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

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2012

001-34778
(Commission File No.)

QEP Resources, Inc.

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

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

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (Section 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

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

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter (June 30, 2012): $5,327,744,063.

At January 31, 2013, there were 178,551,744 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 2013 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 Securities and Exchange Commission (SEC). Prior to QEP's Spin-off from Questar Corporation (described in more detail in Item 1 of Part I of this Annual Report on Form 10-K), QEP's predecessor, Questar Market Resources, Inc., filed annual, quarterly and current reports with the SEC. QEP also regularly files proxy statements and other documents with the 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 1-800-SEC-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 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 the Company's 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 500, Denver, CO 80265 (telephone number: 1-303-672-6900).

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, and Section 21E of the Securities Exchange Act of 1934, as amended. 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:

- QEP's growth strategies;
- natural gas, oil and NGL prices and factors affecting the volatility of such prices;
- plans to drill or participate in wells and to defer completion of wells;
- results from planned drilling operations and production operations;
- amount and allocation of forecasted capital expenditures and plans for funding capital expenditures and operating expenses;
- plans to divest of assets, including plans to separate portions of gathering assets into a master limited partnership;
- estimated reserves;
- estimated accruals for loss contingencies and other items;
- impact of lower commodity prices;
- effect of recession;
- plans to enter into derivative contracts for a portion of forecasted production;
- future expenses and operating costs;
- the ability to secure long-term gathering, processing and treating contracts from third parties as required to fully utilize the Company's midstream assets;
- operation of the Company's Blacks Fork II and other processing plants at assumed capacities;
- the amount and timing of the settlement of derivative contracts;
- incurrence of unrealized derivative gains and losses;
- the ability of QEP to use derivative instruments to manage commodity price risk and the availability to the Company of the end-user exemption under Title VII of the Dodd-Frank Act;
- impact of nonperformance by trade creditors or joint venture partners;

- the outcome of contingencies such as legal proceedings;
- impact on earnings from discontinuing hedge accounting;
- expected contributions to the Company's pension plans;
- impact of recently issued accounting pronouncements;
- QEP's ability to develop reserves and grow production as necessary to satisfy delivery commitments and our ability to purchase natural gas, crude oil and NGL in the market to cover any shortfalls;
- conversion of proved undeveloped reserves to proved developed reserves;
- the significance of Adjusted EBITDA as a measure of cash flow and liquidity;
- payment of dividends;
- potential for future asset impairments;
- estimated future purchase accounting adjustments;
- maintaining an appropriate debt rating; and
- future activist efforts.

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 discussed in Part I, Item 1A of this Annual Report on Form 10-K;
- changes in natural gas, oil and NGL prices;
- general economic conditions, including the performance of financial markets and interest rates;
- drilling results;
- shortages of oilfield equipment, services and personnel;
- lack of available pipeline capacity;
- QEP's inability to successfully integrate acquired assets or dispose of non-core assets;
- the outcome of contingencies such as legal proceedings;
- permitting delays;
- operating risks such as unexpected drilling conditions;
- weather conditions;
- changes in maintenance and construction costs, including possible inflationary pressures;
- the availability and cost of debt and equity financing;
- changes in laws or regulations, including the implementation of the Dodd-Frank Act;
- climate change and other initiatives related to drilling and completion techniques, including hydraulic fracturing;
- derivative activities;
- substantial liabilities from legal proceedings and environmental claims;
- failure of internal controls and procedures;
- elimination of federal income tax deductions for oil and gas exploration and development costs;
- future opportunities that QEP's board of directors may determine present greater potential value to stockholders than planned divestiture of assets;
- regulatory approvals and compliance with contractual obligations;
- failure to obtain court approval or class member acceptances of settlement agreement for the Company's class action lawsuit;
- actions, or inaction, by federal, state, local or tribal governments; 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 website to reflect future events or circumstances. All such statements are expressly qualified by this cautionary statement.

Glossary of Terms

Adjusted EBITDA Adjusted EBITDA is a non-GAAP financial measure. Management defines Adjusted EBITDA as net income before the following items: separation costs, accrued litigation loss contingency, depreciation, depletion and amortization, exploration expense, abandonment and impairment, gains and losses from asset sales, unrealized gains and losses on derivative contracts, interest and other income, loss on early extinguishment of debt, interest expense, income taxes and discontinued operations.

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. 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.

cryogenic processing Utilizes refrigeration by reducing gas pressure across a turbo expander that reduces the gas temperature to 100 degrees below zero Fahrenheit.

cushion gas Volume of gas that must remain in a natural gas storage facility to provide the required pressure to extract the stored or working gas volumes.

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 4-10(a)(6).

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

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 An exploratory well is 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.

frac spread The difference between the market value for natural gas liquids (NGL) extracted from the natural gas stream and the market value of the Btu-equivalent volume of natural gas required to replace the extracted liquids.

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

gross "Gross" natural gas and crude oil wells or "gross" acres are the total number of wells or acres in which the Company has a working interest.

IFNPCR Inside the Federal Energy Regulatory Commission (FERC) monthly settlement index for the Northwest Pipeline Corporation Rocky Mountains.

IFPEPL Inside FERC monthly settlement index for the Panhandle Eastern Pipeline Company.

keep-whole processing Processing contracts where the Company retains and sells NGL extracted at its processing plants and keeps the customer "whole" by buying and delivering a Btu-equivalent amount of natural gas to the customer.

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" gas and oil wells or "net" acres are determined by the sum of the fractional ownership working interest the Company has in the gross wells or acres.

NYMEX The New York Mercantile Exchange.

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

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

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

proved properties Properties with proved reserves.

proved reserves Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. See 17 C.F.R. Section 4-10(a)(22).

reserves Estimated remaining quantities of natural gas, crude oil and related substances anticipated to be economically producible 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. See 17 C.F.R. Section 4-10(a)(26).

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

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

royalty An interest in a gas and oil 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 4-10(a)(31).

working interest An interest in a gas and oil 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 2012
PART I

ITEM 1. BUSINESS

Nature of Business

QEP Resources, Inc. (QEP or the Company), is a holding company with three major lines of business: natural gas and crude oil exploration and production; midstream field services; and energy marketing. These businesses are conducted through the Company's three principal subsidiaries:

- QEP Energy Company (QEP Energy) acquires, explores for, develops and produces natural gas, crude oil, and natural gas liquids (NGL);
- QEP Field Services Company (QEP Field Services) provides midstream field services, including natural gas gathering, processing, compression and treating services for affiliates and third parties; and
- QEP Marketing Company (QEP Marketing) markets affiliate and third-party natural gas and crude oil, and owns and operates an underground natural gas storage reservoir.

QEP operates in the Northern and Southern Regions of the United States and is headquartered in Denver, Colorado. Principal offices are located in Denver, Colorado; Salt Lake City, Utah; and Tulsa, Oklahoma.

Reincorporation Merger and Spin-off from Questar

Effective May 18, 2010, Questar Market Resources Inc. (Market Resources), then a wholly owned, public subsidiary of Questar Corporation (Questar), merged with and into a newly formed, wholly owned subsidiary, QEP Resources, Inc., a Delaware corporation, in order to reincorporate in the State of Delaware (Reincorporation Merger). The Reincorporation Merger was effected pursuant to an Agreement and Plan of Merger entered into between Market Resources and QEP. On June 30, 2010, Questar distributed all of the shares of common stock of QEP held by Questar to Questar shareholders in a tax-free, pro rata dividend (the Spin-off). Each Questar shareholder received one share of QEP common stock for each share of Questar common stock held at the close of business on the record date. In connection with the Spin-off, QEP distributed Wexpro Company (Wexpro), a wholly owned subsidiary of QEP at the time, to Questar. In addition, Questar contributed $250.0 million of equity to QEP prior to the Spin-off.

In connection with the reorganization, QEP renamed its subsidiaries as follows:

- QEP Energy Company (formerly Questar Exploration and Production Company);
- QEP Field Services Company (formerly Questar Gas Management Company); and
- QEP Marketing Company (formerly Questar Energy Trading Company).

The financial information presented in this Annual Report on Form 10-K presents QEP's financial results as an independent company separate from Questar and reflects Wexpro's financial condition and operating results as discontinued operations for all periods presented. A summary of discontinued operations can be found in Note 13 - Discontinued Operations, to the consolidated financial statements in Item 8 of Part II this Annual Report on Form 10-K.

Financial and Operating Highlights

Our financial and operating highlights for 2012 include:

- Generated net income of $128.3 million, or $0.72 per diluted share, a decrease of 52%, due primarily to the accrual of a litigation loss contingency of $115.0 million;
- Generated Adjusted EBITDA (a non-GAAP financial measure defined and reconciled in Item 7 of Part II of this Annual Report on Form 10-K) of $1,415.5 million, up from $1,386.6 million in 2011;
- Increased total production by 16% to 319.2 Bcfe and liquids (oil and NGL) production by 80% to 69.9 Bcfe;
- Increased total proved reserves 9% to 3.9 Tcfe and increased liquid (oil and NGL) proved reserves by 52% to 1.3 Tcfe;
- Added 572.5 Bcfe of proved reserves from extensions and discoveries;
- Acquired $1.4 billion of assets in QEP's existing core acreage in the Williston Basin, North Dakota;
- Increased Field Services gathering throughput volumes, NGL sales volumes and fee-based processing volumes by 2%, 3% and 4%, respectively; and

- Issued $1.15 billion of senior notes and entered into a $300 million five-year term loan.

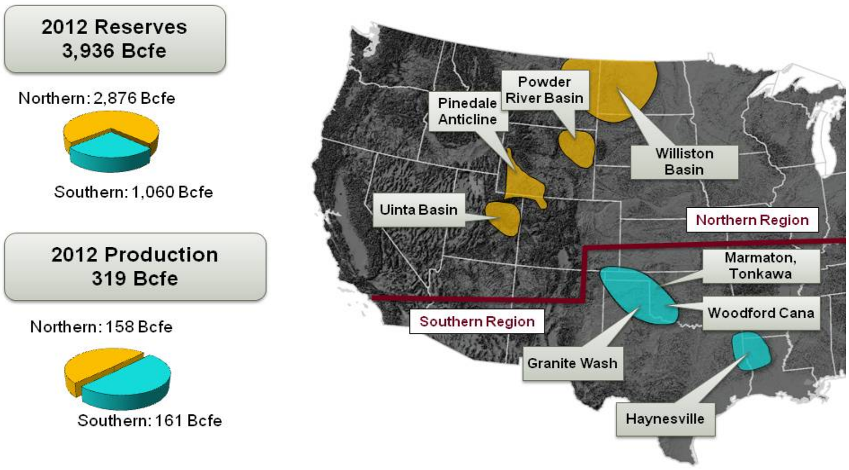
Strategies

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

- operate in a safe and environmentally responsible manner;
- allocate capital to those projects that generate optimal returns;
- acquire businesses and assets that complement or expand our current business;
- maintain a sustainable, diverse inventory of low cost, high-margin resource plays;
- be in 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;
- own a controlling interest in and operate midstream infrastructure in our core producing areas to capture value downstream of the wellhead;
- build gas processing plants to extract liquids from our natural gas streams;
- gather, compress and treat our production to drive down costs;
- support the growth of our midstream business with the intention of forming a Master Limited Partnership;
- actively market our QEP Energy production to maximize value;
- utilize derivative contracts to mitigate the impact of natural gas, crude oil or NGL price volatility, while locking in acceptable cash flows required to support future capital expenditures;
- attract and retain the best people; and
- maintain a capital structure that allows us the necessary financial flexibility with which to invest in organic growth and potential acquisition opportunities, as they may arise.

Exploration and Production – QEP Energy Company

QEP Energy is actively involved in several of North America's most important hydrocarbon resource plays. QEP Energy has a large inventory of identified development drilling locations, primarily on the Pinedale Anticline in western Wyoming; the Williston Basin in North Dakota; the Haynesville/Cotton Valley in northwestern Louisiana; the Uinta Basin in eastern Utah; Anadarko Basin in Oklahoma and Texas and other proven properties in Wyoming, Colorado and Utah. For 2013, QEP plans to allocate approximately 91% of its capital budget to QEP Energy. The following map illustrates the location of the Company's significant exploration and production activities, our Northern and Southern Regions described elsewhere in this report, and related reserve and production data as of December 31, 2012:



QEP's exploration and production activities are conducted through QEP Energy, which generated approximately 80%, 76%, and 81% of the Company's Adjusted EBITDA (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 the years ended December 31, 2012, 2011 and 2010, respectively. QEP Energy operates in two core regions – the Northern Region (including the states of Wyoming, Utah, Colorado, New Mexico and North Dakota) and the Southern Region (including the states of Oklahoma, Texas and Louisiana). The Northern Region contributed 49% of 2012 production while the Southern Region contributed 51%. QEP Energy reported 3,936 Bcfe of estimated proved reserves as of December 31, 2012, up from 3,614 Bcfe at the end of 2011. Of those estimated proved reserves, approximately 74%, or 2,876 Bcfe, were located in the Northern Region at December 31, 2012, compared to 64% or 2,312 Bcfe at December 31, 2011. The remaining 26%, or 1,061 Bcfe, were located in the Southern Region at December 31, 2012, compared to 36% or 1,302 Bcfe at December 31, 2011. Approximately 54% of the proved reserves reported by QEP Energy at year end 2012 were developed. Approximately 33% of the total proved reserves at December 31, 2012, were comprised of crude oil and NGL up from 24% at December 31, 2011.

During the third quarter of 2012, QEP Energy acquired oil and gas properties in the Williston Basin for an aggregate purchase price of $1.4 billion, subject to post-closing adjustments (the 2012 Acquisition). The acquired properties consist of approximately 27,600 net acres of producing and undeveloped oil and gas properties in the active play area for the Bakken and Three Forks Formations within the Williston Basin. The acquired properties added 313.8 Bcfe of proved reserves during 2012.

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

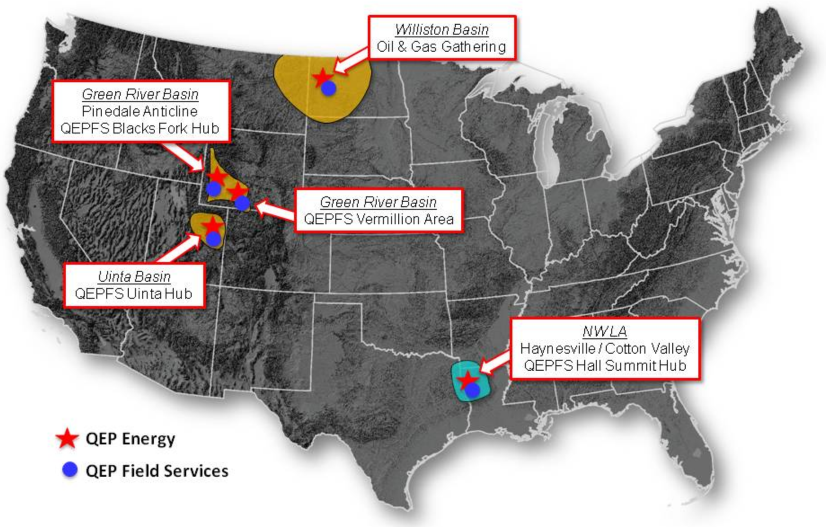
The Company seeks to acquire, develop and produce natural gas and oil from resource plays in its core areas. Since the existence and distribution of hydrocarbons in resource plays is well understood, development of these accumulations has lower risk than conventional discrete hydrocarbon accumulations. Resource plays typically require many wells, drilled at high density, to fully develop and produce the hydrocarbon accumulations. Development of QEP Energy's resource play accumulations requires expertise in drilling large numbers of complex, highly deviated or horizontal wells to vertical depths that 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. QEP Energy also continues to conduct some exploratory drilling to determine the commerciality of its inventory of unproven leaseholds. QEP Energy seeks to maintain geographical and geological diversity with its two core regions. The Company has in the past and may in the future pursue acquisition of producing properties through the purchase of assets or corporate entities in order to expand its presence in its core areas or to create new core areas.

QEP Energy, both directly and through QEP Marketing, sells its natural gas, crude oil and NGL production to a variety of customers, including gas-marketing firms, industrial users, local-distribution companies, crude oil refiners and remarketers. QEP Energy regularly evaluates counterparty credit and may require financial guarantees or prepayments from parties that fail to meet its credit criteria.

Midstream Field Services – QEP Field Services Company

QEP owns midstream (gathering, processing and treating) systems to complement its exploration and production operations in most of the regions where QEP Energy has production. Through ownership and operation of these facilities, QEP is able to better manage the timing and costs associated with bringing on new production and enhance the value received for its products by gathering, processing and treating the Company's production. In addition, QEP's midstream business also provides midstream services to third-party customers, including major and independent producers. QEP generates revenues from its midstream activities through a variety of agreements including fee-based gathering, processing and keep-whole processing agreements. For 2013, QEP plans to allocate approximately 7% if its capital budget to QEP Field Services to grow its midstream business, including completing the construction of its gathering system in the Uinta Basin as well as the 10,000 Bbl/d expansion of the NGL fractionator located at the Blacks Fork processing complex (expected to be completed in the second half of 2013).

