of Financial Statements

In the fourth quarter of 2015, the Company determined that certain transactions that had been reported on a gross basis and included in "Purchased gas and oil sales" and "Purchased gas and oil expense" on the Consolidated Statement of Operations for certain periods in 2014 and the first three quarters of 2015 should have been reported net, as the transactions were with the same counterparty and were entered into in contemplation of one another. The Company revised its financial statements to reflect the net accounting treatment and assessed the cumulative impact of the revisions on each period affected. The revisions had no effect on the Company's operating income, net income, earnings per share or cash flows. The Company determined that the impact of the change from gross to net accounting was not material, either individually or in the aggregate, to previously issued financial statements. The Company has, however, recast its Consolidated Statement of Operations for the year ended December 31, 2014, to report “Purchased gas and oil sales” and “Purchased gas and oil expense” on a net basis to conform to presentation for the year ended December 31, 2015.

The following table details the impact of these revisions for the year ended December 31, 2014, on the Consolidated Statement of Operations.

	Year Ended December 31, 2014		
	As reported	As revised	Change
	(in millions)		
REVENUES			
Purchased gas and oil sales	$1,035.0	$913.9	$(121.1)
Total Revenues	3,414.3	3,293.2	(121.1)
OPERATING EXPENSES			
Purchased gas and oil expense	$1,031.2	$910.1	$(121.1)
Total Operating Expenses	4,113.0	3,991.9	(121.1)

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 gas, oil 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 gas, oil and NGL, each of which depends on numerous factors beyond the Company’s control such as economic conditions, regulatory developments, global supply and demand and competition from other energy sources. The energy markets historically have been volatile. Oil and gas prices throughout 2015 and in early 2016 have been substantially lower than historical averages. Prices will 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. In response to the current commodity price environment, we have reduced drilling and completion activity, slowed production growth and preserved liquidity and plan to continue these strategies in 2016.
The Company utilizes cash on hand, availability under its credit facility and cash flows from operating activities to fund its capital expenditures. Based on its current cash on hand, expected cash flow from operations and availability under its credit facility, the Company expects to be able to fund its planned capital expenditures, operating expenses and repayment of maturing debt 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 the 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

Revenues are recognized in the period that services are provided or products are delivered. Revenues associated with the sale of gas, oil and NGL are accounted for using the sales method, whereby revenue is recognized as gas, oil and NGL is 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 Energy has sold volumes in excess of its share of remaining reserves in an underlying property. QEP's imbalance obligations at December 31, 2015 and 2014, were $3.5 million and $7.9 million, respectively.

QEP Marketing reports revenues gross in accordance with principal-agent considerations. QEP Marketing markets affiliate and third-party gas, oil and NGL volumes. QEP Marketing uses derivatives to secure a known price for a specific volume over a specific time period. QEP Marketing 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.

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, 2015, QEP had unrestricted cash of $376.1 million. In addition, QEP had restricted cash of $18.1 million, which is included in "Other noncurrent assets" and "Prepaid expenses and other" on the Consolidated Balance Sheet. As of December 31, 2014, none of QEP's cash and cash equivalents were restricted.

Supplemental cash flow information is shown in the table below:

	Year Ended December 31,		
	2015	2014	2013
Supplemental Disclosures	(in millions)		
Cash paid for interest, net of capitalized interest	$139.4	$163.2	$156.7
Cash paid for income taxes	487.8	0.3	77.9
Non-cash investing activities			
Change in capital expenditure accrual balance	$(129.2)	$8.4	$(25.2)

Accounts Receivable Trade

Accounts receivable trade 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, 2015, 2014 and 2013, was $0.5 million, $2.1 million, and $0.1 million, respectively. The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectability. The allowance for bad debt expenses was $3.9 million at December 31, 2015, and $4.6 million at December 31, 2014.

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 well 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, an impairment of oil and gas reserves caused by mechanical problems, faster-than-expected decline of reserves, lease ownership issues, and other than temporary declines in gas, oil and NGL prices. If impairment is indicated, fair value is calculated 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, 2015, QEP recorded impairment charges of $55.6 million, of which $39.3 million was related to proved properties due to lower future oil and gas prices, $2.0 million was related to expiring leaseholds on unproved properties and $14.3 million was related to the impairment of goodwill. Of the $39.3 million impairment on proved properties, $20.2 million related to impairments on QEP's remaining Midcontinent properties, $18.4 million related to impairments on the Other Northern properties and $0.7 million related to impairments on 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 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 impairments on Haynesville properties,

$467.7 million related to impairments on Permian Basin properties, $18.7 million related to impairments on QEP's remaining Midcontinent properties, $13.5 million related to impairments on the Other Northern properties, $5.8 million related to impairments on Williston Basin properties, and $3.6 million related to impairments on Uinta Basin properties.

During the year ended December 31, 2013, QEP recorded impairment charges of $93.0 million on its oil and gas properties, of which $1.2 million related to price-related impairment charges on proved properties and $32.3 million related to impairment on unproved properties due to lease expirations and changes in drilling plans. An additional $59.5 million of impairment was recorded due to the write-off of goodwill. See Goodwill section within this note for additional information.

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 asset retirement obligation 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 net 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 considered estimated quantities of gas, oil 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, 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 forecasted oil 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. During the performance of QEP's annual goodwill impairment test at December 31, 2013, QEP failed the first step of the goodwill impairment test as described above, primarily due to lower forecasted oil and NGL prices. QEP performed the second step test described above, which resulted in a full write down of goodwill of $59.5 million as of December 31, 2013.

Litigation and Other Contingencies

In accordance with ASC 450, Contingencies, an accrual is recorded for a loss contingency when its occurrence is probable and damages can be reasonably estimated based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes. QEP regularly reviews contingencies to determine the adequacy of its accruals and related disclosures. The amount of ultimate loss may differ from these estimates. See Note 10 – Commitments and Contingencies for additional information.

Except for environmental contingencies acquired in a business combination, which are recorded at fair value, QEP accrues 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 Instruments

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 gas or oil 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 enter into commodity derivative instruments for speculative purposes. 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 net income in the month of settlement. These contracts are also marked-to-market monthly with any change in the valuation also recognized in net income. See Note 7 – Derivative Contracts for additional information.

Credit Risk

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 individuals and numerous commercial and industrial enterprises that may react differently to changing conditions. Management believes that its credit review procedures, loss reserves, customer deposits and collection procedures have adequately provided for usual and customary credit-related losses. Commodity-based derivative contracts also expose the Company to credit risk. The Company monitors the creditworthiness of its counterparties, which generally are major financial institutions and energy companies. Loss reserves are periodically reviewed for adequacy and may be established on a specific case basis. QEP requests credit support and, in some cases, fungible collateral, financial guarantees, letters of credit or prepayment from companies with unacceptable credit risks. The Company has master-netting agreements with some counterparties that allow the offsetting of receivables and payables in a default situation.

The Company's five largest customers accounted for 30%, 33%, and 38% of QEP's revenues for the years ended December 31, 2015, 2014 and 2013, respectively. During the year ended December 31, 2015, no customer accounted for 10% or more of the Company's total revenues. During the year ended December 31, 2014, Valero Marketing and Supply Company accounted for 10% of the Company's total revenues. During the year ended December 31, 2013, Freepoint Commodities, LLC accounted for 13% of the Company'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, 2015, the Company has a valuation allowance of $20.3 million against the state net operation 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 2015 have been examined by the Internal Revenue Service and are closed. Income tax returns for 2015 have not yet been filed. Most state tax returns for 2012 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, 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. As of December 31, 2014, no uncertain tax positions had been recorded. During the year ended December 31, 2015, the Company incurred $0.5 million of interest expense and $2.2 million of penalties related to uncertain tax positions.

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 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. This program expired on December 31, 2015. 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.

Earnings Per Share

Basic earnings per share (EPS) are computed by dividing net income attributable to QEP 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 shares are considered issued and outstanding, the historical forfeiture rate is minimal and the restricted shares 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 year ended December 31, 2015, there were no anti-dilutive shares. For the year ended December 31, 2014, 0.3 million shares were not included in diluted common shares outstanding as they were anti-dilutive due to QEP's net loss from continuing operations. A reconciliation of the components of basic and diluted shares used in the EPS calculation follows:

	December 31,		
	2015	2014	2013
	(in millions)		
Weighted-average basic common shares outstanding	176.6	179.8	179.2
Potential number of shares issuable upon exercise of in-the-money stock options under the Long-Term Stock Incentive Plan	—	—	0.3

Average diluted common shares outstanding	176.6	179.8	179.5

Share-Based Compensation

QEP issues stock options and restricted shares 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 granting of restricted shares results in recognition of compensation cost measured at the grant-date market price. QEP uses an accelerated method in recognizing share-based compensation costs 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 shares vest in equal installments over a specified number of years after the grant date with the majority vesting in three years. Non-vested restricted shares have voting and dividend rights; however, sale or transfer is restricted. The Company also awards performance share units under its Cash Incentive Plan (CIP), which are denominated in share units but have historically been delivered in cash depending upon the Company's total shareholder return compared to a group of its peers over a three-year period. The performance share unit's compensation cost is equal to its fair value as of the period-end and is classified as a liability. See Note 11 – Share-Based Compensation for additional information.