The following map illustrates QEP Field Services' areas of operations and the locations corresponding with QEP Energy's operating areas:



QEP Field Services generated approximately 20%, 23% and 18% of the Company's Adjusted EBITDA (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) in the years ended December 31, 2012, 2011 and 2010, respectively. QEP Field Services owns various natural gas gathering, treating and processing facilities in the Northern and Southern Regions as well as 78% of Rendezvous Gas Services, LLC (RGS), a partnership that operates gas gathering facilities in western Wyoming. RGS gathers natural gas for the Pinedale Anticline and the Jonah Field producers for delivery to various interstate pipelines. QEP Field Services also owns 38% of Uintah Basin Field Services, LLC (UBFS) and 50% of Three Rivers Gathering, LLC (Three Rivers). These two partnerships operate natural gas gathering facilities in eastern Utah. The Rendezvous Pipeline Co., LLC (Rendezvous Pipeline), a wholly owned subsidiary of QEP Field Services, operates a Federal Energy Regulatory Commission (FERC) regulated, 21-mile, 20-inch-diameter gas transmission pipeline between QEP Field Services' Blacks Fork gas processing plant and the Muddy Creek compressor station owned by Kern River Gas Transmission Co. (Kern River Pipeline).

Fee-based gathering and processing revenues represented 77%, 70% and 78% of QEP Field Services' net operating revenues (revenues less plant shrink and transportation costs) during the years ended December 31, 2012, 2011 and 2010, respectively. Approximately 41%, 35%, and 36% of QEP Field Services' 2012, 2011 and 2010 net gas processing revenues (processing revenues less plant shrink) were derived from fee-based processing agreements. The remaining revenues were derived from keep-whole processing agreements. A keep-whole contract exposes QEP Field Services to frac-spread risk while a fee-based contract eliminates direct commodity price exposure. To further reduce volatility associated with keep-whole contracts, QEP Field Services may enter into forward-sales contracts for NGL or NGL price derivatives and equivalent gas volume derivatives with the intent to lock in a processing margin.

QEP Field Services faces regional competition with varying competitive factors in each basin. QEP Field Services' gathering and processing business competes with interstate and intrastate pipelines, producers and independent gatherers and processors. Numerous factors impact a customer's choice of a gathering or processing service provider, including rate, location, term, pressure obligations, timeliness of services, and contract structure. QEP Field Services provides natural gas gathering, processing and treating services to affiliates and third-party producers who own producing natural gas fields in the Rocky Mountain region, the Williston Basin and in northwest Louisiana. In addition to its natural gas operations, QEP Field Services also provides crude oil and water gathering and handling to affiliates and third-party producers in the Rocky Mountain region and the Williston Basin. QEP Field Services' gas gathering, processing and treating services are generally provided under long-term agreements.

Energy Marketing—QEP Marketing Company

QEP Marketing provides wholesale marketing and sales of affiliate and third-party natural gas, oil and NGL and generated less than 1% of the Company's Adjusted EBITDA (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) in all of the years ended December 31, 2012, 2011 and 2010. As a wholesale marketing entity, QEP Marketing concentrates on markets in the Rocky Mountains and Midcontinent 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 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 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 QEP Energy's natural gas and volumes purchased from third parties to wholesale marketers, industrial end-users and utilities. QEP Marketing sells QEP Energy's crude oil volume to refiners, remarketers and other companies, including some with pipeline facilities near company producing properties. QEP Marketing sells NGL volumes from its Clear Creek storage facility to a refiner. In the event pipeline facilities are not available, QEP Marketing arranges transportation of crude oil by truck or rail to storage, refining or pipeline facilities.

Government Regulation

QEP's business operations are subject to regulation under a wide range of local, state, tribal and federal statutes, rules, orders and regulations. The regulatory burden on the oil and gas industry increases the cost of doing business and consequently affects its profitability. While QEP believes that it is in substantial compliance 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 the Company, 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 Item 1A - Risk Factors, in this Annual Report on Form 10-K.

Regulation of Exploration, Production, Gathering and Processing Activities
The regulation of oil and gas exploration and production is a broad and increasingly complex area, notably including laws and regulations governing the discharge or release of materials into the environment or otherwise relating to environmental protection. These laws and regulations include 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 Energy in its business, including but not limited to engines, tanks, dehydrators and gas processing plant components.

Greenhouse Gases Regulations and Climate Change Legislation. The Environmental Protection Agency (EPA) published its findings that emissions of carbon dioxide, methane, and other greenhouse gases (GHG) present an endangerment to 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 adopted regulations for the measurement and reporting of GHG emitted from certain large facilities. In November 2010, the EPA expanded its GHG Reporting Rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis. In addition, both houses of Congress have considered legislation in recent years to reduce emissions of GHG, and a number of states have already taken legal measures to reduce emissions of GHG, primarily through the development of GHG inventories, greenhouse gas permitting and/or regional GHG cap and trade programs.

Clean Water Act and Safe Drinking Water Act. The Clean Water Act and similar state laws regulate discharges of wastewater, oil, and other pollutants to surface water bodies, such as lakes, rivers, wetlands, and streams, as well as discharges to storm water. 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 or release of water produced or used during oil and gas development.

Oil Pollution Act of 1990. The Oil Pollution Act of 1990 (OPA) and regulations issued under OPA impose strict, joint and several liability on "responsible parties" for removal costs and damages 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 that contributed to the release of a "hazardous substance" 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 and liability for failure to meet such 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 crude oil, natural 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 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 and shale reservoirs require hydraulic fracture stimulation to achieve economic production rates and recoverable reserves. The majority of the Company'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 comprised 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. The Company does not use diesel fuel in any of its fracturing operations. The Company supports disclosure of 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).

The Company obtains water for fracture stimulations from a variety of sources including industrial water wells and surface water sources. When technically and economically feasible, the Company recycles flow-back and produced water, which reduces water consumption from surface and groundwater sources and reduces produced water disposal volumes. The Company believes that the employment of fracture stimulation technology does not present any significant additional risks other than the risks generally associated with natural gas and oil 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 natural gas and oil well design and operation. Additionally, the Bureau of Land Management (BLM) proposed in May 2012 new regulations regarding chemical disclosure requirements and other regulations specific to well stimulation activities, including hydraulic fracturing, on federal and tribal land. There has been a heightened debate recently over whether the fluids used in hydraulic fracturing may contaminate drinking water supplies, and proposals have been made to revisit the environmental exemption for hydraulic fracturing under the SDWA or to enact separate federal legislation or legislation at the state and local government levels that would regulate hydraulic fracturing.

The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices and a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with final results expected to be available by 2014. Moreover, the EPA announced in October 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a publicly owned treatment plant. In addition, the Department of Energy is conducting an investigation of practices the agency could recommend to better protect the environment from drilling employing hydraulic fracture stimulation.

Additionally, a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices, and recent Congressional legislative efforts seek to regulate hydraulic fracturing under the SDWA's Underground Injection Control program, which would significantly increase well capital costs. Certain members of Congress have also called upon (1) the Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; (2) the Securities and Exchange Commission (SEC) to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing; and (3) the Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. Air quality impacts from hydraulic fracturing practices are also being studied currently by various federal and state agencies. These various ongoing or proposed studies and investigations, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA, the Clean Air Act or other statutes and regulatory programs. The Company supports disclosure of the contents of hydraulic fracturing fluids, and submits information regarding its wells to the national online disclosure registry, FracFocus (www.fracfocus.org).

Tribal Lands and Minerals. Various federal agencies within the U.S. Department of the Interior, particularly the BLM and the Bureau of Indian Affairs, along with certain Native American tribes, promulgate and enforce regulations pertaining to natural gas and oil operations on Native American tribal lands on which QEP Energy operates. These regulations include such matters as lease provisions, drilling and production requirements, environmental standards and royalty considerations.

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 currently.

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 facilities to disseminate information on chemical inventories to employees as well as local emergency planning committees and emergency response departments. The Non-Government Organization Environmental Integrity Project has filed a petition for rulemaking with the EPA under the EPCRA and the federal Administrative Procedure Act to add the "Oil and Gas Extraction Industry" to the list of industries required to report releases of certain "toxic chemicals" under EPCRA's Toxics Release Inventory (TRI) program. 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.

Dodd-Frank Wall Street Reform and Consumer Protection Act. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was passed by Congress and signed into law in July 2010. The 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 a potential exemption from these clearing and cash collateral requirements for commercial end-users. In addition, in August 2012, the SEC issued a final rule under Section 1504 of the Dodd-Frank Act, Disclosure of Payments by Resource Extraction Issuers, which requires resource extraction issuers, such as QEP, to file annual reports that provide information about the type and total amount of payments made for each project related to the commercial development of oil, natural gas, or minerals to each foreign government and the federal government.

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.

Other Regulations. QEP Field Services' construction and operation activities are subject to various local, state, federal and tribal rules and regulations. Most of these rules and regulations are administered by the Department of Transportation, the Occupational Safety and Health Administration, and the EPA.

Regulation of Transportation of Crude Oil by Pipeline

The Interstate Commerce Act (ICA), as applied to liquids pipelines, requires that rates and terms of service be just and reasonable and non-discriminatory. Under the ICA, FERC regulates the rates and terms and conditions of service for interstate movements of crude oil, natural gas liquids and refined petroleum products.

Regulation of Underground Storage

QEP through Clear Creek Storage Company, LLC, 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.

Significant Customers

The Company's five largest customers accounted for 37%, 32%, and 27% in aggregate, of QEP revenues during the years ended December 31, 2012, 2011 and 2010, respectively. During the year ended December 31, 2012, Chevron U.S.A. Inc. and Enterprise Products Operating, L.P. accounted for 13% and 10%, respectively, of the Company's total revenues. Management believes that the loss of either customer, 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 years ended December 31, 2011 and 2010, each of the five largest customers sales were below 10% of QEP's total revenues.

Employees

At December 31, 2012, QEP Resources, Inc. had 936 employees compared to 876 employees at December 31, 2011. None of QEP's employees are represented by unions or covered by collective bargaining agreements.

Executive Officers of the Registrant

The name, age, period of service, title and business experience of each of QEP's executive officers as of February 19, 2013, are listed below:

Charles B. Stanley	54	Chairman (2012 to present), President, and Chief Executive Officer, QEP (2010 to present). Previous titles with Questar: 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	54	Executive Vice President, Chief Financial Officer, and Treasurer QEP (2010 to present). Previous titles with Questar: 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).
Jay B. Neese	54	Executive Vice President, QEP (2010 to present). Previous titles with Questar: Senior Vice President (2005 to 2010); Executive Vice President, Market Resources and Market Resources subsidiaries (2005 to 2010); Vice President, Market Resources and Market Resources subsidiaries (2003 to 2005); Assistant Vice President (2001 to 2003).
Austin S. Murr	59	Senior Vice President - Land and Business Development (2012 to present). Vice President - Land and Business Development (2010 - 2012). Previous titles with Questar: Vice President - Land and Business Development (2006 - 2010); Director of Business Development (2004 to 2006).
Perry H. Richards	52	Senior Vice President – Field Services (2010 to present). Previous title with Questar: Vice President, Questar Gas Management (2005 to 2010).
Jim E. Torgerson	49	Senior Vice President - Operations (2012 to present). Previous title with QEP: Senior Vice President, Drilling and Completions (2011 to 2012). Previous titles with Questar: Vice President, Drilling and Completions (2009 to 2010); Vice President, Rockies Drilling and Completions (2005 to 2008).
Abigail L. Jones	52	Vice President, Compliance and Corporate Secretary, QEP (2010 to present). Previous titles with Questar: Vice President Compliance (2007 to 2010); Corporate Secretary (2005 to 2010); Assistant Secretary (2004 to 2005).
Christopher K. Woosley	43	Vice President and General Counsel (2012 to present). Previous title with QEP: 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 Fiala	49	Vice President - Human Resources (2010 to present). Prior to joining QEP, Ms. Fiala held a variety of roles at Suncor Energy (1995 to 2010) and most recently was the Director of Human Resources for Suncor Energy U.S.A. (2004 to 2010).

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 the officers were selected.

ITEM 1A. RISK FACTORS

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 actually occur, the Company's business, financial condition or results of operations could be materially adversely affected.

The prices for natural gas, oil and NGL are volatile, and a decline in such prices could adversely affect QEP's results, stock price and growth plans. Historically natural gas, oil and NGL prices have been volatile and will likely continue to be volatile in the future. U.S. natural gas prices in particular are significantly influenced by weather and weather forecasts. Any significant or extended decline in commodity prices would impact the Company's future financial condition, revenue, operating results, cash flow, return on invested capital, and rate of growth. In addition, significant and extended declines in commodity prices could limit QEP's access to sources of capital or cause QEP to delay or postpone some of its capital projects. Because a significant portion of QEP Energy's future production is natural gas, the Company's financial results are substantially more sensitive to changes in natural gas prices than to changes in oil prices.

QEP cannot predict the future price of natural gas, oil and NGL because of factors beyond its control, including but not limited to:

- changes in domestic and foreign supply of natural gas, oil and NGL;
- changes in local, regional, national and global demand for natural gas, oil, NGL and related commodities;
- the activities of the Organization of Petroleum Exporting Countries;
- domestic and global economic conditions;
- regional price differences resulting from available pipeline transportation capacity or local demand;
- terrorist attacks on production or transportation assets;
- the level of imports of, and the price of, foreign natural gas, oil and NGL;
- the potential long-term impact of an abundance of natural gas, oil and NGL from unconventional sources on the global and local energy supply;
- domestic political developments and actions;
- weather conditions and weather forecasts;
- domestic government regulations and taxes, including regulations or legislation relating to climate change or natural gas and oil 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 for fuel for electricity generation;
- storage levels of natural gas, oil, and NGL; and
- the quality of natural gas and oil produced.

In addition, lower commodity prices may result in asset impairment charges from reductions in the carrying values of QEP's natural gas and oil properties or a reduction in the carrying value of goodwill. During the years ended December 31, 2012 and 2011, QEP recorded impairment charges of $107.6 million and $195.5 million, respectively, on its proven properties and $23.7 million and $20.3 million, respectively, on its unproven properties. See Part I, Item 8, Note 1 - Summary of Significant Accounting Policies, of this Annual Report on Form 10-K for additional information.

Slower economic growth rates in the U.S. may materially adversely impact QEP's operating results. The U.S. and other economies are recovering from a global financial crisis and recession that began in 2008. Growth has resumed but has been modest and at an unsteady rate. There could be significant long-term effects resulting from the financial crisis and recession, including a future global economic growth rate that is slower than that experienced in the years leading up to the crisis, and more volatility may occur before a sustainable, yet lower, growth rate is achieved. In addition, the Organization for Economic Cooperation and Development has encouraged countries with large federal budget deficits, such as the U.S., to initiate deficit reduction measures. Such measures, if they are undertaken too rapidly, could further undermine economic recovery and slow growth by reducing demand. Global economic growth drives demand for energy from all sources, including fossil fuels. A lower future economic growth rate is likely to result in decreased demand growth for QEP's natural gas, oil and NGL production. A decrease in demand, excluding changes in other factors, could potentially result in lower commodity prices, which would reduce QEP's 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 natural gas, oil and NGL, but also its ability to find, develop and acquire gas and oil reserves that are economically recoverable. Producing natural gas and oil reservoirs are generally characterized by declining production rates that vary depending on reservoir characteristics. Because natural gas and oil production volumes from QEP 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 gas and oil reserves to replace those depleted by production.

Gas and oil reserve estimates are imprecise and subject to revision. QEP's proved natural gas and oil reserve estimates are prepared annually by independent reservoir engineering consultants. Gas and oil 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 also 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 is reflective of the current market value of the estimated natural gas and oil 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.

Shortages of, and increasing prices for, oilfield equipment, services and qualified personnel could impact results of operations. 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 fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. There have also been regional shortages of drilling rigs and other equipment, as demand for specialized rigs and equipment has increased along with the number of wells being drilled. These factors also cause increases in costs for equipment, services and personnel. These cost increases could impact profit margin, cash flow and operating results or restrict the ability to drill wells and conduct operations, especially during periods of lower natural gas and oil prices.

QEP's operations involve numerous risks that might result in accidents and other operating risks and costs. Drilling of natural gas and oil wells is potentially a high-risk activity. Risks include:

- injuries and/or deaths of employees, supplier personnel, or other individuals;
- fire, explosions and blow-outs;
- unexpected drilling conditions such as abnormally pressured formations;
- pipe, cement or casing failures;
- title disputes;
- equipment malfunctions and/or mechanical failure on high-volume wells;
- security breaches, cyber attacks, piracy, or terroristic acts;
- theft or vandalism of oilfield equipment and supplies, especially in areas of increased activity;
- severe weather that could affect our operations;
- plant, pipeline, and other facility accidents and failures; and
- environmental accidents such as oil spills, natural gas leaks, ruptures or discharges of air pollutants, brine water or well fluids into the environment, including from hydraulic fracturing activities.

The Company 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 attorney's fees and other expenses incurred in the prosecution or defense of litigation. As a working interest owner in wells operated by other companies, the Company may also be exposed to the risks enumerated above from operations that are not within its care, custody or control.

There are also inherent operating risks and hazards in the Company's gas and oil production and gas gathering, processing and treating operations that could cause substantial financial losses. These risks could result in personal injury or loss of human life, significant damage to property, environmental pollution, impairment of operations and substantial losses. The location of pipelines near populated areas, including residential areas, commercial business centers and industrial sites could increase the level of damages resulting from these risks. Certain segments of the Company's pipelines run through such areas. In spite of the Company's precautions, an accident or other event could cause considerable harm to people or property, and could have a material adverse effect on the financial position and results of operations, particularly if the event is not fully covered by insurance. Accidents or other operating risks once realized could further result in lost business activity. Such circumstances could adversely impact the Company's ability to meet contractual obligations.

As is customary with industry practice, operators generally indemnify 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 the relative fault of the contractor. Therefore, QEP may be liable, regardless of the fault of the contractor, 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 as well as for claims for personal injury or death suffered by QEP's employees and others. QEP's drilling contracts and oilfield service agreements, however, generally provide that the contractor will indemnify QEP for claims related to injury and death of employees of the contractor and its subcontractors and for property damage suffered by the contractor and its contractors.

As is also customary in the gas and oil industry, the Company 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.

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 natural gas and oil 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, natural gas and oil 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.

Lack of availability of pipeline and other transportation capacity could impact results of operations. The lack of availability of satisfactory oil, natural gas and NGL transportation facilities may hinder QEP's access to oil, NGL and natural gas markets or delay production from its wells. QEP's ability to market its production depends in substantial part on the availability and capacity of pipelines 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, or other reasons. If pipelines do not exist near producing wells, if pipeline capacity is limited or if pipeline capacity is unexpectedly disrupted, sales could be reduced or production shut in, reducing profitability. Furthermore, if QEP were required to shut in wells, it might also be obligated to pay 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. If pipeline quality requirements change, QEP might be required to install or contract for additional treating or processing equipment, which could also increase costs. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could also adversely affect QEP's ability to transport natural gas and oil.

The fees charged by QEP to third parties under its gathering and processing agreements may not escalate sufficiently to cover increases in costs, or the agreements may not be renewed or may be suspended in some circumstances. QEP's costs may increase at a rate greater than the fees it charges to third parties for gathering, treating and processing services. Furthermore, third parties may not renew their contracts with QEP. Additionally, some third parties' obligations under their agreements with QEP may be permanently or temporarily reduced due to certain events, some of which are beyond QEP's control, including force majeure events wherein the supply of either natural gas, oil or NGL are curtailed or cut off. Force majeure events include (but are not limited to): revolutions, wars, acts of enemies, embargoes, import or export restrictions, strikes, lockouts, fires, storms, floods, earthquakes, acts of God, explosions and mechanical or physical failures of equipment affecting QEP's facilities or facilities of third parties. If the escalation of fees is insufficient to cover increased costs, if third parties do not renew or extend their contracts with QEP or if third parties suspend or terminate their contracts with QEP, the Company's financial results would suffer.

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 natural gas and oil 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 financings 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 natural 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. The Company utilizes its revolving credit facility, provided by a group of financial institutions, to meet short-term funding needs. All of QEP's debt under its revolving credit facility is floating-rate debt. 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 or construction of new oil and gas processing facilities, which in turn could lead to a possible reduction in QEP's natural gas or oil production, reserves and its revenues, and could negatively impact its results of operations.

A downgrade in QEP's credit rating could negatively impact QEP's cost of and ability to access capital. Although QEP is not aware of any current plans of credit rating agencies to lower their ratings on QEP's debt, QEP's credit ratings may be subject to future downgrades. A downgrade of credit ratings may make it more difficult or expensive to raise capital from financial institutions or other sources. A downgrade in QEP's credit rating below a certain level could limit the amount of debt that QEP may incur. In addition, a downgrade could affect QEP's requirements to provide financial assurance of its performance under certain contractual arrangements and derivative agreements.

QEP's debt and other financial commitments may limit its financial and operating flexibility. QEP's total debt was approximately $3.2 billion at December 31, 2012. 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, to pay dividends to shareholders, 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 agreements governing QEP's revolving credit facility and term loan facility contain a number of covenants that impose constraints on the Company, including restrictions on QEP's ability to dispose of assets, make certain investments, and incur liens.

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, joint interest and working interest owners as well as customers in all segments of its business. Because QEP is the operator of a majority of its production and major development projects, QEP pays joint venture expenses and in some cases makes cash calls on its non-operating partners for their respective shares of joint venture costs. These projects are capital intensive and, in some cases, a non-operating partner may experience a delay in obtaining financing for its share of the joint venture costs. Counterparty liquidity problems could result in a delay 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 parties. 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 faces various risks associated with the trend toward increased activism against 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, gathering or processing facilities;
- 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;
- increased severance and/or other taxes;
- cyber attacks;
- legal challenges or lawsuits;
- negative publicity about QEP;
- increased costs of doing business;
- reduction in demand for QEP's products; and
- other adverse effects on QEP's ability to develop its properties and increase production.

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

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 natural 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 margining 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 into QEP's income. This 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 enters into commodity-price derivative arrangements with creditworthy counterparties (banks and energy-trading firms) that do not require collateral deposits. QEP is exposed to the risk of counterparties not performing. The amount of credit available may vary depending on QEP's counterparty's assessment of QEP's credit risk.

Relative changes in NGL and natural gas prices may adversely impact QEP's results due to changes in the frac spread. Approximately 23%, 30% and 22% of QEP Field Services' net operating revenues for the years ended December 31, 2012, 2011 and 2010, respectively, were derived from keep-whole processing agreements. Under QEP's keep-whole processing contracts, QEP is exposed to the frac spread and transportation and fractionation exposure from firm transportation constraints. Generally, the frac spread and, consequently, the net operating margins are positive under these contracts. In the event natural gas becomes more expensive on a Btu equivalent basis than NGL products, QEP's cost of keeping the producer "whole" would result in operating losses. Due to timing of gas purchases and liquid sales, direct exposure to changes in market prices of either gas or liquids can be created, because there is an offsetting purchase or sale that remains exposed to market pricing. Through QEP's marketing and derivatives activity, direct exposure may occur naturally or QEP may choose direct price exposure to either gas or liquids when QEP favors that exposure over frac spread risk. Given that QEP has derivative positions, adverse movement in prices to the positions QEP has taken will negatively impact results.

QEP has made significant investments in new cryogenic gas processing plants in its Northern Region (Rockies) in recent years. The expected returns on these investments depend in large part on the future ethane price and margin, which historically have been more volatile than the price of other NGL products, including propane, butane and gasoline. QEP's competitors have also made significant investments in gas processing plants that recover significant volumes of ethane. The U.S. ethane market is currently oversupplied, and probably will remain oversupplied in the foreseeable future, resulting in lower ethane prices.

QEP's plans to grow its midstream business by constructing new processing and treating facilities subjects the Company to construction risks and the risk that the Company will not be able to secure long-term contracts from third parties required to earn acceptable returns on these investments. One of the ways QEP has grown its business is through the construction of new gathering, treating and processing facilities. The construction of gathering, treating and processing facilities requires the expenditure of significant amounts of capital and involves numerous regulatory, environmental, political, legal and inflationary uncertainties. If QEP undertakes these projects, QEP may not be able to complete them on schedule, or at all, or at the budgeted cost. While QEP may commit natural gas supplies from its production, such supplies may not be sufficient to fill available capacity at these facilities, leaving QEP with limited natural gas supplies committed to these facilities prior to and after their construction. Moreover, QEP may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. QEP may also rely on estimates of proved reserves in its decision to construct new facilities, which may prove to be inaccurate, because there are numerous uncertainties inherent in estimating quantities of proved reserves. As a result, new facilities may not be able to process or treat enough natural gas to achieve QEP's expected investment return, which could adversely affect QEP's operations and cash flows.

If QEP's plan to separate a majority of its gathering assets in Wyoming and North Dakota into a new publicly traded master limited partnership is delayed or not completed, QEP's stock price may decline and its growth potential may not be enhanced. In January 2013, QEP announced a plan to separate a majority of its gathering assets in Wyoming and North Dakota into a new publicly traded master limited partnership (“MLP”) and to file an initial registration statement in connection with this planned initial public offering in the second quarter of 2013. Completion of this plan is subject to market conditions and numerous other risks beyond QEP's control, including, but not limited to, the general economy, credit markets, equity markets, energy prices, regulatory approvals, compliance with contractual obligations, and future opportunities that QEP's board of directors may determine present greater potential value to stockholders than the planned MLP. Therefore, it is possible that QEP will not file a registration statement for an initial public offering, that the MLP will not complete an offering of securities, and that QEP will not be able to complete its proposed actions on the desired timetable. If the transaction is not completed or delayed, QEP's stock price may decline and its growth potential may not be enhanced. If completed, QEP's plan to separate portions of gathering assets may not achieve its intended results. QEP's announcement of this plan did not, and this risk factor does not, constitute an offer to sell or the solicitation of an offer to buy any securities and shall not constitute an offer, solicitation or sale in any jurisdiction in which such offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of that jurisdiction.

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 natural gas and oil 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 natural 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 natural gas and crude oil 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. 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 2012 Acquisition in the Williston Basin. This may present greater risks for QEP than those faced by peer companies that do not consider acquisitions as a part of their business strategy. QEP cannot provide assurance that it will be able to identify acquisition opportunities. Even if QEP does identify 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.

QEP may be unable to dispose of non-core, non-strategic assets on financially attractive terms, resulting in reduced cash proceeds and/or losses. 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 the 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 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 liability 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 must be 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, or injunctions that could limit the scope of QEP's planned operations.

Current federal regulations restrict activities during certain times of the year on significant portions of QEP Energy leasehold due to wildlife activity and/or habitat. QEP Energy 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. Various wildlife species inhabit QEP Energy's leaseholds at Pinedale and in other areas. The presence of wildlife or plants, including species that are protected under the federal Endangered Species Act, could limit access to leases held by QEP Energy on public and other lands. 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 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 natural gas resources in the Pinedale Anticline Project Area (PAPA). Under the ROD, QEP Energy is allowed to drill and complete wells year-round in one of five Concentrated Development Areas defined in the PAPA. The ROD contains additional requirements and restrictions on development of the PAPA to which QEP Energy is subject.

Several of QEP Field Services' transportation facilities are subject to FERC jurisdiction, and as such, are subject to specific regulations regarding interstate transmission facilities and activities, including but not limited to rates charged for transmission, open access/non-discrimination, and public daily capacity and flow reporting requirements. Additionally, FERC has jurisdiction over the operation of QEP Marketing's Clear Creek storage facility by virtue of the facility being connected 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 charges for transmission, open access/non-discrimination, and public disclosure via an electronic bulletin board of daily capacity and flows.

Section 1(b) of the Natural Gas Act exempts gathering activities from regulation or jurisdiction by the FERC. QEP owns, or holds interests in, a number of pipelines that it believes meet the tests FERC has used to determine a pipeline system's status as a non-jurisdictional gatherer. There is, however, no bright-line test for determining jurisdictional status of QEP Field Services' gathering systems, so the distinction between non-jurisdictional gathering and FERC-regulated transmission pipelines may from time-to-time be the subject of disputes and litigation. QEP Field Services therefore cannot guarantee that the jurisdictional status of its gathering systems will remain unchanged. QEP's gas gathering systems are not currently subject to state utility regulations. The FERC has jurisdiction under the Energy Policy Act of 2005 to impose rules and regulations applicable to all natural gas market participants to ensure market transparency.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation. The U.S. President's Fiscal Year 2013 Budget Proposal includes provisions that, if enacted into law, would eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include (i) the repeal of the percentage depletion allowance for oil and natural gas wells, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. 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 this legislation 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 natural gas exploration and development and increase the cost of exploration and development of natural gas and oil resources.

Environmental laws are complex and potentially burdensome for QEP's operations. QEP must comply with numerous and complex federal, state and tribal 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 natural gas and oil 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. Requirements imposed by these authorities may be costly and time consuming and may result in delays in the commencement or continuation of the Company's exploration and production and midstream field services operations. For example, QEP's drilling operations in the Powder River Basin in Wyoming continue to be delayed due to an over two-year backlog of permit applications. 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.

Federal and state hydraulic fracturing legislation or regulatory initiatives could increase QEP's costs and restrict its access to natural gas and oil reserves. Currently, all well construction activities, including hydraulic fracture stimulation, are regulated by state agencies that review and approve all aspects of natural gas and oil well design and operation. The EPA recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the federal SDWA and has begun the process of drafting guidance documents 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, the Bureau of Land Management proposed in May 2012, new regulations regarding chemical disclosure requirements and other regulations specific to well stimulation activities, including hydraulic fracturing, on federal and tribal lands. 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.

QEP's ability to produce natural gas and oil 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 it uses 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 natural gas and oil requires the use and disposal of significant quantities of water. 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. As noted above, 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 natural 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 and cause delays, interruptions or termination of its operations, the extent of which cannot be predicted.

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 natural 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 natural gas and crude oil. QEP's ability to access and develop new natural gas and crude oil 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. Additionally, the EPA and authorized states have begun the permitting of major sources of GHG under the Clean Air Act pursuant to the EPA's GHG Tailoring Rule whereby new and existing sources of GHG emitting above major source thresholds are required to obtain major source permits. In addition, several of the states in which QEP operates are considering various GHG registration and reduction programs. While additional climate-change regulation is possible at the federal level, it is too early to predict how such regulation would affect QEP's business, operations or financial results. 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 that may or may not be the result of 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.

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 passed by Congress and signed into law in July 2010, contains significant derivatives regulation. QEP is currently evaluating the final rules of the Commodity Futures Trading Commission and assessing the impact on the Company's risk management program. QEP believes it will meet the requirements for the commercial end-user clearing exception and be able to continue to execute derivative transactions and not be required to meet the mandated clearing requirements.

QEP will need to expend significant resources complying with and adapting to the new regulatory regime, including significant reporting and record keeping requirements, as well as otherwise ensuring that QEP continues to be able to rely on certain exemptions from mandatory clearing requirements. In addition, the changes to the swap market as a result of the implementation of the Dodd-Frank Act could significantly increase the cost of entering into new swaps or maintaining existing swaps, materially alter the terms of new or existing swap transactions, impose additional documentation requirements, and/or reduce the availability of new or existing swaps.

Depending on the final form of the margin rules for uncleared swaps and whether swap dealers elect to collect margin from end-user clients even if there is no requirement to do so under the Dodd-Frank Act, QEP might in the future be required to provide cash collateral for its commodity derivative transactions under circumstances in which it does not currently post cash collateral. Requirements to post cash collateral could not only cause significant liquidity issues by reducing QEP's flexibility in using its cash and other sources of funds, such as its revolving credit facility, but could also cause QEP to incur additional debt. In addition, a requirement for QEP's counterparties to post cash collateral would likely result in additional costs being passed on to QEP, thereby decreasing the effectiveness of its commodity derivatives and its profitability. If the costs of complying with the clearing and margin requirements and business conduct rules under the Dodd-Frank Act significantly increase the costs of entering into commodity derivative transactions, QEP may reduce its commodity derivative program, which could increase its exposure to fluctuating commodity prices, increase the volatility of QEP's results of operations and reduce the predictability of the Company's cash flows, which in turn could adversely affect QEP's ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices. QEP's revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on QEP's consolidated financial position, results of operations or cash flows.

General economic and other conditions impact QEP's results. QEP's results may also be negatively affected by: changes in global economic conditions; availability and economic viability of gas and oil 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 defined benefit pension plan that covers 145, or 16%, of QEP's active employees and 70 participants that are retired, terminated and vested, or suspended. 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, 2012 and 2011, QEP's pension plans were underfunded by $74.4 million and $59.9 million, respectively. The underfunded status of QEP's pension plans may require that the Company make large contributions to such plans. QEP made cash contributions of $6.9 million and $14.8 million during the years ended December 2012 and 2011, respectively, to its defined benefit pension plans and expects to make contributions of approximately $11.3 million to its pension plans in 2013. 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 subject 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 and processing 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. QEP's technologies, systems, networks, and those of its vendors, suppliers and other business partners may become the target of cyber attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of its business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. QEP's systems and insurance coverage for protecting against cyber security risks may not be sufficient.