Pension and Other Postretirement Benefits

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 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. Comprehensive income 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.

Business Segments

Line of business information is presented according to senior management's basis for evaluating performance considering differences in the nature of products, services and regulation. QEP's lines of business are QEP Energy and QEP Marketing and Other. QEP's former reporting segment, QEP Field Services, excluding the retained ownership of the Haynesville gathering system (Haynesville Gathering), was sold in 2014 and has been classified as a discontinued operation on the Consolidated Statement of Operations and the Notes accompanying the Consolidated Financial Statements. Haynesville Gathering is included in the reporting segment QEP Marketing and Other.

Recent Accounting Developments

In November 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standard Update (ASU) No. 2015-17, Income Taxes (Topic 740), which requires that deferred income tax liabilities and assets be classified as noncurrent on the consolidated balance sheet to simplify the presentation of deferred income taxes. The amendment will be effective prospectively for reporting periods beginning on or after December 15, 2016, and early adoption is permitted. The Company implemented this amendment effective December 31, 2015, and it did not have a significant impact on the Company's Consolidated Financial Statements.

In September 2015, the FASB issued ASU No. 2015-16, Business Combinations (Topic 805), which requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The amendment will be effective prospectively for reporting periods beginning on or after December 15, 2015, and early adoption is permitted. The Company is currently assessing the ASU and does not expect that there will be a significant impact on the Company's Consolidated Financial Statements.

In May 2014, the FASB issued ASU 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 July 2015, the FASB issued ASU 2015-14, Revenue from Contracts with Customers (Topic 606), in which the FASB delayed the effective date of the new revenue standard by one year and the amendments are now effective prospectively for reporting periods beginning after December 15, 2017, and early adoption is not permitted. The Company is currently assessing the impact of the ASU on the Company's Consolidated Financial Statements.

In May 2015, the FASB issued ASU No. 2015-07, Fair Value Measurement (Topic 820), which allows reporting entities to exclude investments measured at net asset value per share under the existing practical expedient in ASC 820 from the fair value hierarchy. It also limits disclosures to investments for which the entity has elected to measure the fair value using the practical expedient. The amendment will be effective retrospectively for reporting periods beginning on or after December 15, 2015, and early adoption is permitted. The Company is currently assessing the ASU and does not expect that there will be a significant impact on the Company's Consolidated Financial Statements.

In April 2015, the FASB issued ASU No. 2015-05, Intangibles — Goodwill and Other — Internal-Use Software (Subtopic 350-40), which assists entities in evaluating the accounting for fees paid by a customer in a "cloud computing arrangement" by providing guidance as to whether an arrangement includes the sale or license of software. The amendment will be effective prospectively for reporting periods beginning on or after December 15, 2015, and early adoption is permitted. The Company is currently assessing the ASU and does not expect that there will be a significant impact on the Company's Consolidated Financial Statements.

In April 2015, the FASB issued ASU No. 2015-03, Interest — Imputation of Interest (Subtopic 835-30), which simplifies the presentation of debt issuance costs by requiring that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts or premiums. The amendments will be effective retrospectively for reporting periods beginning on or after December 15, 2015, and early adoption is permitted. The Company plans to implement the ASU effective January 1, 2016, and does not expect that there will be a significant impact on the Company's Consolidated Financial Statements.

In February 2015, the FASB issued ASU No. 2015-02, Consolidation (Topic 810), which amends the current consolidation guidance. The amendment affects both the variable interest entity and voting interest entity consolidation models. The amendment will be effective prospectively for reporting periods beginning on or after December 15, 2015, and early adoption is permitted. The Company is currently assessing the ASU and does not expect that there will be a significant impact on the Company's Consolidated Financial Statements.

In January 2015, the FASB issued ASU No. 2015-01, Income Statement — Extraordinary and Unusual Items (Subtopic 225-20), which eliminates the concept of extraordinary items from GAAP. The amendment will be effective for reporting periods beginning on or after December 15, 2015, and early adoption is permitted. Additionally, a reporting entity also may apply the amendment retrospectively for all periods presented in the financial statements. The Company is currently assessing the ASU and does not expect that there will be a significant impact on the Company's Consolidated Financial Statements.

Note 2 – Acquisitions and Divestitures

Permian Basin Acquisition

On February 25, 2014, QEP Energy acquired oil and gas properties in the Permian Basin of Texas 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 Energy.

The 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 Permian Basin Acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. 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 years ended December 31, 2014 and 2013. Pro forma results are not provided for the year ended December 31, 2015, because the Permian Basin Acquisition occurred during the first quarter of 2014, and therefore the Permian Basin results are included in QEP's results for this period. 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 years ended December 31, 2014 and 2013, 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 may result from the 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,			
	2014		2013	
	Actual	Pro Forma	Actual	Pro Forma
	(in millions, except per share amounts)			
Revenues	$3,293.2	$3,319.3	$2,685.1	$2,858.8
Net income	784.4	791.4	159.4	195.3
Earnings per common share				
Basic	$4.36	$4.40	$0.89	$1.09
Diluted	4.36	4.40	0.89	1.09

Other Acquisitions

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's operated wells and undeveloped acreage. As a part of the purchase price allocation, the Company recorded $14.3 million of goodwill.

Divestitures

During 2015, QEP sold its interest in certain non-core properties for aggregate proceeds of $31.7 million and a recorded a pre-tax gain on sale of $21.0 million.

During 2014, QEP sold its interest in certain non-core properties in the Midcontinent and Williston Basin for aggregate proceeds of $783.8 million. For the year ended December 31, 2014, QEP recorded a pre-tax loss on sale of $147.0 million. QEP recorded a pre-tax loss on sale of $9.3 million for the year ended December 31, 2015, due to post-closing purchase price adjustments from the sale of such properties.

During 2013, QEP Energy sold its interests in several non-core properties for aggregate proceeds of $205.8 million and recorded a pre-tax gain on sale of $105.7 million.

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

Note 3 – Discontinued Operations

On December 2, 2014, the Company closed the sale of 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 operating results of QEP Field Services Company (QEP Field Services), excluding Haynesville Gathering (the Discontinued Operations of QEP Field Services), was classified as discontinued operations on the Consolidated Statements of Operations and Notes accompanying the Consolidated Financial Statements for the years ended December 31, 2014 and 2013. 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, 2015, 2014 and 2013, cash outflows for these transactions included in continuing operations were $131.8 million, $145.3 million and $124.6 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 is 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 Operations

The Discontinued Operations of QEP Field Services are summarized below:

	Year Ended December 31,	
	2014	2013
	(in millions)	
REVENUES		
NGL sales	$109.3	$101.9
Other revenues	140.9	166.6
Purchased gas and oil sales[1]	(47.1)	(17.8)
Total Revenues	203.1	250.7
OPERATING EXPENSES		
Purchased gas and oil expense[1]	(48.5)	(17.6)
Lease operating expense[1]	(5.5)	(3.5)
Gas, oil and NGL transport & other handling costs[1]	(55.4)	(80.6)
Gathering, processing, and other	85.9	82.2
General and administrative	42.1	30.7
Production and property taxes	7.3	5.2
Depreciation, depletion and amortization	45.9	52.2
Total Operating Expenses	71.8	68.6
Net gain (loss) from asset sales	1,793.4	(0.5)
OPERATING INCOME	1,924.7	181.6
Interest and other income (expense)	0.3	(10.0)
Income from unconsolidated affiliates	4.9	5.6
Loss on early extinguishment of debt	(2.4)	—
Interest expense (income)	(3.8)	1.8
INCOME FROM DISCONTINUED OPERATIONS BEFORE INCOME TAXES [2]	1,923.7	179.0
Income tax provision	(708.2)	(59.7)
NET INCOME FROM DISCONTINUED OPERATIONS	1,215.5	119.3
Net income attributable to noncontrolling interest	(21.6)	(12.0)
NET INCOME FROM DISCONTINUED OPERATIONS, NET OF INCOME TAX	$1,193.9	$107.3

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(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 and $33.5 million for the years ended December 31, 2014 and 2013, respectively.

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 and $52.2 million for the years ended December 31, 2014 and 2013, respectively. 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 and $88.9 million for the years ended December 31, 2014 and 2013, respectively.

Note 4 – Capitalized Exploratory Well Costs

Net changes in capitalized exploratory well costs are presented in the table below. The balances at December 31, 2015, 2014 and 2013, represent the amount of capitalized exploratory well costs that are pending the determination of proved reserves.