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 core regions – the Northern Region (including the states of Wyoming, Utah, Colorado, New Mexico and North Dakota) and the Southern Region (including the states of Oklahoma, Texas and Louisiana).

Northern Region

Pinedale
In 2005, the Wyoming Oil and Gas Conservation Commission (WOGCC) approved 10-acre density drilling for Lance Pool wells on about 12,700 gross acres (8,091 net acres) of QEP Energy's 17,115 gross acres (11,601 net acres) Pinedale leasehold. In January 2008, the WOGCC approved five-acre density drilling for Lance Pool wells on about 4,200 gross acres (2,677 net acres) of QEP Energy's Pinedale leasehold. On March 13, 2012, the WOGCC approved five-acre density drilling for Lance Pool wells on approximately 7,200 additional gross acres (4,317 net acres). The area approved for increased density corresponds to the currently estimated economic productive limits of QEP Energy core acreage in the field. The top of the Lance Pool tight gas sand reservoir interval ranges from 8,500 to 9,500 feet across QEP Energy's acreage. The Company currently estimates that more than 900 additional wells will be required to fully develop its Pinedale acreage on 5 to 10-acre density. At December 31, 2012, QEP Energy had four operated rigs drilling in the Pinedale Anticline. In addition to QEP Energy's 715 gross producing wells, QEP Energy has an overriding royalty interest only in an additional 21 wells at Pinedale.

Williston Basin
QEP has approximately 117,000 net acres of leaseholds in the Williston Basin in western North Dakota, where the Company is targeting the Bakken and Three Forks formations. During the third quarter of 2012, QEP Energy closed the 2012 Acquisition, which added 27,600 net acres of producing leasehold in the Williston Basin. As a result of the 2012 Acquisition and development drilling on existing acreage, Williston Basin reserves represent 16% of the Company's total reserves. Accordingly, Williston Basin reserves and production are shown separately from Legacy's results in the years presented. The top of the Bakken Formation ranges from approximately 9,500 feet to 10,000 feet across QEP Energy's leasehold. The Three Forks Formation lies approximately 60 to 70 feet below the Middle Bakken Formation and is also a target for horizontal drilling. As of December 31, 2012, QEP Energy had five operated rigs drilling in the Williston Basin.

Uinta Basin
The majority of Uinta Basin proved reserves are found in a series of vertically stacked, laterally discontinuous reservoirs at depths of 4,500 feet to deeper than 18,000 feet. QEP Energy owns working interests in approximately 257,000 net leasehold acres in the Uinta Basin. QEP Energy had three operated rigs drilling in the Uinta Basin at December 31, 2012, two of which were targeting the Lower Mesaverde Formation productive fairway in the Red Wash Unit, in which QEP holds 32,300 net acres, and the other drilling various vertical and horizontal oil targets.

Legacy
The remainder of QEP Energy Northern Region leasehold interests, productive wells and proved reserves are distributed over a number of fields and properties managed as Legacy. Exploration and development activity in 2012 included wells in the Powder River and Greater Green River Basins in Wyoming.

Southern Region

Haynesville/Cotton Valley
QEP Energy has approximately 50,700 net acres of Haynesville Shale leaseholds in northwest 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 below the Hosston and Cotton Valley formations that QEP Energy has been developing in northwest Louisiana since the 1990's. As of December 31, 2012, due to depressed natural gas prices, QEP Energy did not have any operated rigs drilling in the Haynesville/Cotton Valley area.

Midcontinent
QEP Energy's Midcontinent operations cover all properties in the Southern Region except the Haynesville/Cotton Valley area of northwest Louisiana and are distributed over a large area, including the Anadarko Basin of Oklahoma and the Texas Panhandle.

QEP Energy has approximately 76,000 net acres of Woodford "Cana" Shale leaseholds in western Oklahoma. The top of the Woodford Shale ranges from approximately 10,500 feet to 14,500 feet across QEP Energy's leasehold. As of December 31, 2012, QEP Energy had two operated rigs drilling in the Woodford/Cana play.

QEP Energy has approximately 35,000 net acres of Granite Wash/Atoka Wash leaseholds in the Texas Panhandle and western Oklahoma and has been drilling vertical Granite Wash/Atoka Wash wells for over a decade. The top of the Granite Wash/Atoka Wash interval ranges from approximately 11,100 feet to 15,900 feet across QEP Energy's leasehold. In the past few years, QEP and other operators have drilled a number of successful horizontal wells in the Granite Wash/Atoka Wash play but have also drilled some uneconomic wells. As of December 31, 2012, QEP Energy had one rig drilling in oil and liquids-rich gas plays in the Texas Panhandle.

Reserves – QEP Energy

At both December 31, 2012 and 2011, approximately 91% of QEP Energy's estimated proved reserves were Company operated. Proved developed reserves represented 54% of the Company's total proved reserves at both December 31, 2012 and 2011, while the remaining 46% of reserves were classified as proved undeveloped at both December 31, 2012 and 2011. All reported reserves are located in the U.S. 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 as follows:

	December 31, 2012				December 31, 2011			
	Natural Gas	Oil	NGL	Natural Gas Equivalents [1]	Natural Gas	Oil	NGL	Natural Gas Equivalents [1]
	(Bcf)	(MMbbl)	(MMbbl)	(Bcfe)	(Bcf)	(MMbbl)	(MMbbl)	(Bcfe)
Proved developed reserves	**1,531.7**	**47.4**	**49.3**	**2,111.9**	1,538.3	33.0	38.4	1,966.3
Proved undeveloped reserves	**1,090.7**	**71.6**	**50.6**	**1,824.2**	1,211.1	34.6	38.2	1,647.5
Total proved reserves	**2,622.4**	**119.0**	**99.9**	**3,936.1**	2,749.4	67.6	76.6	3,613.8

(1) Oil and NGL are converted to natural gas equivalents at the ratio of one bbl 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, 2010, through December 31, 2012, is summarized below:

Year ended December 31,	Year End Reserves (Bcfe)	Natural Gas, Oil and NGL Production (Bcfe)	Reserve Life Index [1] (Years)
2010	3,030.7	229.0	13.2
2011	3,613.8	275.2	13.1
2012	**3,936.1**	**319.2**	**12.3**

(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) used 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 17 - Supplemental Gas and Oil Information (unaudited), of in Item 8 of Part II of this Annual Report 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 below:

	December 31,			
	2012		2011	
Northern Region	**(Bcfe)**	**(% of total)**	(Bcfe)	(% of total)
Pinedale	**1,530.8**	**39%**	1,531.0	42%
Williston Basin	**614.7**	**16%**	259.0	7%
Uinta Basin	**617.9**	**16%**	393.6	11%
Legacy	**112.2**	**3%**	128.6	4%
Southern Region				
Haynesville/Cotton Valley	**530.5**	**13%**	782.9	22%
Midcontinent	**530.0**	**13%**	518.7	14%
Total QEP Energy	**3,936.1**	**100%**	3,613.8	100%

Estimates of the quantity of proved reserves increased during 2012, primarily related to reserve additions in the Williston and Uinta Basins, offset by decreases in estimated Haynesville/Cotton Valley proved reserves. The increase in Williston Basin reserves was primarily the result of the 2012 Acquisition, while increases in the Uinta Basin were attributable to extensions and additions from the recognition of additional proved undeveloped locations due to QEP's increased drilling program. The Haynesville/Cotton Valley decrease was primarily related to downward pricing related revisions, resulting from lower natural gas prices mostly related to proved undeveloped reserves.

Proved Undeveloped Reserves

Significant changes to proved undeveloped reserves (PUDs) occurring during 2012, are summarized in the table below:

	2012
	(Bcfe)
Proved undeveloped reserves at January 1,	1,647.5
Transferred to proved developed reserves	(255.6)
Purchase of reserves in place	225.1
Revisions to previous estimates [1]	(283.5)
Extensions and discoveries	490.7
Proved undeveloped reserves at December 31, [2]	**1,824.2**

(1) The decrease was primarily related to downward pricing related revisions for Haynesville/Cotton Valley, resulting from lower natural gas prices.

(2) All of QEP Energy's PUDs at December 31, 2012, are scheduled to be developed within five years from the date such locations were initially disclosed as PUDs, except for 200 Bcfe of reserves located within the northern portion of the Company's Pinedale Anticline leasehold in western Wyoming. Long-term development of natural 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 require 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.

The costs incurred to continue the development of PUDs were approximately $513.0 million, $533.6 million and $434.2 million for the years ended December 31, 2012, 2011 and 2010, respectively. The costs incurred in 2012 related to the drilling of PUDs in QEP's development projects. This investment resulted in the transfer in 2012 of 255.6 Bcfe of reserves from proved undeveloped to proved developed, representing 16% of the Company's total proved undeveloped reserves as of December 31, 2011.

Estimated future development costs relating to the development of PUDs are projected to be approximately $1,042.5 million in 2013, $871.1 million in 2014 and $814.5 million in 2015. Estimated future development costs include capital spending on major development projects, some of which will take several years to complete. PUDs 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 gas and oil 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. We retained Ryder Scott Company, independent oil and gas reserve evaluation engineering consultants ("Ryder Scott"), to prepare the estimates of 100% of our proved reserves as of December 31, 2012, 2011 and 2010. The individual at Ryder Scott who was responsible for overseeing the preparation of our reserve estimates as of December 31, 2012, 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 thirty years experience in the Petroleum Industry, including experience estimating and evaluating petroleum reserves. A more detailed letter of the individual's professional qualifications has been filed as part of Exhibit 99.1 to this report.

The individual at QEP Resources responsible for insuring the accuracy of the reserve estimate preparation material provided to Ryder Scott and reviewing the estimates of reserves received from Ryder Scott is our Chief Engineer. This individual is a member of the Society of Petroleum Engineers and graduated with a Bachelors of Science degree in Geological Engineering from South Dakota School of Mines and Technology in 1979. He is a registered Professional Petroleum Engineer in the state of Colorado. This individual has over 30 years experience in the Petroleum Industry, including more than 20 years reservoir engineering experience in most of the active domestic basins in the U.S.

To establish 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 our 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 December 2012 in those cases where such data were considered to be definitive. For wells currently on 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 99% of QEP's proved developed non-producing and undeveloped reserves included in this Annual Report on Form 10-K were estimated by analogy. The remaining one percent of such reserves were estimated by the volumetric method. The volumetric analysis utilized pertinent well data furnished to Ryder Scott by QEP or obtained from available public data sources through December 2012. Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by QEP. Wells or locations that are not currently producing may start producing earlier or later than anticipated in these estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies. The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing 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 17 - Supplemental Gas and Oil 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 reserves estimates as of December 31, 2012, with the Energy Information Administration of the Department of Energy on Form EIA-23. Although QEP uses the same technical and economic assumptions when it prepares the EIA-23 as used to estimate reserves for this Annual Report on Form 10-K, it is obligated to report 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, Production Prices and Production Costs

The following table sets forth the net production volumes, the field-level prices per Mcf of natural gas, per bbl of oil and per bbl of NGL produced, and the operating expenses per Mcfe for the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31,		
	2012	2011	2010
QEP Energy			
Volumes produced and sold			
Natural gas (Bcf)	**249.3**	236.4	203.8
Oil (MMbbl)	**6,306.9**	3,741.3	2,979.8
NGL (MMbbl)	**5,349.0**	2,715.6	1,225.8
Total equivalent production (Bcfe)	**319.2**	275.2	229.0
Average field-level price [1]			
Natural gas (per Mcf)	**$ 2.68**	$ 3.95	$ 4.18
Oil (per bbl)	**84.45**	86.20	69.39
NGL (per bbl)	**34.43**	47.76	39.04
Lifting costs (per Mcfe)			
Lease operating expense	**$ 0.55**	$ 0.54	$ 0.56
Production taxes	**0.30**	0.36	0.34
Total lifting costs	**$ 0.85**	$ 0.90	$ 0.90

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

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

	Year ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
QEP Energy - Natural gas (Bcf)					
Northern Region					
Pinedale	**77.4**	69.3	65.1	**8.1**	4.2
Williston Basin	**0.9**	0.1	—	**0.8**	0.1
Uinta Basin	**16.3**	14.9	14.9	**1.4**	—
Legacy	**11.4**	12.1	13.7	**(0.7)**	(1.6)
Southern Region					
Haynesville/Cotton Valley	**112.0**	107.1	79.3	**4.9**	27.8
Midcontinent	**31.3**	32.9	30.8	**(1.6)**	2.1
Total production	**249.3**	236.4	203.8	**12.9**	32.6

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

	Year ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
QEP Energy - Oil (Mbbl)					
Northern Region					
Pinedale	**664.4**	583.8	551.8	**80.6**	32.0
Williston Basin	**3,029.5**	1,133.5	478.7	**1,896.0**	654.8
Uinta Basin	**890.9**	866.7	957.1	**24.2**	(90.4)
Legacy	**297.6**	271.0	269.5	**26.6**	1.5
Southern Region					
Haynesville/Cotton Valley	**43.4**	51.0	78.4	**(7.6)**	(27.4)
Midcontinent	**1,381.1**	835.3	644.3	**545.8**	191.0
Total production	**6,306.9**	3,741.3	2,979.8	**2,565.6**	761.5

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

	Year ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
QEP Energy - NGL (Mbbl)					
Northern Region					
Pinedale	**3,054.3**	1,099.6	—	**1,954.7**	1,099.6
Williston Basin	**197.1**	29.5	3.9	**167.6**	25.6
Uinta Basin	**371.1**	106.4	121.5	**264.7**	(15.1)
Legacy	**100.1**	100.5	97.9	**(0.4)**	2.6
Southern Region					
Haynesville/Cotton Valley	**8.5**	8.4	5.5	**0.1**	2.9
Midcontinent	**1,617.9**	1,371.2	997.0	**246.7**	374.2
Total production	**5,349.0**	2,715.6	1,225.8	**2,633.4**	1,489.8

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

	Year ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
QEP Energy - Total Production (Bcfe)					
Northern Region					
Pinedale	**99.7**	79.4	68.5	**20.3**	10.9
Williston Basin	**20.3**	7.1	2.9	**13.2**	4.2
Uinta Basin	**23.9**	20.8	21.4	**3.1**	(0.6)
Legacy	**13.7**	14.2	15.8	**(0.5)**	(1.6)
Southern Region					
Haynesville/Cotton Valley	**112.3**	107.5	79.8	**4.8**	27.7
Midcontinent	**49.3**	46.2	40.6	**3.1**	5.6
Total production	**319.2**	275.2	229.0	**44.0**	46.2

Northern Region

Pinedale

Net production from the Pinedale Anticline, located in western Wyoming, grew 26% to 99.7 Bcfe during 2012, compared to the year earlier. Net production from Pinedale grew 16% to 79.4 Bcfe during 2011, compared to a year earlier. Pinedale production growth in 2012 and 2011 was driven by increased drilling activity over that period and the fee-based processing agreement at Blacks Fork II entered into in the third quarter of 2011 between QEP Energy and QEP Field Services. As a result of the processing agreement, QEP Energy's NGL production at Pinedale during 2012, was 3,054.3 Mbbl, contrasted with 1,099.6

Mbbl in the comparable 2011 period. During the years ended December 31, 2012, 2011 and 2010, Pinedale's production represented 31%, 29% and 30% of QEP Energy's total production, respectively.

Williston Basin
In the Williston Basin, production increased 186% to 20.3 Bcfe during 2012, from the year earlier, and increased 145% during 2011, compared to 2010, due to increased oil-directed drilling activity in the basin. In addition, the 2012 Acquisition contributed 5.2 Bcfe of increased production in the fourth quarter 2012. During the years ended December 31, 2012, 2011 and 2010, Williston Basin production represented 6%, 3% and 1% of QEP Energy's total production, respectively.

Uinta Basin
In the Uinta Basin, which is located in eastern Utah, production increased 15% to 23.9 Bcfe during 2012 due to increased drilling activity in the Lower Mesaverde formation in the Red Wash Unit. NGL production increased 264.7 Mbbl during 2012 compared to 2011, primarily as a result of QEP Energy executing a cryogenic, fee-based processing agreement with QEP Field Services for a portion of the Red Wash Unit's natural gas production in mid-2012. During 2011, production decreased 3% from decreased drilling activity, despite a first quarter 2011 prior-period adjustment of QEP's ownership interest within a federal unit participating area, which resulted in a positive adjustment to reported volumes of 1.6 Bcfe. During the years ended December 31, 2012, 2011 and 2010, Uinta Basin production represented 7%, 8%, and 9%, respectively, of QEP Energy's total production.

Legacy
QEP Energy's Legacy properties include all Northern Region Rockies properties except those at Pinedale, the Williston Basin and the Uinta Basin. Legacy's net production during 2012, decreased 4% to 13.7 Bcfe and decreased 10% during the year ended December 31, 2011. The decreased production was primarily due to declining production on older wells partially offset by drilling activity in the Powder River Basin. During both the years ended December 31, 2012 and 2011, Legacy's production represented 4% of QEP Energy's total production and 7% during the year ended December 31, 2010.

<u>Southern Region</u>

Haynesville/Cotton Valley
Net production from the Haynesville Shale and Cotton Valley's tight sand gas plays in northwest Louisiana increased 4% to 112.3 Bcfe during 2012 when compared to 2011. The increase in 2012 was due to the completion of several high-rate wells in early 2012 that were drilled during the latter half of 2011. QEP Energy has discontinued operated development drilling in the Haynesville Shale and Cotton Valley's tight sand gas plays in response to depressed natural gas prices. QEP Energy expects production from the Haynesville/Cotton Valley to continue to decline from its peak in the second quarter of 2012 as the last operated rig was released in July 2012. In addition, the completion of five wells that were drilled and cased in 2012 were completed in January 2013. Net production in the Haynesville/Cotton Valley area grew 35% to 107.5 Bcfe during 2011 compared to 2010, due to the Company's active drilling in the play in 2011. During the years ended December 31, 2012, 2011 and 2010, Haynesville/Cotton Valley's production comprised 35%, 39% and 35% of QEP Energy's total production, respectively.

Midcontinent
Net production in the Midcontinent grew 7% to 49.3 Bcfe during 2012 compared to 2011, driven by a 65% increase in crude oil production and an 18% increase in NGL production. Net production in the Midcontinent grew 14% to 46.2 Bcfe during 2011 compared to 2010. Midcontinent production growth in 2012 and 2011 was driven by the continued development of the Granite Wash, Marmaton and Tonkawa plays in Texas and western Oklahoma and the Woodford "Cana" Shale liquids-rich gas play in the Anadarko Basin of western Oklahoma. During the years ended December 31, 2012, 2011 and 2010, Midcontinent's production represented 15%, 17% and 18% of QEP Energy's total production, respectively.

Productive Wells

The following table summarizes the Company's productive wells as of December 31, 2012, all of which are located in the U.S.:

	Natural gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Northern Region						
Pinedale	715	450	—	—	715	450
Williston Basin	—	—	263	108	263	108
Uinta Basin	685	497	1,771	209	2,456	706
Legacy	787	248	381	133	1,168	381
Southern Region						
Haynesville/Cotton Valley	815	469	1	—	816	469
Midcontinent	2,522	763	429	98	2,951	861
Total productive wells	5,524	2,427	2,845	548	8,369	2,975

The term "gross" refers to all wells or acreage in which QEP has at least a partial working interest and the term "net" refers to QEP's ownership represented by that working interest. Although many wells produce both natural gas and oil, and many natural gas wells also have allocated NGL volumes from processing, a well is categorized as either a natural gas or an oil well based upon the ratio of gas to oil produced at the wellhead. Each gross well completed in more than one producing zone is counted as a single well. At December 31, 2012, the Company had 77 gross wells with completions in more than one reservoir.

The Company also holds numerous overriding royalty interests in oil and gas wells, a portion of which are convertible to working interests after recovery of certain costs by third parties. Once the overriding royalty interest 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, 2012. "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
Northern Region						
Colorado	158,865	106,062	103,455	30,624	262,320	136,686
Montana	33,245	10,776	343,606	62,764	376,851	73,540
New Mexico	94,169	66,433	34,689	12,714	128,858	79,147
North Dakota	97,222	42,523	214,232	85,834	311,454	128,357
South Dakota	40	40	204,798	107,551	204,838	107,591
Wyoming	272,964	159,598	351,361	247,842	624,325	407,440
Utah	191,247	147,772	221,511	140,107	412,758	287,879
Other	13,986	3,723	157,059	42,129	171,045	45,852
Southern Region					—	—
Arkansas	40,423	11,352	2,940	1,884	43,363	13,236
Kansas	32,224	13,368	52,379	17,205	84,603	30,573
Louisiana	79,652	65,103	2,205	2,165	81,857	67,268
Oklahoma	599,554	276,764	449,006	132,443	1,048,560	409,207
Texas	130,241	42,744	45,893	45,091	176,134	87,835
Other	—	—	1,757	1,300	1,757	1,300
Total	**1,743,832**	**946,258**	**2,184,891**	**929,653**	**3,928,723**	**1,875,911**

(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 natural gas and oil 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,		
2013	107,088	62,324
2014	59,538	43,584
2015	90,924	72,145
2016	35,496	32,921
2017 and later	116,851	112,614
Total	409,897	323,588

Drilling Activity

The following table summarizes the number of development and exploratory wells drilled during the years indicated:

	Developmental Wells				Exploratory Wells			
	Productive		Dry		Productive		Dry	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Year Ended December 31, 2012								
Northern Region								
Pinedale	**102.0**	**73.3**	**—**	**—**	**—**	**—**	**—**	**—**
Williston Basin	**88.0**	**28.0**	**—**	**—**	**—**	**—**	**—**	**—**
Uinta Basin	**254.0**	**45.1**	**—**	**—**	**1.0**	**0.6**	**—**	**—**
Legacy	**31.0**	**6.6**	**—**	**—**	**—**	**—**	**—**	**—**
Southern Region								
Haynesville/Cotton Valley	**35.0**	**15.7**	**—**	**—**	**2.0**	**1.6**	**—**	**—**
Midcontinent	**157.0**	**32.2**	**—**	**—**	**—**	**—**	**—**	**—**
Total	**667.0**	**200.9**	**—**	**—**	**3.0**	**2.2**	**—**	**—**
Year Ended December 31, 2011								
Northern Region								
Pinedale	105.0	71.6	—	—	—	—	—	—
Uinta Basin	176.0	6.3	—	—	—	—	—	—
Legacy [(1)]	85.0	22.5	—	—	—	—	—	—
Southern Region								
Haynesville/Cotton Valley	91.0	36.7	—	—	6.0	1.7	2.0	0.7
Midcontinent	221.0	39.6	—	—	—	—	4.0	1.9
Total	678.0	176.7	—	—	6.0	1.7	6.0	2.6
Year Ended December 31, 2010								
Northern Region								
Pinedale	103.0	72.5	—	—	—	—	—	—
Uinta Basin	188.0	23.9	—	—	—	—	—	—
Legacy [(1)]	42.0	7.7	—	—	—	—	1.0	0.9
Southern Region								
Haynesville/Cotton Valley	85.0	44.0	—	—	33.0	16.2	1.0	1.0
Midcontinent	98.0	22.4	—	—	—	—	—	—
Total	516.0	170.5	—	—	33.0	16.2	2.0	1.9

(1) Due to the 2012 Acquisition, the Company began breaking out the results of Williston Basin from Legacy in 2012. The Legacy well totals for the years ended December 31, 2011 and 2010, include the total development and exploratory wells drilled in the Williston Basin.

The following table presents operated and non-operated well completions for the year ended December 31, 2012:

	Operated Completions		Non-operated Completions	
	Gross	Net	Gross	Net
Northern Region				
Pinedale	102	73.3	—	—
Williston Basin	28	24.2	60	3.9
Uinta Basin	48	45.2	207	0.5
Legacy	7	4.6	24	2.0
Southern Region				
Haynesville/Cotton Valley	29	16.5	8	0.8
Midcontinent	26	20.4	131	11.8

The following table presents operated and non-operated wells drilling and waiting on completion at December 31, 2012:

	Operated				Non-operated			
	Drilling		Waiting on completion		Drilling		Waiting on completion	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Northern Region								
Pinedale [(1)]	2	2.0	63	45.9	—	—	—	—
Williston Basin	11	9.4	9	8.0	16	1.1	23	0.8
Uinta Basin	8	8.0	3	3.0	—	—	—	—
Legacy	—	—	—	—	6	0.2	—	—
Southern Region								
Haynesville/Cotton Valley	—	—	5	2.4	—	—	—	—
Midcontinent	3	2.1	10	8.8	6	0.5	35	1.6

(1) QEP suspends Pinedale completion operations during the coldest months of the winter, generally from December to mid-March.

Delivery Commitments

The Company sells NGL under a term sales agreement that contains a delivery commitment for 8,500 barrels per day of NGL extracted at several of QEP Field Services' gas processing facilities in the Northern Region. The agreement, which was effective May 1, 2010, extends for a period of seven years and contains terms and conditions customary for an agreement of this type in the oil and gas industry. The Company believes that the reserves dedicated to its gas processing facilities and projected processing volumes are adequate to satisfy its delivery commitments under this agreement.

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

Period		Delivery Commitments
		(millions of MMBtu)
	2013	**164.7**
	2014	**54.8**
	2015	**29.8**

These commitments are physical delivery obligations with prices related to the prevailing index prices for natural gas at the time of delivery. None of these commitments require the Company to deliver natural gas produced specifically from any of the Company's properties. The Company believes that its production and reserves are adequate to meet these term sales commitments. If for some reason the Company's natural gas production is not sufficient to satisfy its term sales commitments, the Company believes it can purchase sufficient volumes of natural gas in the market at index-related prices to satisfy its commitments. See also Item 7 "Contractual Cash Obligations and Other Commitments" for discussion of firm transportation and storage commitments related to natural gas deliveries.

In addition, none of the Company's production from QEP Energy's owned properties is subject to any priorities, proration or third-party imposed curtailments that may affect quantities delivered to its customers, any 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 Item 1A - Risk Factors, in this Annual Report on Form 10-K.

Midstream Field Services – QEP Field Services

QEP Field Services owns 1,950 miles of gathering lines in Utah, Wyoming, Colorado, Louisiana and North Dakota. At December 31, 2012, QEP Field Services owns six processing plants, which extract NGL from the natural gas stream and have an aggregate capacity of 1.37 Bcf per day of unprocessed natural gas. In addition, QEP Field Services owns treating facilities in northwest Louisiana which remove impurities from the natural gas stream and have an aggregate capacity of 600 MMcf per day of untreated natural gas. QEP Field Services also owns compression facilities and field dehydration and measurement systems. The 21-mile, 20-inch diameter pipeline owned by Rendezvous Pipeline can deliver up to 300 MMcf of natural gas per day to the Kern River Pipeline. QEP Field Services' partnership facilities include the RGS system, consisting of 300 miles of gathering lines and associated field equipment, the UBFS system, which consists of 78 miles of gathering lines and associated field equipment, and the Three Rivers system, which consists of 52 miles of gathering lines and associated field equipment. QEP Field Services Company owns a 60 mile crude oil pipeline regulated by FERC under the ICA.

In February 2013, QEP Field Services put into service the 150 MMcf per day cryogenic Iron Horse II processing plant, an expansion of its Stagecoach and Iron Horse processing complex in the Uinta Basin of eastern Utah. The plant predominantly provides fee-based processing services to third parties and affiliates.

Energy Marketing – QEP Marketing

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

ITEM 3. LEGAL PROCEEDINGS

QEP is a defendant in a number of lawsuits and is involved in governmental proceedings and regulatory controls arising in the ordinary course of business. QEP is also subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. While the ultimate outcome and impact on QEP cannot be predicted with certainty, except as discussed below, management does not believe that the resolution of pending proceedings will materially affect the Company's consolidated financial position, results of operations, or cash flows.

Chieftain Royalty Company v. QEP Energy Company, Case No CJ2011-1, U. S. District Court for the Western District of Oklahoma. This statewide class action was filed on January 20, 2011, on behalf of QEP's Oklahoma royalty owners asserting various claims for damages related to royalty valuation on all of QEP's Oklahoma wells operated by QEP or from which QEP marketed gas. Claims included breach of contract, breach of fiduciary duty, fraud, unjust enrichment, tortious breach of contract, conspiracy, and conversion, based generally on asserted improper deduction of post-production costs. The Court certified the class as to the breach of contract, breach of fiduciary duty and unjust enrichment claims. The parties successfully mediated the case in January 2013. On February 13, 2013, the parties executed a Stipulation and Agreement of Settlement (the Chieftain Settlement Agreement) providing for a cash payment from QEP to the class in the amount of $115.0 million, payable into an escrow account within five business days following the Court's preliminary approval of the settlement. In consideration for the settlement payment, QEP will receive a full release of all claims regarding the calculation, reporting and payment of royalties from the sale of natural gas and its constituents for all periods prior to February 28, 2013, and all class members are enjoined from asserting claims related to such royalties. As part of the Chieftain Settlement Agreement, the parties also agreed on the methodology for the calculation and payment of future royalties payable by QEP, or its successors and assigns, under all class leases for the life of such leases. The Court has entered a Preliminary Order Approving Class Action Settlement.

Questar Gas Company v. QEP Field Services Company, Civil No. 120902969, Third Judicial District Court, State of Utah. QEP Field Services' former affiliate Questar Gas Company (QGC) filed this complaint in state court in Utah on May 1, 2012, asserting claims for breach of contract and breach of implied covenant of good faith and fair dealing, for an accounting and declaratory judgment related to a 1993 gathering agreement (1993 Agreement) entered into when the parties were affiliates.

Under the 1993 Agreement, QEP Field Services provides gathering services for producing properties developed by former affiliate Wexpro Company on behalf of QGC's utility ratepayers. The core dispute pertains to the annual calculation of the gathering rate, which is based on a cost of service concept expressed in the 1993 Agreement and in a 1998 amendment. The annual gathering rate has been calculated in the same manner under the contract since it was amended in 1998, without any prior objection or challenge by QGC. Specific monetary damages are not asserted. Also, on May 1, 2012, QEP Field Services Company filed a legal action against QGC entitled *QEP Field Services Company v. Questar Gas Company*, in the Second District Court in Denver County, Colorado, seeking declaratory judgment relating to its gathering service and charges under the same agreement.

In October 2009, the Company received a cease and desist order from the U.S. Army Corps of Engineers (COE) to refrain from unpermitted work resulting in the discharge of dredged and/or fill material into waters of the United States at three sites located in Caddo and Red River Parishes, Louisiana. EPA Region 6 has assumed lead responsibility for enforcement of the cease and desist order and any possible future orders for the removal of unauthorized fills and/or civil penalties under the Clean Water Act. In 2012, the Company completed a field audit, which identified 112 additional instances affecting approximately 90 acres where work may have been conducted in violation of the Clean Water Act. The Company has disclosed each of these instances to the EPA under the EPA's Audit Policy (to reduce penalties) and to the COE. The Company is working with the EPA and the COE to resolve these matters, which will require the Company to undertake certain mitigation and permitting activities, and may require the Company to pay a monetary penalty. At this time, QEP is unable to estimate the potential loss related to this matter, but believes it exceeds the $100,000 threshold for disclosure of environmental matters.

See also Note 9 (Commitments and Contingencies) to the consolidated financial statements in Item 8 of Part II of this Annual Report.

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, 2013, QEP had 7,260 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. The Company expects that cash dividends will continue to be paid in the future.

The following table is a summary of the high and low sales price per share of QEP's common stock on the NYSE and quarterly dividends paid per share:

	High price	Low price	Dividend
		(per share)	
2012			
First quarter	**$ 35.61**	**$ 26.73**	**$ 0.02**
Second quarter	**32.03**	**24.35**	**0.02**
Third quarter	**33.50**	**26.12**	**0.02**
Fourth quarter	**32.92**	**25.99**	**0.02**
Total			**$ 0.08**
2011			
First quarter	$ 42.00	$ 35.78	$ 0.02
Second quarter	43.70	37.11	0.02
Third quarter	45.20	26.52	0.02
Fourth quarter	38.44	23.56	0.02
Total			$ 0.08

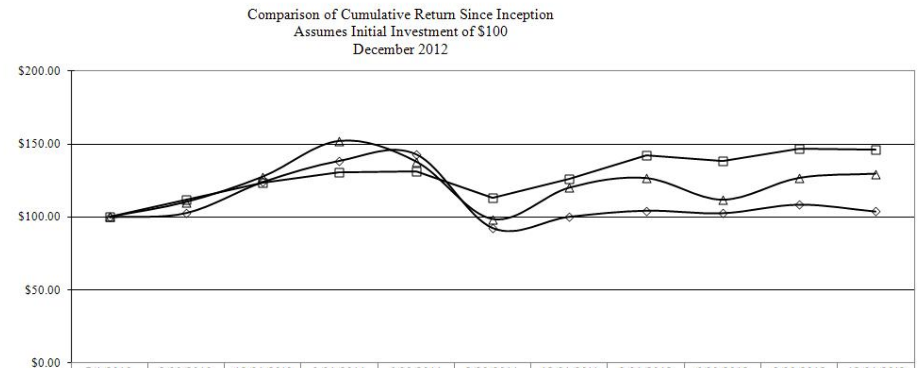
Stock Performance Graph

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 incorporate it by reference into such a filing.