	2015	2014	2013
	(in millions)		
Balance at January 1,	$12.6	$2.6	$2.1
Additions to capitalized exploratory well costs pending the determination of proved reserves	6.0	13.7	2.7
Reclassifications to proved properties after the determination of proved reserves	(16.0)	—	(2.2)
Capitalized exploratory well costs charged to expense	—	(3.7)	—
Balance at December 31,	$2.6	$12.6	$2.6

Note 5 – Asset Retirement Obligations

QEP records ARO when there are legal obligations 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 $206.8 million and $195.1 million ARO liability for the years ended December 31, 2015 and 2014, respectively, $1.9 million and $1.3 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	
	2015	2014
	(in millions)	
ARO liability at January 1,[1]	$195.1	$165.1
Accretion	8.7	6.7
Additions[2]	3.8	17.1
Revisions	17.2	33.6
Liabilities related to assets sold	(16.0)	(24.7)
Liabilities settled	(2.0)	(2.7)
ARO liability at December 31,	$206.8	$195.1

(1) Excludes $28.5 million of ARO as of January 1, 2014, classified as "Noncurrent liabilities of discontinued operations" on the Consolidated Balance Sheet.

(2) Additions for the year ended December 31, 2014, include $9.7 million related to the 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, 2015 and 2014, is shown in the table below:

	Fair Value Measurements Gross Amounts of Assets and Liabilities			Netting Adjustments[1]	Net Amounts Presented on the Consolidated Balance Sheet
	Level 1	Level 2	Level 3		
	(in millions)				
	December 31, 2015				
Financial Assets					
Commodity derivative instruments - short-term	$—	$147.8	$—	$(1.0)	$146.8
Commodity derivative instruments - long-term	—	23.2	—	—	23.2
Total financial assets	$—	$171.0	$—	$(1.0)	$170.0
Financial Liabilities					
Commodity derivative instruments - short-term	$—	$1.8	$—	$(1.0)	$0.8
Commodity derivative instruments - long-term	—	4.0	—	—	4.0
Total financial liabilities	$—	$5.8	$—	$(1.0)	$4.8
	December 31, 2014				
Financial Assets					
Commodity derivative instruments - short-term	$—	$339.3	$—	$(0.3)	$339.0
Commodity derivative instruments - long-term	—	9.9	—	—	9.9
Total financial assets	$—	$349.2	$—	$(0.3)	$348.9
Financial Liabilities					
Commodity derivative instruments - short-term	$—	$0.3	$—	$(0.3)	$—
Total financial liabilities	$—	$0.3	$—	$(0.3)	$—

[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, 2015		December 31, 2014	
	(in millions)			
Financial Assets				
Cash and cash equivalents	$376.1	$376.1	$1,160.1	$1,160.1
Financial Liabilities				

Checks outstanding in excess of cash balances	$29.8	$29.8	$54.7	$54.7
Long-term debt	2,218.8	1,784.6	2,218.1	2,171.6

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, non-financial 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, 2015 and 2014, the Company recorded impairments on certain oil and gas properties resulting in a write down 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. Given the unobservable nature of the inputs, proved oil and gas property impairments are considered Level 3 within the fair value hierarchy. During the years ended December 31, 2015 and 2014, the Company recorded $39.3 million and $1,041.4 million, respectively, of impairments related to certain of its proved properties. The proved properties were written down to their estimated fair values at the time of the impairments during December 31, 2015 and 2014, respectively.

Acquisitions of proved and unproved properties are also measured at fair value on a nonrecurring basis. The Company utilized a discounted cash flow model to estimate the fair value of acquired property as of the acquisition date which utilized the following inputs to estimate future net cash flows: estimated quantities of gas, oil and NGL reserves; estimates of future commodity prices; and estimated production rates, future operating and development costs, which were 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 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 from proved reserves, 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 and marketing transactions. QEP does not enter into commodity derivative instruments 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 gas or oil 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. Gas price derivative instruments are typically structured as fixed-price swaps or collars at regional price indices. Oil price derivative instruments are typically structured as NYMEX fixed-price swaps based at Cushing, Oklahoma or oil price swaps that use Intercontinental Exchange, Inc. (ICE) Brent oil prices as the reference price. QEP also enters into crude oil and natural gas basis swaps to achieve a fixed-price swap for a portion of its oil and gas it sells 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. Commodity derivative contract counterparties are normally 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 and avoids concentration of credit exposure by transacting with multiple counterparties.

During 2014 and 2013, 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.

QEP Energy Derivative Contracts

The following table sets forth QEP Energy's quantities and average prices for its commodity derivative swap contracts as of December 31, 2015:

Year	Index	Total Volumes	Average Swap Price per unit
		(in millions)	
Gas sales		(MMBtu)	($/MMBtu)
2016	NYMEX HH	51.2	$2.83
2016	IFNPCR	65.9	$2.57
2017	NYMEX HH	40.2	$2.83
2017	IFNPCR	21.9	$2.52
Oil sales		(bbls)	($/bbl)
2016	NYMEX WTI	6.6	$58.00
2017	NYMEX WTI	2.6	$54.39

The following table sets forth QEP Energy's gas collars as of December 31, 2015:

Year	Index	Total Volume	Average Price Floor	Average Price Ceiling
		(in millions)		
		(MMBtu)	($/MMBtu)	($/MMBtu)
2016	NYMEX HH	7.3	$2.75	$3.89

QEP uses gas basis swaps, combined with NYMEX HH fixed price swaps, to achieve fixed price swaps at the location at which it sells its physical production.

The following table sets forth QEP Energy's gas basis swaps as of December 31, 2015:

Year	Index Less Differential	Index	Total Volumes	Weighted-Average Differential
			(in millions)	
			(MMBtu)	($/MMBtu)
2016	NYMEX HH	IFNPCR	29.3	$ (0.15)
2017	NYMEX HH	IFNPCR	7.3	$ (0.20)

QEP Marketing Derivative Contracts

QEP Marketing enters into commodity derivative transactions to lock in a margin on gas volumes placed into storage and for marketing transactions in which QEP Marketing sells gas volumes at a fixed price. The following table sets forth QEP Marketing's volumes and swap prices for its commodity derivative contracts as of December 31, 2015:

Year	Type of Contract	Index	Total Volumes	Average Swap Price per MMBtu
			(in millions)	
Gas sales			(MMBtu)	
2016	SWAP	IFNPCR	2.3	$2.87
Gas purchases			(MMBtu)	
2016	SWAP	IFNPCR	0.2	$2.11

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 in 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	2015	2014	2015	2014
		(in millions)			
Current:					
Commodity	Fair value of derivative contracts	$147.8	$339.3	$1.8	$0.3
Long-term:					
Commodity	Fair value of derivative contracts	23.2	9.9	4.0	—
Total derivative instruments		$171.0	$349.2	$5.8	$0.3

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:

Derivative instruments not designated as cash flow hedges	Year Ended December 31,		
	2015	2014	2013
Realized gains (losses) on commodity derivative contracts	(in millions)		
QEP Energy			
Gas derivative contracts	$103.4	$(16.7)	$152.0
Oil derivative contracts	353.7	15.7	(2.2)
QEP Marketing			
Gas derivative contracts	3.8	(2.5)	0.5
Total realized gains (losses) on commodity derivative contracts	460.9	(3.5)	150.3
Unrealized gains (losses) on commodity derivative contracts			
QEP Energy			
Gas derivative contracts	62.0	68.4	(42.6)
Oil derivative contracts	(244.9)	299.8	(48.1)
QEP Marketing			
Gas derivative contracts	(0.8)	4.2	(2.1)
Total unrealized gains (losses) on commodity derivative contracts	(183.7)	372.4	(92.8)
Total realized and unrealized gains (losses) on commodity derivative contracts	$277.2	$368.9	$57.5
Realized gains (losses) on interest rate swaps			
Realized losses on interest rate swaps	$—	$(7.6)	$(2.7)
Unrealized gains (losses) on interest rate swaps			
Unrealized gains (losses) on interest rate swaps	—	2.0	4.1
Total realized and unrealized gains (losses) on interest rate swaps	—	(5.6)	1.4
Total net realized gains (losses) on derivative contracts	460.9	(11.1)	147.6
Total net unrealized gains (losses) on derivative contracts	(183.7)	374.4	(88.7)
Grand Total	$277.2	$363.3	$58.9

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Note 8 – Restructuring Costs

In the third quarter of 2015, QEP announced the closure of its regional office in Tulsa, Oklahoma. As a part of this reorganization, QEP incurred costs associated with termination benefits, relocation of certain employees and other expenses. The Company estimates that the total costs related to the Tulsa office closure will be approximately $5.4 million, of which approximately $2.6 million is related to one-time termination benefits and approximately $2.8 million is related to relocation of certain employees. During the year ended December 31, 2015, restructuring costs of $5.0 million were incurred related to the Tulsa office closure, of which $2.6 million was related to one-time termination benefits and $2.4 million was related to relocation of certain employees. QEP also incurred restructuring costs related to one-time termination benefits of approximately $2.7 million in the first quarter of 2015 as a result of work force reductions unrelated to the closure of its Tulsa office. All of the costs were incurred by QEP Energy and reported within QEP Energy's financial statements. These restructuring costs were recorded within "General and administrative" expense on the Consolidated Statement of Operations. The Company estimates that the remaining $0.4 million of restructuring costs related to the Tulsa office closure will be incurred in 2016.