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 peer group as of July 1, 2010, which is the date when QEP's common stock began trading on the NYSE;
- Investment in the Company's peer group 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.

QEP's peer group, as defined, consists of the following companies: Cabot Oil & Gas Corporation, Cimarex Energy Company, Denbury Resources Inc., EOG Resources, Inc., Forest Oil Corporation, Newfield Exploration Company, Noble Energy, Inc., Pioneer Natural Resources Company, Plains Exploration & Production Company, Quicksilver Resources, Inc., Range Resources Corporation, Southwestern Energy Company, Ultra Petroleum Corporation and Whiting Petroleum Corporation. Management believes this peer group provides a meaningful comparison based upon the Company's review of asset size, geographic location of assets, market capitalization, revenues, culture and performance, among other things.



	7/1/2010	9/30/2010	12/31/2010	3/31/2011	6/30/2011	9/30/2011	12/31/2011	3/31/2012	6/30/2012	9/30/2012	12/31/2012
QEP Resources, Inc.	100.00	102.90	124.03	138.56	143.03	92.61	100.30	104.47	102.73	108.60	103.91
S&P 500 Index - Total Returns	100.00	111.65	123.66	130.98	131.11	112.93	126.27	142.16	138.25	147.03	146.48
Peer Group	100.00	110.30	127.71	152.27	138.07	98.46	120.07	126.72	111.78	126.78	129.66

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

QEP had no unregistered sales of securities, or purchases of equity securities by QEP or affiliated purchasers, during the fourth quarter of 2012.

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data for the five years ended December 31, 2012, is provided in the table below. Refer to Item 7 and Item 8 in Part II of this Annual Report on Form 10-k for discussion of facts affecting the comparability of the Company's financial data.

	Year Ended December 31,				
	2012	2011	2010	2009	2008
	(in millions, except per share information)				
***Results of Operations* [1]**					
Revenues [2]	**$ 2,349.8**	$ 3,159.2	$ 2,300.6	$ 2,011.2	$ 2,360.9
Operating (loss) income	**(133.3)**	505.9	545.3	585.5	933.2
Income from continuing operations	**132.0**	270.4	285.9	215.4	520.6
Discontinued operations, net of income tax	**—**	—	43.2	80.7	73.9
Net income attributable to QEP	**128.3**	267.2	326.2	293.5	585.5
Earnings per common share attributable to QEP					
Basic from continuing operations	**$ 0.72**	$ 1.51	$ 1.61	$ 1.23	$ 2.96
Basic from discontinued operations	**—**	—	0.25	0.46	0.43
Basic total	**$ 0.72**	$ 1.51	$ 1.86	$ 1.69	$ 3.39
Diluted from continuing operations	**$ 0.72**	$ 1.50	$ 1.60	$ 1.21	$ 2.90
Diluted from discontinued operations	**—**	—	0.24	0.46	0.42
Diluted total	**$ 0.72**	$ 1.50	$ 1.84	$ 1.67	$ 3.32
Dividends per share	**$ 0.08**	$ 0.08	$ 0.04	**$** —	$ —
Weighted-average common shares outstanding					
Used in basic calculation	**177.8**	176.5	175.3	174.1	172.8
Used in diluted calculation	**178.7**	178.4	177.3	176.3	176.1
Financial Position					
Total Assets at December 31,	**$ 9,108.5**	$ 7,442.7	$ 6,785.3	$ 6,481.4	$ 6,342.7
Capitalization at December 31,					
Long-term debt	**3,206.9**	1,679.4	1,530.8	1,348.7	1,299.1
Total equity	**3,313.7**	3,352.1	3,063.1	2,808.7	2,779.4
Total Capitalization	**$ 6,520.6**	$ 5,031.5	$ 4,593.9	$ 4,157.4	$ 4,078.5
Cash Flow From Continuing Operations					
Net cash provided by operating activities	**1,296.0**	$ 1,292.6	$ 997.5	$ 1,149.4	$ 1,224.7
Capital expenditures	**(2,799.7)**	(1,431.1)	(1,469.0)	(1,196.9)	(2,136.7)
Net cash used in investing activities	**(2,794.5)**	(1,422.9)	(1,390.5)	(1,146.4)	(2,021.0)
Net cash provided by (used in) financing activities	**1,498.5**	130.3	373.7	(8.8)	818.7
Non-GAAP Measures					
Adjusted EBITDA [3]	**1,415.5**	$ 1,386.6	$ 1,140.5	$ 1,165.5	$ 1,310.7

(1) QEP completed a Spin-off from Questar in June 2010 as discussed in more detail in Item 1 of Part I of this Annual Report on Form 10-K. As a result of the Spin-off, Wexpro's financial results have been reflected as discontinued operations and all prior periods have been recast.

(2) Revenue for the years ended December 31, 2011 and 2010, reflect the impact of QEP's settled derivative contracts which during the year ended December 31, 2012, are reflected below operating (loss) income. See Note 6 - Derivative Contracts, in Part II, Item 8 of this Annual Report on Form 10-K for detailed information on derivative contract settlements in the years ended December 31, 2012, 2011 and 2010.

(3) Adjusted EBITDA is a non-GAAP financial measure. Management defines Adjusted EBITDA as net income before the following items: separation costs, accrued litigation loss contingency, depreciation, depletion and amortization, exploration expense, abandonment and impairment, gains and losses from asset sales, unrealized gains and losses on derivative contracts, interest and other income, loss on early extinguishment of debt, interest expense, income taxes and discontinued operations. Management focuses on Adjusted EBITDA to assess the Company's operating results. Management believes Adjusted EBITDA is an important measure of the Company's cash flow and liquidity and its ability to incur and service debt, fund capital expenditures and make distributions to shareholders, and an important measure for comparing the Company's financial performance to other gas and oil producing companies.

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

	Year Ended December 31,				
	2012	2011	2010	2009	2008
	(in millions, except per share information)				
Adjusted EBITDA					
Net income attributable to QEP	**$ 128.3**	$ 267.2	$ 326.2	$ 293.5	$ 585.5
Net income attributable to noncontrolling interest	**3.7**	3.2	2.9	2.6	$ 9.0
Net income	**132.0**	270.4	329.1	296.1	594.5
Discontinued operations, net of tax	**—**	—	(43.2)	(80.7)	(73.9)
Income from continuing operations	**132.0**	270.4	285.9	215.4	520.6
Unrealized (gains) losses on derivative contracts	**(63.2)**	(117.7)	(121.7)	164.0	79.2
Net gains from asset sales	**(1.2)**	(1.4)	(12.1)	(1.5)	(60.4)
Interest and other income	**(6.6)**	(4.1)	(2.3)	(4.5)	(10.2)
Income taxes	**66.5**	154.4	167.0	117.6	283.6
Interest expense	**122.9**	90.0	84.4	70.1	61.7
Accrued litigation loss contingency [1]	**115.0**	—	—	—	—
Separation costs	**—**	—	13.5	—	—
Loss from early extinguishment of debt	**0.6**	0.7	13.3	—	—
Depreciation, depletion and amortization	**904.9**	765.4	643.4	559.1	361.5
Abandonment and impairment	**133.4**	218.4	46.1	20.3	45.4
Exploration expenses	**11.2**	10.5	23.0	25.0	29.3
Adjusted EBITDA	**$ 1,415.5**	$ 1,386.6	$ 1,140.5	$ 1,165.5	$ 1,310.7

(1) See Note 9 (Commitments and Contingencies) to the consolidated financial statements in Item 8 of Part II of this Annual Report.

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.

The following information updates the discussion of QEP's financial condition provided in its 2011 Annual Report on Form 10-K filing, and analyzes the changes in the results of operations between the years ended December 31, 2012 and 2011, and between the years ended December 31, 2011 and 2010.

OVERVIEW

QEP Resources, Inc. (QEP or the Company) is a holding company with three major lines of business: natural gas and crude oil exploration and production (QEP Energy); midstream field services (QEP Field Services); and energy marketing (QEP Marketing).

Outlook

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, Pinedale Anticline, Uinta Basin, Woodford "Cana" and Haynesville Shale. These resource plays are characterized by unconventional oil or natural 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 has a large inventory of lower-risk, predictable development drilling locations across its acreage holdings in the onshore United States that provide a solid base for consistent growth in organic production and reserves. QEP believes that it has one of the lowest cash operating structures among its exploration and production company peers. However, in certain of its resource plays, QEP, along with its peers, has experienced increased drilling and completion costs which could impact future drilling plans.

While predominantly a natural gas producer, the Company has increased its focus on growing the relative proportion of crude oil and NGL production in its exploration and production business. As part of the Company's liquids growth strategy, QEP Energy completed the 2012 Acquisition during the third quarter of 2012 and acquired oil and gas properties in the Williston Basin.

During the year ended December 31, 2012, QEP Energy increased its crude oil and NGL production by 80% compared with 2011. During 2012, crude oil and NGL revenue accounted for approximately 52% of QEP Energy's field-level production revenues.

While QEP believes that it can grow production and reserves from its extensive inventory of identified drilling locations, the Company continues to evaluate acquisition opportunities that might create significant long-term value. QEP believes that its experience, expertise, and substantial presence in its core operating areas, combined with its low-cost operating model and financial strength, enhance its ability to pursue acquisition opportunities. In addition, the Company is seeking to divest select non-core portfolio assets to redirect capital towards higher-return projects.

QEP owns and operates gathering and transmission pipelines and natural gas processing and treatment facilities in many of its core producing areas. These assets enable the Company to promptly connect its wells, better control its costs, and generate a significant, consistent revenue stream by providing gathering and processing services to third parties. In early January 2013, QEP announced that its Board of Directors had authorized the formation of a Master Limited Partnership (MLP) to support the growth of QEP's midstream business. QEP expects to file a registration statement with the SEC in the second quarter of 2013 for an initial public offering of common units of the MLP. QEP plans to contribute a majority of its gathering assets in Wyoming and North Dakota to the MLP. QEP expects to sell a minority interest in the MLP and raise $300 million to $400 million in gross proceeds. QEP plans to use the proceeds from such offering to fund ongoing operations, to repay debt under the Company's revolving credit facility and for general corporate purposes. QEP's announcement of this plan did not, and this disclosure does not, constitute an offer to sell or the solicitation of an offer to buy any securities and shall not constitute an offer, solicitation or sale in any jurisdiction in which such offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of that jurisdiction.

Financial and Operating Results

During the year ended December 31, 2012, QEP Energy experienced substantial production growth, while QEP Field Services increased system throughput. For the years ended December 31, 2012 and 2011, QEP Energy reported total equivalent production of 319.2 Bcfe and 275.2 Bcfe, increases of 16% and 20%, from the 2011 and 2010 comparable prior periods, respectively. QEP Field Services' gathering throughput volumes during the years ended December 31, 2012 and 2011, were 2% and 4% higher, respectively, than the 2011 and 2010 comparable periods. During the years ended December 31, 2012 and 2011, QEP Field Services reported 3% and 42% increases in NGL sales volumes, respectively. QEP Field Services' fee-based processing volumes were 4% and 6% higher during the years ended December 31, 2012 and 2011, respectively, when compared to the prior year periods.

The increases in production at QEP Energy and system throughput at QEP Field Services were offset by declining commodity prices at both QEP Energy and QEP Field Services. For the years ended December 31, 2012, 2011 and 2010, QEP Energy's average net realized equivalent prices (including realized commodity derivative impact) were $5.48 per Mcfe, $5.72 per Mcfe and $5.81 per Mcfe, respectively. In addition, at QEP Field Services, the increase in NGL sales volumes during 2012, was offset by a decrease in average net realized NGL sales prices. Specifically, during 2012, a 21% decrease in the average net realized NGL sales price occurred, resulting in a 35% decrease to the keep-whole processing margin. During 2011, QEP Field Services' average net realized sales prices were 34% higher than 2010.

At the end of the third quarter of 2012, QEP Energy acquired oil and gas properties in the Williston Basin for approximately $1.4 billion. The properties are located in Williams and McKenzie counties of North Dakota, approximately 12 miles west of QEP's existing core acreage in the Williston Basin. The 2012 Acquisition added revenues of $63.7 million and net income of $14.9 million to QEP's fourth quarter results.

In the first quarter of 2012, QEP completed a public offering for $500.0 million in aggregate principal amount of 5.375% senior notes due in October 2022 (2022 Senior Notes). The 2022 Senior Notes were issued at par. The net proceeds of $493.1 million were used to repay indebtedness under QEP's revolving credit facility.

During the second quarter of 2012, QEP entered into a $300.0 million senior unsecured term loan agreement (Term Loan) with a group of financial institutions. The Term Loan provides for borrowings at short-term interest rates and contains covenants, restrictions and interest rates that are substantially the same as the Company's existing revolving credit agreement. The Term Loan matures in April 2017, and the maturity date may be extended one year with the agreement of the lenders. In conjunction with the Term Loan, QEP entered into interest rate swap contracts with an aggregate notional amount of $300.0 million that effectively lock in a fixed rate of 1.07% that QEP will pay over the duration of the Term Loan.

QEP completed a public offering for $650.0 million in aggregate principal amount of 5.25% senior notes due in May 2023 (2023 Senior Notes) in the third quarter of 2012. The 2023 Senior Notes were issued at par. The estimated net proceeds of approximately $641 million were used to fund a portion of the 2012 Acquisition.

Factors Affecting Results of Operations

Oil, Natural Gas, and NGL Prices
Historically, field-level prices received for QEP's natural gas, NGL, and crude oil production have been volatile and unpredictable, and that volatility is expected to continue. In recent years, domestic natural gas supply has grown faster than natural gas demand, 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 natural gas from shale, tight sand formations, and other unconventional reservoirs. Increased natural gas supplies have resulted in downward pressure on natural gas prices, while concern about the global economy and other factors has created volatility in the price of crude oil. Changes in the market prices for natural gas, crude 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, and costs of goods and services required to drill and complete wells, and may impact the carrying value of its oil and natural gas properties.

QEP uses commodity derivatives to reduce the volatility of the prices QEP receives for a portion of its production and to 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% of its forecasted annual production by the end of the first quarter of each fiscal year. Assuming 2013 annual production of 327.5 Bcfe, QEP Energy had approximately 44% of its forecasted natural gas, oil and NGL equivalent production covered with fixed-price swaps or costless collars, including 51% of its forecasted natural gas production covered with fixed-price swaps. See Item 7A of Part II of this Annual Report on Form 10-K for further details concerning QEP's commodity derivatives transactions. In addition, as a result of the continued relative price relationship between crude oil, NGL and natural gas prices, QEP Energy has allocated approximately 98% of its 2013 total forecasted capital expenditure budget to crude oil and liquids-rich natural gas plays.

Unrealized Derivative Gains and Losses
The Company elected to discontinue hedge accounting beginning January 1, 2012, and unrealized gains and losses from mark-to-market valuations of all derivative positions are reflected as unrealized derivative gains or losses in the Company's Consolidated Statement of Operations. See Note 6 - Derivative Contracts, to the Consolidated Financial Statements, in Item 8, Part II of this Annual Report on Form 10-K, for additional information regarding the discontinuance of hedge accounting. The payments due to or from counterparties on these derivatives will typically be offset by corresponding changes in prices ultimately received from the sale of QEP's production. QEP has incurred significant unrealized gains and losses in 2012, and in prior periods and may continue to incur these types of gains and losses in the future.

Global Geopolitical and Macroeconomic Factors
QEP continues to monitor the outlook of the global economy, including the European debt crisis and its potential impact on global economic growth and the banking and financial sectors, political unrest in the Middle East, a slowing of growth in Asia, particularly China, the United States federal budget deficit, changes in regulatory oversight policy and commodity price volatility. 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 natural gas, NGL and crude oil supply, demand and prices, and could materially impact the Company's financial position, results of operations and cash flow from operations and operating activities.

Supply, Demand and Other Market Risk Factors
U.S. natural gas directed drilling rig count decreased throughout 2012, as producers reduced drilling for natural gas in response to low natural gas prices. A reduction in natural gas production has lagged the downturn in the natural gas rig count because natural gas producers have a significant inventory of drilled wells waiting on completion and new high-rate horizontal wells continue to be completed. As a result of the lag, U.S. natural gas production did not decline in 2012. The U.S. natural gas market entered the storage injection season with record high inventory levels. However, strong natural gas demand from electric power generation has resulted in a general firming of natural gas prices during the last half of 2012. Despite increased stability in natural gas prices during the second half of 2012, QEP expects U.S. natural gas prices to remain volatile and below the five year average price over the near term. Continued low natural gas prices have caused U.S. E&P companies, including QEP, to shift capital investments away from predominantly dry gas areas toward plays that are known to have liquids-rich natural gas and crude oil. This shift in focus has caused domestic NGL production to increase dramatically. Increased NGL products, warmer-than-average winters, and price dislocations from infrastructure bottlenecks in certain regions, have all contributed to a weakening in domestic NGL prices, particularly ethane. QEP expects NGL prices to remain volatile for the foreseeable future. QEP anticipates global crude oil prices to remain near current levels, assuming the global economy and socio-political backdrops remain relatively stable. Disruption to the global oil supply system, political and/or economic instability, and/or other factors could trigger additional volatility in crude oil prices. In addition, transportation, refining, or other infrastructure constraints could introduce significant price differentials between regional markets where QEP sells its crude oil production and national (NYMEX or Cushing) and global (Brent or U.S. Gulf Coast) markets. Because of the global and regional price volatility and the uncertainty around the commodity price environment, QEP continues to manage its capital spending program and financial flexibility accordingly.

Potential for Future Asset Impairments
In 2012, U.S. natural gas prices were lower than in 2011 and 2010. The carrying value of the Company's properties is sensitive to declines in natural gas, crude oil and NGL prices. These assets are at risk of impairment if future prices for natural gas, crude oil or NGL prices decline. The cash flow model that the Company uses to assess proved properties for impairment includes numerous assumptions, such as management's estimates of future oil, gas and NGL production, market outlook on forward commodity prices, operating and development costs, and discount rates. All inputs to the cash flow model must be evaluated at each date of estimate. However, a decrease in forward natural gas, crude oil and NGL prices alone could result in an impairment of properties. For additional information see Item 1A - Risk Factors, of Part I and see Item 8 of Part II, Note 1 - Significant Accounting Policies, of this Annual Report on Form 10-K. During the year ended December 31, 2012, QEP recorded abandonment and impairment charges of $133.4 million, on some of its oil and gas properties. The impairment charges related to the reduced value of certain fields resulting from lower natural gas, crude oil and NGL prices and impairments of unproven leasehold costs. Proved impairments were primarily the result of lower natural gas and NGL prices that impacted the carrying value of proved reserves in several Midcontinent (Oklahoma and Texas) and one Uinta Basin successful efforts pools. Of the $133.4 million abandonment and impairment charge during 2012, $107.6 million related to the impairment charge on proved properties and $23.7 million related to impairment on unproved properties. Oil and gas properties and leaseholds in the Southern Region accounted for $104.8 million of the $133.4 million abandonment and impairment charges during 2012, and $28.6 million related to oil and gas properties and leaseholds in the Northern Region.

RESULTS OF OPERATIONS

Net Income

QEP Resources' net income attributable to QEP during the year ended December 31, 2012, was $128.3 million, or $0.72 per diluted share, compared to $267.2 million, or $1.50 per diluted share, in 2011. The decrease in net income during 2012, was due to an 101% decrease in QEP Energy's net income, a 17% decrease in QEP Field Services' net income and an 100% decrease in QEP Marketing and other net income. QEP Energy's net income decreased during 2012, due to the accrual of a $115.0 million litigation loss contingency, 4% lower net realized equivalent commodity prices, and a 18% increase in DD&A, partially offset by a $68.4 million unrealized gain on commodity derivative contracts, $87.9 million lower proved property impairment charges and production volumes that increased 16%. QEP Field Services' decrease in net income during 2012, was driven by a 35% decrease in the keep-whole processing margin and 7% lower gathering margins. QEP Resources' net income from continuing operations attributable to QEP in 2011 was $267.2 million, or $1.50 per diluted share, compared to $283.0 million, or $1.60 per diluted share, in 2010. The decrease in 2011 was due to a $99.2 million, or 49%, decline in QEP Energy's net income, partially offset by a $63.4 million, or 70%, increase in QEP Field Services' net income. QEP Energy's net income declined in 2011 because of a price-related impairment charge of $195.5 million during 2011 on some of its mature, dry gas, and higher cost properties in both the Northern and Southern Regions. Offsetting the decline at QEP Energy, QEP Field Services' increase in net income was driven by higher gathering and processing margins and increased throughput volumes.

The following table provides a summary of net income from continuing operations attributable to QEP by line of business:

	Year Ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
			(in millions)		
QEP Energy	**$ (0.7)**	$ 104.7	$ 203.9	**$ (105.4)**	$ (99.2)
QEP Field Services	**129.0**	154.5	91.1	**(25.5)**	63.4
QEP Marketing and other	**—**	8.0	(12.0)	**(8.0)**	20.0
Net income from continuing operations	**$ 128.3**	$ 267.2	$ 283.0	**$ (138.9)**	$ (15.8)
Earnings per diluted share	**$ 0.72**	$ 1.50	$ 1.60	**$ (0.78)**	$ (0.10)
Average diluted shares	**178.7**	178.4	177.3	**0.3**	1.1

Adjusted EBITDA

Management believes Adjusted EBITDA (a non-GAAP financial measure) is an important measure of the Company's cash flow, liquidity, and ability to incur and service debt, fund capital expenditures and make distributions to shareholders. The use of this measure allows investors to understand how management evaluates financial performance to make operating decisions and allocate resources. It is also an important measure for comparing the Company's financial performance to other gas and oil producing companies.

Management defines Adjusted EBITDA as net income before the following items: separation costs, accrued litigation loss contingency, depreciation, depletion and amortization, exploration expense, abandonment and impairment, gains and losses from asset sales, unrealized gains and losses on derivative contracts, interest and other income, loss on early extinguishment of debt, interest expense, income taxes and discontinued operations.

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

	Year Ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
			(in millions)		
QEP Energy	**$ 1,133.6**	$ 1,057.5	$ 926.2	**$ 76.1**	$ 131.3
QEP Field Services	**281.1**	320.3	203.9	**(39.2)**	116.4
QEP Marketing and other	**0.8**	8.8	10.4	**(8.0)**	(1.6)
Adjusted EBITDA	**$ 1,415.5**	$ 1,386.6	$ 1,140.5	**$ 28.9**	$ 246.1

Adjusted EBITDA increased to $1,415.5 million during the year ended December 31, 2012, compared to $1,386.6 million in 2011. During 2012, QEP Energy's Adjusted EBITDA increased 7%, despite 15% lower net realized natural gas prices and 24% lower net realized NGL prices. The impact of lower net realized prices during 2012 was offset by a 16% increase in total production at QEP Energy. QEP Field Services' Adjusted EBITDA decreased 12% due to a decrease in the keep-whole processing margin and lower gathering margins. Adjusted EBITDA increased 22% to $1,386.6 million for 2011, compared to $1,140.5 million in the 2010 period, despite an 11% decrease in net realized natural gas prices. The impact of lower net realized natural gas prices during 2011, was offset by a 20% increase in total production, 30% higher net realized crude oil prices and 22% higher net realized NGL prices in QEP Energy, along with increased gathering margins that were 22% higher and processing margins that were 93% higher in QEP Field Services.

The following table is a reconciliation of Adjusted EBITDA to QEP Resources' net income, the most comparable GAAP financial measure:

	Year Ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
	(in millions)				
Net income attributable to QEP Resources	**$ 128.3**	$ 267.2	$ 326.2	**$ (138.9)**	$ (59.0)
Net income attributable to noncontrolling interest	**3.7**	3.2	2.9	**0.5**	0.3
Net income	**132.0**	270.4	329.1	**(138.4)**	(58.7)
Discontinued operations, net of tax	**—**	—	(43.2)	**—**	43.2
Income from continuing operations	**132.0**	270.4	285.9	**(138.4)**	(15.5)
Unrealized gains on derivative contracts	**(63.2)**	(117.7)	(121.7)	**54.5**	4.0
Net gain from asset sales	**(1.2)**	(1.4)	(12.1)	**0.2**	10.7
Interest and other income	**(6.6)**	(4.1)	(2.3)	**(2.5)**	(1.8)
Income tax provision	**66.5**	154.4	167.0	**(87.9)**	(12.6)
Interest expense	**122.9**	90.0	84.4	**32.9**	5.6
Accrued litigation loss contingency	**115.0**	—	—	**115.0**	—
Separation costs	**—**	—	13.5	**—**	(13.5)
Loss on early extinguishment of debt	**0.6**	0.7	13.3	**(0.1)**	(12.6)
Depreciation, depletion and amortization	**904.9**	765.4	643.4	**139.5**	122.0
Abandonment and impairment	**133.4**	218.4	46.1	**(85.0)**	172.3
Exploration expenses	**11.2**	10.5	23.0	**0.7**	(12.5)
Adjusted EBITDA	**$ 1,415.5**	$ 1,386.6	$ 1,140.5	**$ 28.9**	$ 246.1

The following table is a reconciliation of QEP Energy Adjusted EBITDA to net income:

	Year Ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
	(in millions)				
Net income from continuing operations attributable to QEP Energy	**$ (0.7)**	$ 104.7	$ 203.9	**$ (105.4)**	$ (99.2)
Unrealized gains on derivative contracts	**(68.4)**	(117.7)	(121.7)	**49.3**	4.0
Net gain from asset sales	**(1.2)**	(1.4)	(13.7)	**0.2**	12.3
Interest and other income	**(6.2)**	(4.0)	(2.1)	**(2.2)**	(1.9)
Income tax (benefit) provision	**(4.3)**	57.9	119.7	**(62.2)**	(61.8)
Interest expense	**116.8**	81.9	78.5	**34.9**	3.4
Accrued litigation loss contingency	**115.0**	—	—	**115.0**	—
Depreciation, depletion and amortization	**838.0**	707.2	592.5	**130.8**	114.7
Abandonment and impairment	**133.4**	218.4	46.1	**(85.0)**	172.3
Exploration expenses	**11.2**	10.5	23.0	**0.7**	(12.5)
Adjusted EBITDA	**$ 1,133.6**	$ 1,057.5	$ 926.2	**$ 76.1**	$ 131.3

The following table is a reconciliation of QEP Field Services' Adjusted EBITDA to net income:

	Year Ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
	(in millions)				
Net income from continuing operations attributable to QEP Field Services	**$ 129.0**	$ 154.5	$ 91.1	**$ (25.5)**	$ 63.4
Net income attributable to noncontrolling interest	**3.7**	3.2	2.9	**0.5**	0.3
Net income	**132.7**	157.7	94.0	**(25.0)**	63.7
Net gain from asset sales	**—**	—	1.6	**—**	(1.6)
Interest and other income	**(0.2)**	(0.1)	(0.1)	**(0.1)**	—
Income tax provision	**71.8**	93.4	51.9	**(21.6)**	41.5
Interest expense	**13.6**	13.6	7.6	**—**	6.0
Depreciation, depletion and amortization	**63.2**	55.7	48.9	**7.5**	6.8
Adjusted EBITDA	**$ 281.1**	$ 320.3	$ 203.9	**$ (39.2)**	$ 116.4

The following table is a reconciliation of QEP Marketing and other Adjusted EBITDA to net income:

	Year Ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
	(in millions)				
Net income from continuing operations attributable to QEP Marketing and other	**$ —**	$ 8.0	$ 31.2	**$ (8.0)**	$ (23.2)
Discontinued operations, net of tax	**—**	—	(43.2)	**—**	43.2
Income from continuing operations	**—**	8.0	(12.0)	**(8.0)**	20.0
Unrealized loss on derivative contracts	**5.2**	—	—	**5.2**	—
Other income	**(0.2)**	—	(0.1)	**(0.2)**	0.1
Income tax (benefit) provision	**(1.0)**	3.1	(4.6)	**(4.1)**	7.7
Interest income, net of interest expense	**(7.5)**	(5.5)	(1.7)	**(2.0)**	(3.8)
Separation costs	**—**	—	13.5	**—**	(13.5)
Loss on early extinguishment of debt	**0.6**	0.7	13.3	**(0.1)**	(12.6)
Depreciation, depletion and amortization	**3.7**	2.5	2.0	**1.2**	0.5
Adjusted EBITDA	**$ 0.8**	$ 8.8	$ 10.4	**$ (8.0)**	$ (1.6)

Production

QEP Energy reported production of 319.2 Bcfe during the year ended December 31, 2012, a 16% increase over the 275.2 Bcfe a year earlier. During the year ended December 31, 2011, QEP Energy reported a 20% increase in production from 2010. On an energy-equivalent basis, crude oil and NGL comprised approximately 22% of QEP Energy's production for 2012, up from 14% and 11% during 2011 and 2010, respectively.

A summary of QEP Energy production is shown in the following table:

	Year Ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
QEP Energy Production Volumes					
Natural gas (Bcf)	**249.3**	236.4	203.8	**12.9**	32.6
Oil (Mbbl)	**6,306.9**	3,741.3	2,979.8	**2,565.6**	761.5
NGL (Mbbl)	**5,349.0**	2,715.6	1,225.8	**2,633.4**	1,489.8
Total production (Bcfe)	**319.2**	275.2	229.0	**44.0**	46.2
Average daily production (MMcfe)	**872.1**	753.9	627.4	**118.2**	126.5

Pricing

A regional comparison of average field-level prices is shown in the following table:

	Year Ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
QEP Energy - Average field-level natural gas price (per Mcf)					
Northern Region	**$ 2.64**	$ 3.87	$ 4.11	**$ (1.23)**	$ (0.24)
Southern Region	**2.70**	4.00	4.24	**(1.30)**	(0.24)
Average field-level natural gas price	**2.68**	3.95	4.18	**(1.27)**	(0.23)
QEP Energy - Average field-level oil price (per bbl)					
Northern Region	**$ 83.03**	$ 84.88	$ 67.62	**$ (1.85)**	$ 17.26
Southern Region	**89.32**	90.45	74.93	**(1.13)**	15.52
Average field-level oil price	**84.45**	86.20	69.39	**(1.75)**	16.81
QEP Energy - Average field-level NGL price (per bbl)					
Northern Region	**$ 36.17**	$ 52.00	$ 54.62	**$ (15.83)**	$ (2.62)
Southern Region	**30.44**	43.66	35.57	**(13.22)**	8.09
Average field-level NGL price	**34.43**	47.76	39.04	**(13.33)**	8.72

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

	Year Ended December 31,			Change	
	2012 (1)	2011 (2)	2010 (2)	**2012 vs. 2011**	2011 vs. 2010
Natural gas (per Mcf)					
Average field-level price	**$ 2.68**	$ 3.95	$ 4.18	**$ (1.27)**	$ (0.23)
Commodity derivative impact	**1.37**	0.79	1.14	**0.58**	(0.35)
Net realized price	**$ 4.05**	$ 4.74	$ 5.32	**$ (0.69)**	$ (0.58)
Oil (per bbl)					
Average field-level price	**$ 84.45**	$ 86.20	$ 69.39	**$ (1.75)**	$ 16.81
Commodity derivative impact	**2.28**	0.43	(2.91)	**1.85**	3.34
Net realized price	**$ 86.73**	$ 86.63	$ 66.48	**$ 0.10**	$ 20.15
NGL (per bbl)					
Average field-level price	**$ 34.43**	$ 47.76	$ 39.04	**$ (13.33)**	$ 8.72
Commodity derivative impact	**1.90**	—	—	**1.90**	—
Net realized price	**$ 36.33**	$ 47.76	$ 39.04	**$ (11.43)**	$ 8.72
Average net equivalent price (per Mcfe)					
Average field-level price	**$ 4.34**	$ 5.04	$ 4.83	$ (0.70)	$ 0.21
Commodity derivative impact	**1.14**	0.68	0.98	0.46	(0.30)
Net realized price	**$ 5.48**	$ 5.72	$ 5.81	$ (0.24)	$ (0.09)

(1) The impact from commodity derivatives is reported below operating (loss) income in "Realized and unrealized gains on derivative contracts" beginning January 1, 2012, in the Consolidated Statement of Operations.

(2) For the years ended December 31, 2011 and 2010, the impact of settled commodity derivatives that qualified for hedge accounting was reported in "Revenues" in the Consolidated Statement of Operations. The impact of the commodity derivatives that did not qualify for hedge accounting was reported below operating (loss) income in "Realized and unrealized gains on derivative contracts."