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

	Restructuring Liability
	(in millions)
Balance at December 31, 2014	$—
Costs incurred and charged to expense	7.7
Costs paid or otherwise settled	(7.7)
Balance at December 31, 2015	$—

Note 9 – Debt

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

	December 31,	
	2015	2014
	(in millions)	
Revolving Credit Facility due 2019	$—	$—
6.05% Senior Notes due 2016	176.8	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	(3.0)	(3.7)
Total principal amount of debt (including current portion)	2,218.8	2,218.1
Less: current portion of long-term debt	(176.8)	—
Total long-term debt outstanding	$2,042.0	$2,218.1

Of the total debt outstanding on December 31, 2015, the 6.05% Senior Notes due September 1, 2016, the 6.80% Senior Notes due April 1, 2018 and the 6.80% Senior Notes due March 1, 2020, 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 (as defined in the credit agreement) that limit the amount of debt the Company can incur which includes: (i) a net funded debt to capitalization ratio than 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, 2015 and 2014, QEP was in compliance with the covenants under the credit agreement.

During the year ended December 31, 2015, QEP had no borrowings outstanding under the credit facility. During the year ended December 31, 2014, QEP's weighted-average interest rate on borrowings from its credit facility was 2.23%. At December 31, 2015 and 2014, QEP had no borrowings outstanding and had $3.4 million and $3.7 million, respectively, in letters of credit outstanding under the credit facility.

Senior Notes

At December 31, 2015, the Company had $2,221.8 million principal amount of senior notes outstanding with maturities ranging from September 2016 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

QEP is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business. QEP 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. Because 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, QEP may be unable to provide a meaningful estimate due to a number of factors, including the procedural status of the matter in question, the presence of complex or novel legal theories, the ongoing discovery and/or development of information important to the matter.

Litigation

Rocky Mountain Resources Lawsuit – Rocky Mountain Resources, LLC (Rocky Mountain) filed its complaint in March 2011, seeking determination of the existence of a 4% overriding royalty interest in an oil and gas lease. Rocky Mountain alleges that the defendants have 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 QEP and awarded Rocky Mountain damages in the amount of $16.7 million, including interest. QEP is appealing the verdict to the Wyoming Supreme Court, and, in connection with such appeal, has posted a bond for approximately $20.0 million (representing the amount of the verdict and two years of accrued interest at the statutory rate of 10%). In accordance with the Court's order, QEP is depositing the future monthly revenues attributable to the 4% overriding royalty interest with the Court as it becomes due and owing. The overriding royalty payments will be subject to the direction of the Court following the conclusion of the appeal. QEP estimates that, notwithstanding the verdict, the range of reasonably possible losses is still zero to approximately $20.0 million.

Commitments

Subsidiaries of QEP have contracted for gathering, processing, firm transportation and storage services with various third-party pipelines. 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
2016	$ 126.4
2017	$ 129.4
2018	$ 111.8
2019	$ 105.0
2020	$ 87.8
After 2020	$ 259.0

QEP rents office space throughout its scope of operations from third-party lessors. Rental expense from operating leases amounted to $8.0 million, $8.2 million, and $7.8 million during the years ended December 31, 2015, 2014 and 2013, respectively. Minimum future payments under the terms of long-term operating leases for the Company's primary office locations and utilities are as follows (in millions):

Year	Amount
2016	$ 9.7
2017	$ 9.8
2018	$ 8.5
2019	$ 7.6
2020	$ 7.4
After 2020	$ 18.6

Note 11 – Share-Based Compensation

QEP issues stock options and restricted shares 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 shares and performance share units. There were 9.3 million shares available for future grants under the LTSIP at December 31, 2015. Share-based compensation expense related to continuing operations is recognized within "General and administrative" expense on the Consolidated Statements of Operations, and expenses related to discontinued operations (including compensation expense related to the QEP Midstream Long Term Incentive Plan) are reflected within "Net income from discontinued operations, net of income tax" on the Consolidated Statement of Operations. During the year ended December 31, 2015, QEP recognized $34.7 million in total compensation expense related to share-based compensation for continuing operations, compared to $21.4 million and $25.7 million during the years ended December 31, 2014 and 2013, respectively. In addition, during the year ended December 31, 2014, QEP recognized $5.8 million in total compensation expense related to discontinued operations, compared to $1.4 million during the year ended December 31, 2013.

Stock Options

QEP uses the Black-Scholes-Merton mathematical model to estimate the fair value of stock option awards at the date of the 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 measuring the value of options 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,		
	2015	2014	2013
Weighted-average grant date fair value of awards granted during the period	$6.82	$10.11	$15.16
Risk-free interest rate range	1.38% - 1.38%	1.31% - 1.34%	0.97% - 1.84%
Weighted-average risk-free interest rate	1.4 %	1.3 %	1.0 %
Expected price volatility range	36.8% - 36.8%	36.1% - 37.3%	51.5% - 58.5%
Weighted-average expected price volatility	36.8 %	37.1 %	58.3 %
Expected dividend yield	0.37 %	0.25 %	0.27 %
Expected term in years at the date of grant	4.5	4.5	5.5

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

	Options Outstanding	Weighted-Average Exercise Price (per share)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in millions)
Outstanding at December 31, 2014	1,996,215	$28.60		
Granted	425,877	21.69		
Exercised	(15,000)	19.37		

Forfeited	(2,817)	31.31		
Canceled	(203,499)	21.87		
Outstanding at December 31, 2015	2,200,776	$27.94	3.19	$—
Options Exercisable at December 31, 2015	1,522,326	$29.17	2.10	$—
Unvested Options at December 31, 2015	678,450	$25.20	5.63	$—

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, $0.6 million and $4.3 million during the years ended December 31, 2015, 2014 and 2013, respectively. The Company realized an income tax expense of $6.4 million for the year ended December 31, 2015, no income tax impact for the year ended December 31, 2014, and $1.4 million of income tax benefits for the year ended December 31, 2013, which increased its Additional Paid-in-Capital (APIC) pool by $0.1 million as of December 31, 2015. As of December 31, 2015, $1.9 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 1.96 years. During the year ended December 31, 2015, QEP issued shares for stock option exercises from its treasury stock and issued new shares. In addition, QEP received $0.3 million in cash in relation to the exercise of stock options.

Restricted Shares

Restricted share 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 stock that vested during the years ended December 31, 2015, 2014 and 2013, was $22.7 million, $26.8 million and $19.8 million, respectively. The Company realized an income tax benefit of $3.2 million for the year ended December 31, 2015, and income tax expense of $0.5 million and $0.1 million for the years ended December 31, 2014, and 2013, respectively. Restricted stock increased the Company's APIC pool by $3.5 million as of December 31, 2015. The weighted-average grant date fair value of restricted stock granted was $20.92 per share, $31.40 per share and $30.06 per share for the years ended December 31, 2015, 2014 and 2013, respectively. As of December 31, 2015, $20.3 million of unrecognized compensation cost related to restricted shares 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 2.04 years.

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

	Restricted Shares Outstanding	Weighted-Average Grant Date Fair Value (per share)
Unvested balance at December 31, 2014	1,426,453	$31.02
Granted	1,509,384	20.92
Vested	(748,157)	30.33
Forfeited	(179,470)	25.45
Unvested balance at December 31, 2015	2,008,210	$24.18

Performance Share Units

The performance share units' cash payouts 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, 2015, the Company expects to settle all awards in cash. The weighted-average grant date fair values of the performance share units granted during the years ended December 31, 2015, 2014 and 2013, were $21.69, $31.57, and $30.12 per share, respectively. As of December 31, 2015, $4.5 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 1.75 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, 2014	552,209	$30.85
Granted	234,085	21.69
Vested and paid out	(131,665)	30.77
Canceled [1]	(14,612)	30.77
Forfeited	(9,231)	29.19
Unvested balance at December 31, 2015	630,786	$27.50

[1] Represents units that were not paid out due to performance under the Plan.

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 (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 coverage to 50 active and suspended participants, or 7%, of QEP's active employees, and to 164 participants that are retired or 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, 2015, 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 2016. 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 will be 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, 2015, the Company made contributions of $3.5 million to its SERP and expects to contribute approximately $2.9 million of benefits in 2016. Contributions to the SERP are used to fund current benefit payments. The SERP was amended and restated in June 2015 and will be 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 employees. The Medical Plan is provided only to employees hired before January 1, 1997. Of the 50 active, pension eligible employees, 29 are also eligible for the Medical Plan when they retire. As of December 31, 2015, 51 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, 2015, the Company made contributions of $0.2 million and expects to contribute approximately $0.3 million of benefits in 2016. At December 31, 2015 and 2014, 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 Midcontinent 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 Midcontinent property sales 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 $117.4 million and $121.8 million at December 31, 2015 and 2014, 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, 2015 and 2014, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2015 and 2014:

	Pension Plan and SERP benefits		Medical Plan benefits	
	2015	2014	2015	2014
	(in millions)			
Change in benefit obligation				
Benefit obligation at January 1,	$132.6	$118.0	$6.6	$5.9
Service cost	2.1	2.6	—	—
Interest cost	4.9	5.3	0.2	0.3
Special termination benefits	—	1.9	—	—
Curtailments	(7.1)	(8.2)	—	(0.2)
Plan settlements	—	(2.3)	—	—
Benefit payments	(7.7)	(5.5)	(0.2)	—
Plan amendments	0.9	—	—	—
Actuarial loss (gain)	(5.4)	20.8	(1.4)	0.6
Benefit obligation at December 31,	$120.3	$132.6	$5.2	$6.6
Change in plan assets				
Fair value of plan assets at January 1,	$81.4	$71.7	$—	$—
Actual gain (loss) on plan assets	(1.9)	4.5	—	—
Company contributions to the plan	7.5	13.0	0.2	—
Benefit payments	(7.7)	(5.5)	(0.2)	—
Plan settlements	—	(2.3)	—	—
Fair value of plan assets at December 31,	79.3	81.4	—	—
Underfunded status (current and long-term)	$(41.0)	$(51.2)	$(5.2)	$(6.6)
Amounts recognized in balance sheets				
Accounts payable and accrued expenses	$(2.9)	$(4.3)	$(0.3)	$(0.3)
Other long-term liabilities	(38.1)	(46.9)	(4.9)	(6.3)
Total amount recognized in balance sheet	$(41.0)	$(51.2)	$(5.2)	$(6.6)
Amounts recognized in AOCI				
Net actuarial loss (gain)	$15.8	$21.2	$(0.8)	$0.6
Prior service cost	4.1	16.1	1.2	1.4
Total amount recognized in AOCI	$19.9	$37.3	$0.4	$2.0

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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		
	2015	2014	2013	2015	2014	2013
	(in millions)					
Components of net periodic benefit cost						
Service cost	$2.1	$2.6	$3.3	$—	$—	$0.1
Interest cost	4.9	5.3	4.8	0.2	0.3	0.3
Expected return on plan assets	(5.7)	(5.1)	(3.9)	—	—	—
Curtailment loss	11.2	9.3	—	—	1.4	—
Special termination benefits	—	1.9	—	—	—	—
Settlements	—	0.7	—	—	—	—
Amortization of prior service costs	1.7	4.7	5.0	0.2	0.3	0.3
Amortization of actuarial loss	0.5	0.8	2.3	—	—	0.1
Periodic expense	$14.7	$20.2	$11.5	$0.4	$2.0	$0.8
Components recognized in accumulated other comprehensive income						
Current period actuarial loss (gain)	$2.2	$21.5	$(20.8)	$(1.4)	$0.6	$(1.0)
Amortization of actuarial gain (loss)	(0.5)	(0.8)	(2.3)	—	—	(0.1)
Amortization of prior service cost	(12.9)	(14.0)	(5.0)	(0.2)	(1.7)	(0.4)
Current year prior service cost	0.9	—	—	—	—	—
Loss on curtailment in current period	(7.1)	(8.2)	—	—	(0.2)	—
Settlements	—	(0.7)	—	—	—	—
Total amount recognized in accumulated other comprehensive income	$(17.4)	$(2.2)	$(28.1)	$(1.6)	$(1.3)	$(1.5)

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 2016 is $1.4 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 2016 is $0.2 million, which represents amortization of prior service cost recognition and actuarial gains. Amortization of prior service costs and actuarial gains or losses out of AOCI are recognized in the Consolidated Statements of Operations in "General and administrative."

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, 2015 and 2014:

	Pension Plan and SERP benefits		Medical Plan benefits	
	2015	2014	2015	2014
Discount rate	4.24 %	3.94 %	4.40 %	4.00 %
Rate of increase in compensation	4.00 %	4.00 %	4.00 %	4.00 %

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		
	2015	2014	2013	2015	2014	2013

Discount rate	3.94	%	4.40	%	3.69	%	4.00	%	5.00	%	4.10	%
Expected long-term return on plan assets	6.75	%	7.00	%	6.75	%	n/a		n/a		n/a	
Rate of increase in compensation	4.00	%	4.00	%	3.60	%	4.00	%	4.00	%	3.60	%

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 2016. 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. Foreign equity securities consisted of developed and emerging market foreign equity assets that were invested in funds that hold 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 5 to 10 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 5 to 7 years.

Although the actual allocation to cash and short-term investments is minimal (less than 1%), 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.

Commingled funds: 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. While commingled funds are classified as Level 3 assets because there are calculations involved in determining the net asset value of the funds, the underlying assets can be traced back to observable asset values and 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. The Company's Level 3 investments are public investment vehicles valued using the net asset value (NAV) of the fund, but are considered Level 3 because they are commingled funds. The NAV is based on the value of the underlying assets owned by the fund excluding transaction costs, and minus liabilities.

The following table sets forth by level, within the fair value hierarchy, the fair value of the Pension Plan assets:

	December 31, 2015				Percentage of
	Level 1	Level 2	Level 3	Total	total
	(in millions except percentages)				
Cash and short-term investments	$—	$—	$0.4	$0.4	— %
Equity securities:					
Domestic	—	—	38.5	38.5	49 %
International	—	—	16.8	16.8	21 %
Fixed income	—	—	23.6	23.6	30 %
Total investments	$—	$—	$79.3	$79.3	100 %

	December 31, 2014				Percentage of
	Level 1	Level 2	Level 3	Total	total
	(in millions except percentages)				
Cash and short-term investments	$—	$—	$0.3	$0.3	— %
Equity securities:					
Domestic	—	—	36.7	36.7	45 %
International	—	—	20.2	20.2	25 %
Fixed income	—	—	24.2	24.2	30 %
Total investments	$—	$—	$81.4	$81.4	100 %

The following table presents a summary of changes in the fair value of QEP's Level 3 investments:

	Year ended December 31,	
	2015	2014
	(in millions)	
Balance at January 1,	$81.4	$71.7
Employer contributions	4.0	8.1
Unrealized gains (losses)	(3.0)	(1.0)
Realized gains	1.6	5.9
Administrative fees	(0.6)	(0.4)
Benefits paid	(4.1)	(2.9)
Balance at December 31,	$79.3	$81.4

Expected Benefit Payments

As of December 31, 2015, the following future benefit payments are expected to be paid:

	Pension Plan and SERP benefits	Medical Plan benefits
	(in millions)	
2016	$7.3	$0.3
2017	$6.6	$0.3
2018	$5.9	$0.3
2019	$7.4	$0.3
2020	$7.2	$0.3
2021 through 2025	$40.7	$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 years ended December 31, 2015, 2014 and 2013, the Company made matching contributions for employees not covered by the Pension Plan equal to 100% of employees'

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contributions up to a maximum of 8% of their qualifying earnings. For the years ended December 31, 2015, 2014 and 2013, employees covered by the Pension Plan 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. The Company recognizes expense equal to its yearly contributions, which amounted to \$6.3 million, \$7.6 million and \$6.9 million during the years ended December 31, 2015, 2014 and 2013, 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,		
	2015	2014	2013
	(in millions)		
Federal income tax provision (benefit)			
Current	\$(112.3)	\$(324.0)	\$(92.2)
Deferred	34.5	110.3	152.3
State income tax provision (benefit)			
Current	(6.6)	(15.5)	(1.4)
Deferred	(9.2)	(3.3)	1.4
Total income tax provision (benefit)	\$(93.6)	\$(232.5)	\$60.1

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,		
	2015	2014	2013
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	4.2 %	(1.5)%	(5.0)%
State rate change	— %	3.4 %	— %
Penalties	(0.3)%	— %	0.4 %
Return to provision adjustment	(0.3)%	(0.4)%	5.0 %
Book impairment of goodwill	— %	— %	18.6 %
Other	(0.1)%	(0.3)%	(0.4)%
Effective income tax rate	38.5 %	36.2 %	53.6 %

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

	December 31,	
	2015	2014
	(in millions)	
Deferred tax liabilities		
Property, plant and equipment	\$1,531.0	\$1,402.9
Commodity price and interest rate derivatives	60.4	127.7
Total deferred tax liabilities	1,591.4	1,530.6
Deferred tax assets		
Net operating loss and tax credit carryforwards	51.9	11.7
Employee benefits and compensation costs	43.6	43.0
Bonus and vacation accrual	7.0	16.3
Other	9.1	12.4
Total deferred tax assets	111.6	83.4

Net deferred income tax liability	$1,479.8	$1,447.2
Balance sheet classification		
Deferred income tax asset - current	$—	$—
Deferred income tax liability - current	—	84.5
Deferred income tax liability - non-current	1,479.8	1,362.7
Net deferred income tax liability	$1,479.8	$1,447.2

The amounts and expiration dates of net operating loss and tax credit carryforwards at December 31, 2015 are as follows:

	Expiration Dates	Amounts (in millions)	
State net operating loss and tax credit carryforwards	2015-2033	$40.5	
State net operating loss valuation allowance		(20.3	)
U.S. alternative minimum tax credit	Indefinite	—	
Total		$20.2	

The valuation allowance of $20.3 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 Midcontinent property sales 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, 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. At December 31, 2014, no uncertain tax positions had been recorded. The uncertain tax positions the Company reported during the year ended December 31, 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, 2015, the Company incurred $0.5 million of interest expense and $2.2 million of penalties related to uncertain tax positions.

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

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

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

Note 14 – Operations by Line of Business

QEP's two lines of business include oil and gas exploration and production (QEP Energy) and oil and gas marketing, operation of a gas gathering system and an underground gas storage facility and corporate (QEP Marketing and Other). The lines of business are managed separately and, therefore, the financial information is presented separately due to the distinct differences in the nature of operations of each line of business, among other factors.

Our financial results for prior periods have been revised, in accordance with GAAP, to reflect the impact of the Midstream Sale. See Note 3 – Discontinued Operations for detailed information on the Midstream Sale.

The following table is a summary of operating results for the year ended December 31, 2015, by line of business:

	QEP Energy	QEP Marketing and Other	Eliminations	QEP Consolidated
	(in millions)			
REVENUES				
From unaffiliated customers	$1,477.2	$654.5	$(113.1)	$2,018.6
From affiliated customers	—	946.8	(946.8)	—
Total Revenues	1,477.2	1,601.3	(1,059.9)	2,018.6
OPERATING EXPENSES				
Purchased gas and oil expense	87.3	1,588.1	(1,048.6)	626.8
Lease operating expense	238.8	—	—	238.8
Gas, oil and NGL transportation and other handling costs	300.2	—	(8.9)	291.3
Gathering and other expense	—	5.8	—	5.8
General and administrative	176.8	6.7	(2.4)	181.1
Production and property taxes	115.1	2.5	—	117.6
Depreciation, depletion and amortization	870.8	10.3	—	881.1
Impairment and exploration expenses	58.3	—	—	58.3
Total Operating Expenses	1,847.3	1,613.4	(1,059.9)	2,400.8
Net gain (loss) from asset sales	9.7	(5.1)	—	4.6
OPERATING INCOME (LOSS)	(360.4)	(17.2)	—	(377.6)
Realized and unrealized gains (losses) on derivative contracts	274.2	3.0	—	277.2
Interest and other income	1.9	205.7	(204.6)	3.0
Interest expense	(204.5)	(145.7)	204.6	(145.6)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(288.8)	45.8	—	(243.0)
Income tax (provision) benefit	105.9	(12.3)	—	93.6
NET INCOME (LOSS)	$(182.9)	$33.5	$—	$(149.4)
Identifiable total assets	$7,799.5	$626.0	$—	$8,425.5
Cash capital expenditures	$1,233.3	$6.1	$—	$1,239.4
Accrued capital expenditures	$1,105.7	$4.5	$—	$1,110.2

The following table is a summary of operating results for the year ended December 31, 2014, by line of business:

	QEP Energy	QEP Marketing and Other	Eliminations	Discontinued Operations	QEP Consolidated
	(in millions)				
REVENUES					
From unaffiliated customers[1]	$2,524.6	$889.7	$(121.1)	$—	$3,293.2
From affiliated customers	—	1,492.6	(1,492.6)	—	—
Total Revenues	2,524.6	2,382.3	(1,613.7)	—	3,293.2
OPERATING EXPENSES					
Purchased gas and oil expense[1]	150.0	2,356.6	(1,596.5)	—	910.1
Lease operating expense	240.1	—	—	—	240.1
Gas, oil and NGL transportation and other handling costs	291.5	—	(13.9)	—	277.6
Gathering and other expense	—	6.8	(0.1)	—	6.7
General and administrative	201.3	6.3	(3.2)	—	204.4
Production and property taxes	204.0	1.2	—	—	205.2
Depreciation, depletion and amortization	984.4	10.3	—	—	994.7
Impairment and exploration expenses	1,153.1	—	—	—	1,153.1
Total Operating Expenses	3,224.4	2,381.2	(1,613.7)	—	3,991.9
Net gain (loss) from asset sales	(148.6)	—	—	—	(148.6)
OPERATING INCOME (LOSS)	(848.4)	1.1	—	—	(847.3)
Realized and unrealized gains (losses) on derivative contracts	367.2	(3.9)	—	—	363.3
Interest and other income	11.8	209.7	(208.7)	—	12.8
Income from unconsolidated affiliates	0.3	—	—	—	0.3
Loss from early extinguishment of debt	—	(2.0)	—	—	(2.0)
Interest expense	(210.3)	(167.5)	208.7	—	(169.1)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(679.4)	37.4	—	—	(642.0)
Income tax (provision) benefit	246.9	(14.4)	—		232.5
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	(432.5)	23.0	—	—	(409.5)
Net income from discontinued operations, net of income tax	—	—	—	1,193.9	1,193.9
NET INCOME (LOSS)	$(432.5)	$23.0	$—	$1,193.9	$784.4
Identifiable total assets	$8,001.1	$1,285.7	$—	$—	$9,286.8
Cash capital expenditures	$2,660.3	$10.9	$—	$55.2	$2,726.4
Accrued capital expenditures	$2,670.5	$13.6	$—	$50.7	$2,734.8

(1) In the fourth quarter of 2015, the Company determined that certain purchased oil transactions that had been included in "Revenues" and "Purchased gas and oil expense" on a gross basis should have been reported net, as the transactions were with the same counterparty and were entered into in contemplation of one another. The revisions had no effect on the Company’s operating income or net income. The following table details the impact to Eliminations of the revisions to the Consolidated Statement of Operations. See Note 1 – Summary of Significant Accounting Policies for additional information.

	Eliminations as Reported (in millions)	Eliminations as Revised	Change
From unaffiliated customers	$—	$(121.1)	$(121.1)
Purchased gas and oil expense	(1,475.4)	(1,596.5)	(121.1)

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The following table is a summary of operating results for the year ended December 31, 2013, by line of business:

	QEP Energy	QEP Marketing and Other	Eliminations	Discontinued Operations	QEP Consolidated
	(in millions)				
REVENUES					
From unaffiliated customers	$2,092.8	$592.3	$—	$—	$2,685.1
From affiliated customers	—	1,008.9	(1,008.9)	—	—
Total Revenues	2,092.8	1,601.2	(1,008.9)	—	2,685.1
OPERATING EXPENSES					
Purchased gas and oil expense	197.1	1,570.5	(984.1)	—	783.5
Lease operating expense	181.3	—	—	—	181.3
Gas, oil and NGL transportation and other handling costs	242.2	—	(20.2)	—	222.0
Gathering and other expense	—	8.4	—	—	8.4
General and administrative	160.6	4.4	(4.6)	—	160.4
Production and property taxes	159.8	1.5	—	—	161.3
Depreciation, depletion and amortization	954.2	9.6	—	—	963.8
Impairment and exploration expenses	104.9	—	—	—	104.9
Total Operating Expenses	2,000.1	1,594.4	(1,008.9)	—	2,585.6
Net gain from asset sales	104.1	(0.6)	—	—	103.5
OPERATING INCOME (LOSS)	196.8	6.2	—	—	203.0
Realized and unrealized gains (losses) on derivative contracts	59.1	(0.2)	—	—	58.9
Interest and other income	3.6	206.9	(195.3)	—	15.2
Income from unconsolidated affiliates	0.2	—	—	—	0.2
Interest expense	(192.6)	(167.8)	195.3	—	(165.1)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	67.1	45.1	—	—	112.2
Income tax (provision) benefit	(41.5)	(18.6)	—	—	(60.1)
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	25.6	26.5	—	—	52.1
Net income from discontinued operations, net of income tax	—	—	—	107.3	107.3
NET INCOME (LOSS)	$25.6	$26.5	$—	$107.3	$159.4
Identifiable assets	$7,937.0	$182.2	$—	$1,289.7	$9,408.9
Cash capital expenditures	$1,488.6	$25.1	$—	$88.9	$1,602.6
Accrued capital expenditures	$1,467.2	$24.6	$—	$85.6	$1,577.4

Note 15 – Quarterly Financial Information (unaudited)

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

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
	(in millions, except per share amounts)				
2015					
Revenues(1)	$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)
Non-recurring items in operating income (loss) (3)	(50.5)	24.0	(2.1)	(22.4)	(51.0)
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)
2014					
Revenues(1)	$827.6	$850.0	$858.5	$757.1	$3,293.2
Operating income (loss)	140.8	(35.9)	115.1	(1,067.3)	(847.3)
Income (loss) from continuing operations	12.7	(106.1)	153.7	(469.8)	(409.5)
Discontinued operations, net of income taxes (2)	27.0	13.8	17.4	1,135.7	1,193.9
Net income (loss)	39.7	(92.3)	171.1	665.9	784.4
Non-recurring items in operating income (loss) (3)	0.4	(202.5)	(11.9)	$(1,077.8)	(1,291.8)
Per share information					
Basic EPS from continuing operations	$0.07	$(0.59)	$0.85	$(2.62)	$(2.28)
Basic EPS from discontinued operations	0.15	0.08	0.10	6.34	6.64
Diluted EPS from continuing operations	0.07	(0.59)	0.84	(2.62)	(2.28)
Diluted EPS from discontinued operations	0.15	0.08	0.10	6.34	6.64

(1)In the fourth quarter of 2015, the Company determined that certain purchased oil transactions that had been included in "Revenues" on a gross basis should have been reported net, as the transactions were with the same counterparty and were entered into in contemplation of one another. The revisions had no effect on the Company's operating income, net income or earnings per share. See Note 1 – Summary of Significant Accounting Policies for additional information. The following tables detail the impact to Revenues of the revisions to the Consolidated Statement of Operations for the quarters presented.

	2015								
	First Quarter			Second Quarter			Third Quarter		
	As Reported	As Adjusted	Change	As Reported	As Adjusted	Change	As Reported	As Adjusted	Change
	(in millions)								
Revenues	$491.6	$468.1	$(23.5)	$608.6	$574.6	$(34.0)	$536.7	$507.6	$(29.1)

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	2014					
	First Quarter			Second Quarter		
	As Reported	As Adjusted	Change	As Reported	As Adjusted	Change
	(in millions)					
Revenues	$817.5	$827.6	$10.1	$887.2	$850.0	$(37.2)

	2014					
	Third Quarter			Fourth Quarter		
	As Reported	As Adjusted	Change	As Reported	As Adjusted	Change
	(in millions)					
Revenues	$910.0	$858.5	$(51.5)	$799.6	$757.1	$(42.5)

(2) In December 2014, QEP completed the Midstream Sale. QEP Field Services' financial results (excluding results of Haynesville Gathering) have been reflected as discontinued operations and all prior periods have been reclassified.

(3) Includes net gains and losses from asset sales and losses due to asset impairments.

Note 16 – Supplemental Oil and Gas Information (unaudited)

The Company is making the following supplemental disclosures of oil and gas producing activities, in accordance with ASC 932, Extractive Activities - Oil and Gas, as amended by ASU 2010-03, Oil and Gas Reserve Estimation and Disclosures, and SEC Regulation S-X. The Company uses the successful efforts accounting method for its oil and gas exploration and development activities. 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,	
	2015	2014
	(in millions)	
Proved properties	$13,314.9	$12,278.7
Unproved properties, net	691.0	825.2
Total proved and unproved properties	14,005.9	13,103.9
Accumulated depreciation, depletion and amortization	(6,870.2)	(6,153.0)
Net capitalized costs	$7,135.7	$6,950.9

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 $127.6 million and ARO additions and revisions of $21.0 million during the year ended December 31, 2015. The costs incurred to advance the development of reserves that were classified as proved undeveloped were approximately $811.3 million in 2015, $796.7 million in 2014, and $645.9 million in 2013.

	Year Ended December 31,		
	2015	2014	2013
	(in millions)		
Proved property acquisitions	$49.6	$465.4	$31.6
Unproved property acquisitions	39.8	496.3	9.3
Exploration (capitalized and expensed)	8.7	23.6	14.6
Development	1,010.3	1,695.1	1,440.8
Total costs incurred	$1,108.4	$2,680.4	$1,496.3

Results of Operations

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

	Year Ended December 31,		
	2015	2014	2013
	(in millions)		
Revenues	$1,390.4	$2,374.6	$1,901.2
Production costs	654.1	735.6	583.3
Exploration expenses	2.7	9.9	11.9
Depreciation, depletion and amortization	870.8	984.4	954.2
Impairment	55.6	1,143.2	93.0
Total expenses	1,583.2	2,873.1	1,642.4
Income (loss) before income taxes	(192.8)	(498.5)	258.8
Income tax benefit (provision)	70.6	182.5	(96.3)
Results of operations from producing activities excluding allocated corporate overhead and interest expenses	$(122.2)	$(316.0)	$162.5

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 compliance oversight of a multi-functional reserves review committee responsible to the Company's Board of Directors. QEP Energy's estimated proved reserves have been prepared by Ryder Scott Company, L.P. and DeGolyer and MacNaughton, independent reservoir engineering consultants, 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 Energy's proved undeveloped reserves at December 31, 2015, are scheduled to be developed within five years from the date such locations were initially disclosed as proved undeveloped reserves; however, long-term development of gas reserves in Pinedale is governed by the Bureau of Land Management's September 2008, Record of Decision (ROD) on the Final Supplemental Environmental Impact Statements. Under the ROD, QEP Energy is allowed to drill and complete wells year-round in designated concentrated development areas. The ROD contains additional requirements and restrictions on the sequence of development, which requires the Company to develop its leasehold from the south to the north. These restrictions result in protracted, phased development that is beyond the control of the Company. 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, 2015, 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 gas, oil and NGL reserves for the years ended December 31, 2013, 2014 and 2015 are as follows:

	Gas (Bcf)	Oil (MMbbl)	NGL (MMbbl)	Total (Bcfe)
Balance at December 31, 2012	2,622.4	119.0	99.9	3,936.1
Revisions of previous estimates[1]	(288.3)	1.3	(8.0)	(328.5)
Extensions and discoveries[2]	455.6	38.3	16.4	783.8
Purchase of reserves in place	1.0	1.9	0.2	13.4
Sale of reserves in place	(16.9)	(1.7)	(1.1)	(33.9)
Production	(218.9)	(10.2)	(4.8)	(309.0)
Balance at December 31, 2013	2,554.9	148.6	102.6	4,061.9
Revisions of previous estimates[3]	27.1	(4.0)	1.4	11.3
Extensions and discoveries[4]	141.4	16.8	8.6	294.1
Purchase of reserves in place[5]	72.5	35.7	12.3	360.7
Sale of reserves in place[6]	(299.4)	(7.5)	(21.5)	(473.4)
Production	(179.3)	(17.1)	(6.8)	(322.7)
Balance at December 31, 2014	2,317.2	172.5	96.6	3,931.9
Revisions of previous estimates[7]	(463.8)	(47.0)	(55.3)	(1,077.9)
Extensions and discoveries[8]	467.7	85.6	21.8	1,111.9
Purchase of reserves in place[9]	3.2	2.0	0.6	18.7
Sale of reserves in place[10]	(34.3)	(0.4)	(0.2)	(37.6)
Production	(181.1)	(19.6)	(4.7)	(326.8)
Balance at December 31, 2015	2,108.9	193.1	58.8	3,620.2
Proved developed reserves				
Balance at December 31, 2012	1,531.7	47.4	49.3	2,111.9
Balance at December 31, 2013	1,406.3	71.8	52.8	2,154.0
Balance at December 31, 2014	1,288.4	99.3	52.2	2,197.5
Balance at December 31, 2015	1,245.3	109.7	34.4	2,109.4
Proved undeveloped reserves				
Balance at December 31, 2012	1,090.7	71.6	50.6	1,824.2
Balance at December 31, 2013	1,148.6	76.8	49.8	
Balance at December 31, 2014	1,028.8	73.2	44.4	1,734.4
Balance at December 31, 2015	863.6	83.4	24.4	1,510.8

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(1) Revisions of previous estimates in 2013 include positive impacts due to 80.0 Bcfe pricing revisions, negative performance revisions of 265.5 Bcfe, 42.0 Bcfe negative operating cost revisions and 101.0 Bcfe other negative revisions. Pricing revisions were primarily due to increased gas prices, which increased reserves by 68.4 Bcfe. Negative performance revisions were driven by a 129.5 Bcfe decrease in Pinedale reserves and 112.7 Bcfe decrease in Haynesville reserves related to reserve adjustments based on additional production history, well performance and current pricing causing a revised future development plan, which includes lower density drilling and a change in well spacing assumptions in some areas.

(2) Extensions and discoveries in 2013 increased proved reserves by 783.8 Bcfe, primarily related to extensions and discoveries in the Williston Basin of 217.6 Bcfe, in Pinedale of 265.3 Bcfe, and 175.9 Bcfe in Haynesville. Extension and discoveries in Pinedale and Haynesville relate to certain less densely spaced wells with higher estimates of recoverable oil and gas, which were booked to replace wells removed from the Company's reserves through negative revisions caused by a change in well spacing assumptions in these areas. Of these extensions and discoveries, 687.6 Bcfe related to new PUD locations.

(3) Revisions of previous estimates in 2014 include 248.5 Bcfe negative performance revisions partially offset by positive other revisions of 197.7 Bcfe, operating cost revisions of 39.2 Bcfe and pricing revisions of 22.9 Bcfe. Negative performance revisions were driven by a 194.0 Bcfe 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 deducts. Pricing revisions were primarily due to increased gas prices, which increased reserves by 21.9 Bcfe.

(4) Extensions and discoveries in 2014 increased proved reserves by 294.1 Bcfe, primarily related to extensions and discoveries in Pinedale of 133.6 Bcfe and the Williston Basin of 123.3 Bcfe. All of these extensions and discoveries related to new well completions and the associated new PUD locations as part of the Company's development drilling plans and new compression well projections in Pinedale.

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

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

(7) Revisions of previous estimates in 2015 include: 756.9 Bcfe of negative revisions due to lower pricing and 403.2 Bcfe of negative revisions unrelated to pricing, partially offset by 82.2 Bcfe of positive performance revisions. Negative pricing revisions were driven by lower gas, oil, and NGL prices. Negative other revisions included operating in ethane rejection in Pinedale and Uinta Basin.

(8) Extensions and discoveries in 2015 increased proved reserves by 1,111.9 Bcfe, primarily related to extensions and discoveries in Williston Basin of 409.3 Bcfe, Uinta Basin of 318.9 Bcfe, and Permian Basin of 297.8 Bcfe. All of these extensions and discoveries related to new well completions and the associated new PUD locations as part of the Company's development drilling plans and new compression well projections in Pinedale.

(9) Purchase of reserves in place in 2015 related to the acquisition of additional interests in QEP's operated wells in the Williston Basin as discussed in Note 2 – Acquisitions and Divestitures.

(10) 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.

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

Future net cash flows were calculated at December 31, 2015, 2014 and 2013, 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 2015, 2014 and 2013, 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,		
	2015	2014	2013
Average benchmark price per unit:			
Gas price (per MMBtu)	$2.59	$4.35	$3.67
Oil price (per bbl)	50.28	94.99	96.94

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 booked proved undeveloped reserves are approximately $438.9 million in 2016, $472.8 million in 2017 and $306.8 million in 2018. The scheduled PUD development costs are reduced from historical levels in conjunction with our efforts to reduce drilling and completion activities, gain operational efficiencies, slow production growth and preserve liquidity in the current commodity price environment. 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 availability under its 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,		
	2015	2014	2013
	(in millions)		
Future cash inflows	$15,325.3	$28,167.3	$24,805.7
Future production costs	(7,389.9)	(9,842.1)	(8,400.3)
Future development costs	(2,202.5)	(3,521.3)	(4,056.7)
Future income tax expenses	(1,169.3)	(4,304.0)	(3,284.6)
Future net cash flows	4,563.6	10,499.9	9,064.1
10% annual discount for estimated timing of net cash flows	(2,087.3)	(5,159.9)	(4,680.2)
Standardized measure of discounted future net cash flows	$2,476.3	$5,340.0	$4,383.9

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,		
	2015	2014	2013
	(in millions)		
Balance at January 1,	$5,340.0	$4,383.9	$3,034.7
Sales of gas, oil and NGL produced during the period, net of production costs	(736.3)	(1,639.0)	(1,317.9)
Net change in sales prices and in production (lifting) costs related to future production	(6,307.8)	726.6	1,236.3
Net change due to extensions, discoveries and improved recovery	1,765.7	979.9	2,230.7
Net change due to revisions of quantity estimates	(1,350.2)	35.9	(709.6)
Net change due to purchases of reserves in place	29.7	695.3	36.8
Net change due to sales of reserves in place	(48.8)	(1,153.7)	(73.2)
Previously estimated development costs incurred during the period	865.0	867.5	722.7
Changes in estimated future development costs	560.7	409.6	(596.5)
Accretion of discount	752.9	597.3	402.2
Net change in income taxes	1,554.4	(600.3)	(601.7)
Other	51.0	37.0	19.4
Net change	(2,863.7)	956.1	1,349.2
Balance at December 31,	$2,476.3	$5,340.0	$4,383.9

Note 17 – Subsequent Event

Effective January 1, 2016, QEP terminated its contracts for resale and marketing transactions between its wholly owned subsidiaries, QEP Marketing and QEP Energy. As a result, QEP Energy will market its own gas, oil and NGL production. In addition, substantially all of QEP Marketing's third-party purchase and sale agreements and gathering, processing and transportation contracts have been assigned to QEP Energy, except those contracts related to natural gas storage activities and Haynesville Gathering. The change in affiliate transactions will simplify our business processes and financial statements by eliminating the majority of intercompany transactions. QEP also conducted a segment analysis in accordance with ASC Topic 280, Segment Reporting, and based on the changes discussed above, determined that QEP has one reportable segment after January 1, 2016. The elimination of the affiliate transactions has no impact to historical net income. However, since revenues and expenses were historically reported gross for working interest owner products in accordance with principal-agent considerations, QEP will report lower resale revenue and expenses in future periods. The remaining third party resale activity will be reported in “Other revenues” and "Gathering and other expense" on the Consolidated Statement of Operations.

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, 2015. Based on such evaluation, such officers have concluded that, as of December 31, 2015, 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

There were no changes in the Company's internal controls over financial reporting that occurred during the quarter ended December 31, 2015, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Assessment of Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act 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, 2015, 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, 2015. 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, 2015, 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

Our Board of Directors approved amendments to QEP's bylaws, which became effective on February 22, 2016. The amendments changed cross-references, numbering, and placement of certain existing provisions, and made consistent use of defined terms and other stylistic alterations. In addition, Section 2.7(E) of the bylaws was amended to delete a provision regarding the election of directors by plurality vote and to add a provision regarding the required vote for matters other than the election of directors, which were retained and deleted, respectively, in error when the bylaws were amended in October 2014 to require that directors be elected by majority vote in uncontested elections. The amendments to the bylaws had no effect on the existing rights of QEP shareholders. The amended and restated bylaws are attached as an exhibit to this Annual Report on Form 10-K.

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 17, 2016, which the Company expects to file with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2015 (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 February 22, 2016 (filed herewith)
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	6.05% Notes due 2016 (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8 K, filed with the Securities and Exchange Commission on May 15, 2006)
4.3	Officers' Certificate setting forth the terms of the 6.05% Notes due 2016 (incorporated by reference to Exhibit 99.3 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on May 15, 2006)
4.4	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)
4.5	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)
4.6	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)
4.7	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)
4.8	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)
4.9	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)
4.10	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)
4.11	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, dated as of February 25, 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, Amended and Restated, effective as of August 1, 2014 (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 6, 2014), as amended and restated by the Deferred Compensation Plan for Directors, Amended and Restated, effective as of February 23, 2015 (incorporated by reference to Exhibit 10.6 to the Company's Annual Report on Form 10-K/A, filed with the Securities and Exchange Commission on February 25, 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 and restated by Cash Incentive Plan, Amended and Restated, 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 26, 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 and restated by Long-Term Stock Incentive Plan, Amended and Restated, 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 26, 2015)
10.9+	Executive Severance Compensation Plan effective as of March 1, 2012 (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 16, 2012), as amended and restated by the Executive Severance Compensation Plan - CIC, effective as of February 23, 2014 (incorporated by reference to Exhibit 10.9 to the Company's Annual Report on Form 10-K, filed with the Securities and Exchange Commission on February 25, 2014), and the Executive Severance Compensation Plan, Amended and Restated, effective October 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 October 26, 2015)
10.10+	Amended Deferred Compensation Wrap Plan, adopted January 28, 2013 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on January 31, 2013), as amended and restated by the Amended 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 adopted June 12, 2010 (incorporated by reference to Exhibit 10.12 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange

	Commission on June 16, 2010), as amended and restated by the Amended 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 26, 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 26, 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 26, 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	Purchase and Sale Agreement, dated August 23, 2012, by and among QEP Energy Company, as purchaser, and Helis Oil & Gas Company, L.L.C., as seller (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 30, 2012)
10.21	Purchase and Sale Agreement, dated August 23, 2012, by and among QEP Energy Company, as purchaser, and Black Hills Exploration and Production, Inc., Unit Petroleum Company, Sundance Energy, Inc., Highline Exploration, Inc., Houston Energy, L.P., Nisku Royalty, LP, Empire Oil Company and Kent M. Lynch, as sellers (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 30, 2012)
10.22	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)
10.23	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)
10.24+	Basic Executive Severance Compensation Plan, dated effective as of January 20, 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 January 23, 2014)
10.25+	

	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)
10.26+	QEP Midstream Partners, LP 2013 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on November 5, 2013)
10.27+	Form of QEP Midstream Partners, LP 2013 Long-Term Incentive Plan Phantom Unit Award Agreement (incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on November 5, 2013)
10.28+	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)
10.29+	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)

10.30	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)
10.31	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)
10.32	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)
10.33	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)
10.34	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)
10.35	Guaranty, dated December 2, 2014, by QEP Resources, Inc. in favor of Tesoro Logistics LP (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 December 4, 2014)
10.36+	Form of Performance Share Unit Award Agreement under the QEP Resources, Inc. Cash Incentive Plan, for awards to executive officers through 2014 (incorporated by reference to Exhibit 10.41 to the Company's Annual Report on Form 10-K, filed with the Securities and Exchange Commission on February 24, 2015)
10.37+	Form of Performance Share Unit Award Agreement under the QEP Resources, Inc. Cash Incentive Plan, for awards to executive officers after 2014 (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)
10.38+	Form of Performance Share Unit Award Agreement under the QEP Resources, Inc. Cash Incentive Plan, effective October 26, 2015 (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 October 26, 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.
99.2*	Qualifications and Report of Independent Petroleum Engineers and Geologists - DeGolyer and MacNaughton
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 Schedule:
QEP RESOURCES, INC.
Schedule of Valuation and Qualifying Accounts

Description	Beginning Balance	Amounts charged (credited) to expense	Deductions for accounts written off and other		Ending Balance
	(in millions)				
Year ended December 31, 2015					
Allowance for bad debts	$4.6	$0.5	$(1.2	)	$3.9
Year ended December 31, 2014					
Allowance for bad debts	2.2	2.1	0.3		4.6
Year ended December 31, 2013					
Allowance for bad debts	2.4	0.1	(0.3	)	2.2

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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 24, 2016.

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 24, 2016.

/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 24, 2016	*By	/s/ Charles B. Stanley Charles B. Stanley, Attorney in Fact