Gathering

During the year ended December 31, 2012, QEP Field Services' gathering margins declined 7% primarily due to a decrease in other gathering revenue and the related margin from the elimination of a third-party interruptible processing agreement. Partially offsetting the decline in gathering margin was a 2% increase in gathering system throughput volume and a 3% increase in average gas gathering revenue per MMBtu during 2012. Gathering system throughput average volume was 1.4 million MMBtu per day for the year ended December 31, 2012. The 11.1 million MMBtu increase in gathering volumes were mainly related to increased gathering volumes at the Blacks Fork hub in southwest Wyoming and the northwest Louisiana gathering system, which were 2% higher and 12% higher, respectively, during 2012. During 2012, the gathering volume increase at the Blacks Fork hub was driven by a 17.5 million MMBtu increase in affiliated production at Pinedale offset by a 9.9 million MMBtu decrease in deliveries from unaffiliated customers. The Blacks Fork hub and the Hall Summit hub accounted for 51% and 23%, respectively, of the total gathering system throughput during 2012. QEP Field Services posted a 22% increase in gathering margin during 2011, primarily due to an increase in the NGL value received from a short-term, third-party processing arrangement for certain volumes in the Northern Region and a 3% increase in the average gathering rate. Gathering system throughput volume was 1.4 million MMBtu per day for 2011, up from the 1.3 million MMBtu per day during 2010. The increased volumes in 2011 were mainly related to the northwest Louisiana gathering system, as described above, which accounted for 21% and 16% of the total throughput during the years ended December 31, 2011 and 2010, respectively.

During the year ended December 31, 2011, QEP Field Services reported other gathering revenues and related gathering expense related to a short-term interruptible gas processing contract with a third-party processor. The short-term processing arrangement was in effect prior to the startup of QEP Field Services' Blacks Fork II processing plant. The $31.9 million decrease in other gathering revenues in 2012 was primarily related to the termination of this contract. In addition, gathering expenses related to the termination of this contract were $10.7 million lower during 2012.

The following tables are a summary of QEP Field Services' financial and operating results from gathering activities:

	Year Ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
Gathering Margin			(in millions)		
Gathering revenues	**$ 172.9**	$ 161.1	$ 152.5	**$ 11.8**	$ 8.6
Other gathering revenues	**36.6**	68.5	36.7	**(31.9)**	31.8
Gathering expense	**(37.4)**	(44.6)	(37.6)	**7.2**	(7.0)
Gathering margin	**$ 172.1**	$ 185.0	$ 151.6	**$ (12.9)**	$ 33.4
Operating Statistics					
Natural gas gathering volumes (in millions of MMBtu)					
For unaffiliated customers	**240.0**	261.2	276.8	**(21.2)**	(15.6)
For affiliated customers	**266.5**	234.2	198.9	**32.3**	35.3
Total gas gathering volumes	**506.5**	495.4	475.7	**11.1**	19.7
Average gas gathering revenue (per MMBtu)	**$ 0.34**	$ 0.33	$ 0.32	**$ 0.01**	$ 0.01

Processing

Although a significant portion of the QEP Field Services' gas processing services are performed for a volumetric-based fee, QEP Field Services also provides keep-whole processing services for certain customers which exposes the Company to the frac spread.

QEP Field Services' processing margin decreased 14% during the year ended December 31, 2012, due to a 35% decline in keep-whole processing margins, partially offset by a 40% increase in fee-based processing revenues. Processing margin increased 93% during 2011, compared to 2010, due to increased keep-whole processing margins and fee-based processing volumes and lower natural gas prices.

During the year ended December 31, 2012, the keep-whole processing margin per NGL barrel was $22.88 compared to $35.99 during the year ended December 31, 2011. The keep-whole processing margins decreased in 2012 due to a decrease in the net realized NGL sales price per bbl, partially offset by increased NGL sales volumes. Including the impact of gains on derivative contract settlements, NGL prices decreased 21% in 2012, which caused a corresponding decrease in the keep-whole processing margin per NGL bbl. NGL sales volumes increased 3% in 2012, primarily the result of the Blacks Fork II plant, which commenced operations in July 2011, partially offset by the execution, in the second quarter of 2012, of a fee-based processing agreement with QEP Energy in the Uinta Basin that effectively transferred NGL bbls from QEP Field Services to QEP Energy. The increased keep-whole processing margin in 2011 was the result of increased NGL prices and volume compared to 2010. NGL prices increased 34% and NGL volumes increased 42% during 2011 from 2010.

Fee-based processing revenues increased during the year ended December 31, 2012, due to a 27% increase in average fee-based processing revenue to $0.28 per MMBtu and a 4% increase in fee-based processing volumes to 251.3 million MMBtu. Fee-based processing revenues increased 53% during 2011, compared to 2010, due to a 6% increase in fee-based processing volumes to 240.7 million MMBtu and a 38% increase in the processing fee rate. The increased processing volume during the years ended December 31, 2012 and 2011, was primarily the result of the start-up of the 150 MMcf per day Iron Horse cryogenic processing plant in the Uinta Basin of eastern Utah during the first quarter of 2011 and the start-up of the Blacks Fork II plant in the third quarter of 2011. Approximately 77%, 70% and 78% of QEP Field Services' net operating revenue was derived from fee-based gathering and processing agreements in the years ended December 31, 2012, 2011 and 2010, respectively.

Keep-whole processing margin, as reflected in the table below, is defined as the market value for NGL extracted from the natural gas stream less the market value of the Btu-equivalent volume of natural gas required to replace the extracted liquids and the related transportation and handling (including fractionation) costs and less plant fuel and shrink. Transportation and handling costs were $24.3 million and $9.3 million higher during the years ended December 31, 2012 and 2011, respectively. The increase in these costs was primarily the result of additional transportation costs relating to NGL sale agreements that provide for transportation and fractionation of NGL at Mont Belvieu, Texas, and the full year operation of the Blacks Fork II plant, which was put into service in July of 2011.

The following tables are a summary of QEP Field Services' processing financial and operating results:

	Years ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
Processing Margin			(in millions)		
NGL sales [(1)]	**$ 137.9**	$ 180.0	$ 94.8	**$ (42.1)**	$ 85.2
Realized gains from commodity derivative contract settlements	**8.4**	—	—	**8.4**	—
Processing (fee-based) revenues	**69.6**	53.7	35.2	**15.9**	18.5
Other processing revenues	**8.9**	2.2	—	**6.7**	2.2
Processing expense	**(16.1)**	(12.2)	(11.9)	**(3.9)**	(0.3)
Processing plant fuel and shrink expense	**(33.3)**	(49.2)	(32.6)	**15.9**	(16.6)
Natural gas, oil and NGL transportation and other handling costs	**(33.6)**	(9.3)	—	**(24.3)**	(9.3)
Processing margin	**$ 141.8**	$ 165.2	$ 85.5	**$ (23.4)**	$ 79.7
Keep-whole processing margin	**$ 79.4**	$ 121.5	$ 62.2	**$ (42.1)**	$ 59.3

	Years ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
Operating Statistics					
Natural gas processing volumes					
NGL sales (Mbbl)	**3,470.3**	3,376.4	2,386.1	**93.9**	990.3
Average net realized NGL sales price (per bbl)[2]	**$ 42.18**	$ 53.33	$ 39.73	**$ (11.15)**	$ 13.60
Fee-based processing volumes (in millions of MMBtu)					
For unaffiliated customers	**108.2**	122.9	116.8	**(14.7)**	6.1
For affiliated customers	**143.1**	117.8	109.4	**25.3**	8.4
Total fee-based processing volumes	**251.3**	240.7	226.2	**10.6**	14.5
Average fee-based processing revenue (per MMBtu)	**$ 0.28**	$ 0.22	$ 0.16	**$ 0.06**	$ 0.06

(1) Revenues for the years ended December 31, 2011 and 2010, reflect the impact of QEP's settled derivative contracts which during the year ended December 31, 2012, are reflected below operating (loss) income. See Note 6 - Derivative Contracts, in Part II, Item 8 of this Annual Report on Form 10-K for detailed information on derivative contract settlements in the years ended December 31, 2012, 2011 and 2010.

(2) Average net realized NGL sales price per bbl is calculated as NGL sales including realized gains from commodity derivative contracts settlements divided by NGL sales volumes.

Revenue, Volume and Price Variance Analysis

On January 1, 2012, QEP discontinued hedge accounting. During the year ended December 31, 2012, commodity derivative realized gains and losses from derivative contract settlements are included below operating (loss) income in "Realized and unrealized gains on derivative contracts" on the Consolidated Statement of Operations. Conversely, during the years ended December 31, 2011 and 2010, the commodity derivative realized gains and losses on settlements were included in each respective revenue category in conjunction with hedge accounting and the realization of the underlying contract. For additional information regarding the discontinuance of hedge accounting and impact on the Consolidated Statement of Operations, see Note 6 - Derivative Contracts, in Part II, Item 8 of this Annual Report on Form 10-K.

The following table is a summary of QEP's total revenues:

	Years ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
			(in millions)		
QEP Resources Revenues					
Natural gas sales	**$ 667.4**	$ 1,239.1	$ 1,205.3	**$ (571.7)**	$ 33.8
Oil sales	**532.6**	324.2	198.1	**208.4**	126.1
NGL sales	**322.1**	309.8	142.6	**12.3**	167.2
Gathering, processing and other	**181.6**	200.8	156.6	**(19.2)**	44.2
Purchased gas, oil and NGL sales	**646.1**	1,085.3	598.0	**(439.2)**	487.3
Total Revenues	**$ 2,349.8**	$ 3,159.2	$ 2,300.6	**$ (809.4)**	$ 858.6

QEP Energy's price and volume related revenue variances are depicted in the following table:

	Natural Gas	Oil	NGL	Total
	(in millions)			
QEP Energy Production Revenues				
Year ended December 31, 2010 Revenues	$ 1,205.3	$ 198.1	$ 47.9	$ 1,451.3
Changes associated with volumes [1]	193.2	50.7	58.1	302.0
Changes associated with prices [2]	(159.4)	75.4	23.7	(60.3)
Year ended December 31, 2011 Revenues	1,239.1	324.2	129.7	1,693.0
Changes associated with volumes [1]	50.7	221.0	125.8	397.5
Changes associated with prices [2]	(316.9)	(11.0)	(71.3)	(399.2)
Changes associated with discontinuance of hedge accounting [3]	(305.5)	(1.6)	—	(307.1)
Year ended December 31, 2012 Revenues	**$ 667.4**	**$ 532.6**	**$ 184.2**	**$ 1,384.2**

(1) The revenue variance attributed to the change in volume is calculated by multiplying the change in volumes from the years ended December 31, 2012 and 2011, to the years ended December 31, 2011 and 2010, by the average field-level price for the years ended December 31, 2011 and 2010.

(2) The revenue variance attributed to the change in price is calculated by multiplying the change in field-level prices or fee from the years ended December 31, 2012 and 2011, to the years ended December 31, 2011 and 2010, by volume for the years ended December 31, 2011 and 2010. Pricing changes are driven by changes in the commodity field-level prices excluding impact from commodity derivatives.

(3) During the years ended December 31, 2011 and 2010, realized gains and losses on commodity derivative contract settlements were included in natural gas revenues on the Consolidated Statement of Operations. Conversely, during the year ended December 31, 2012, the realized gains and losses on commodity derivative contract settlements are recognized below operating (loss) income on the Consolidated Statement of Operations.

The following table presents changes in QEP Field Services' major revenue categories and the related volume and pricing impact:

	NGL	Processing	Gathering	Total
	(in millions)			
QEP Field Services				
Year ended December 31, 2010 Revenues	$ 94.8	$ 35.2	$ 189.2	$ 319.2
Changes associated with volumes [1]	39.3	2.5	6.6	48.4
Changes associated with prices/fees [2]	45.9	16.0	2.0	63.9
Changes associated with other factors [3]	—	2.2	31.8	34.0
Year ended December 31, 2011 Revenues	180.0	55.9	229.6	465.5
Changes associated with volumes [1]	5.0	2.4	3.6	11.0
Changes associated with prices/fees [2]	(47.3)	13.5	8.2	(25.6)
Changes associated with discontinuance of hedge accounting [4]	0.2	—	—	0.2
Changes associated with other factors [3]	—	6.7	(31.9)	(25.2)
Year ended December 31, 2012 Revenues	**$ 137.9**	**$ 78.5**	**$ 209.5**	**$ 425.9**

(1) The revenue variance attributed to the change in volume is calculated by multiplying the change in volumes from the years ended December 31, 2012 and 2011, to the years ended December 31, 2011 and 2010, by the average price or fee for the years ended December 31, 2011 and 2010.

(2) The revenue variance attributed to the change in fees is calculated by multiplying the change in prices or fees from the years ended December 31, 2012 and 2011, to the years ended December 31, 2011 and 2010, by volume for the year ended December 31, 2012 and 2011.

(3) The revenue variance attributed to the change associated with other factors represents the changes in other gathering revenues and changes in other processing revenues. These other revenues are not included in average gathering revenue per MMBtu or average fee-based processing revenue per MMBtu in QEP Field Services' operating statistics and thus have not been included in the price and volume variance analysis presented above.

(4) During the years ended December 31, 2011 and 2010, realized gains and losses on commodity derivative contract settlements were included in natural gas revenues on the Consolidated Statement of Operations. Conversely, during the year ended December 31, 2012, the realized gains and losses on commodity derivative contract settlements are recognized below operating (loss) income on the Consolidated Statement of Operations.

Purchased gas, oil and NGL sales decreased by $439.2 million, or 40%, during the year ended December 31, 2012, from the year ended December 31, 2011. The decrease in 2012, was due to decreased resale natural gas volumes and prices. Resale natural gas volumes were 33% lower during 2012, and resale natural gas prices were 39% lower during 2012. Purchased gas and oil sales increased by $487.3 million, or 81% during 2011 from 2010. The increase in 2011 was primarily due to QEP Energy's additional revenues of $509.8 million related to gas purchases made in northwest Louisiana to utilize firm transportation capacity and the subsequent sale of those gas purchases.

Operating Expenses

The following table presents QEP Resources' total operating expenses and the changes from the years ended December 31, 2012 and 2011, to the years ended December 31, 2011 and 2010. The narrative following the table explains the significant variances between the comparable periods.

	Years ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
			(in millions)		
Purchased gas, oil and NGL expense	**$ 655.6**	$ 1,077.1	$ 589.3	**$ (421.5)**	$ 487.8
Lease operating expense	**172.3**	145.2	125.0	**27.1**	20.2
Natural gas, oil and NGL transportation and other handling costs	**148.9**	102.2	54.2	**46.7**	48.0
Gathering, processing and other	**88.0**	107.3	83.2	**(19.3)**	24.1
General and administrative	**266.6**	123.2	107.2	**143.4**	16.0
Separation costs	**—**	—	13.5	**—**	(13.5)
Production and property taxes	**103.4**	105.4	82.5	**(2.0)**	22.9
Depreciation, depletion and amortization	**904.9**	765.4	643.4	**139.5**	122.0
Exploration expenses	**11.2**	10.5	23.0	**0.7**	(12.5)
Abandonment and impairment	**133.4**	218.4	46.1	**(85.0)**	172.3
Total operating expenses	**$ 2,484.3**	$ 2,654.7	$ 1,767.4	**$ (170.4)**	$ 887.3

Purchased gas, oil and NGL expense decreased 39% in 2012. The decrease during 2012 was due to 39% lower natural gas purchase prices and 28% lower natural gas purchased volumes. Purchased gas, oil and NGL expense increased in 2011 due to increased purchased gas expense at QEP Energy of $506.4 million. The increased purchased gas expense at QEP Energy relates to gas purchases made in northwest Louisiana to utilize firm transportation capacity.

Lease operating expense increased 19% during the year ended December 31, 2012, due to higher production volumes, increased water disposal costs, higher trucking, chemical, labor and pumper costs and increases in workover costs, well maintenance and repair expenses. Water disposal costs increased $9.3 million during 2012 primarily in the Northern Region due to increased drilling activity and related water disposal constraints in the Williston Basin. During 2012, produced water trucking, chemical, labor and pumper costs increased $9.8 million, respectively, primarily in the Northern Region due to increased drilling activity and liquids production in the Williston Basin. Workover costs and maintenance and repair expenses increased $3.8 million primarily related to the increased number of pumping oil wells located in the Northern Region. Lease operating expense increased $20.2 million, or 16%, to $145.2 million during 2011 compared to 2010 driven by a 20% increase in production of natural gas and oil and NGL equivalents during the period.

During the year ended December 31, 2012, natural gas, oil and NGL transportation and other handling costs increased $46.7 million when compared to the corresponding period in 2011 and increased $48.0 million during 2011, compared to the corresponding period in 2010. The increases during the years ended December 31, 2012 and 2011, are primarily due to higher production volumes, increased transportation costs relating to agreements that provide for transportation and fractionation of NGL at Mont Belvieu, Texas, and the 2012 operation of the Blacks Fork II plant which was put into service in the third quarter of 2011.

Gathering, processing and other expense decreased by $19.3 million for the year ended December 31, 2012, primarily due to a 32% reduction in the cost to purchase natural gas to replace the shrink caused by extracting natural gas liquids from the gas stream under QEP Field Services keep-whole processing activity. The decrease in shrink gas purchases was mainly due to QEP's processing plants running in ethane rejection (where instead of recovery, the ethane is left in the production stream and sold as natural gas) mode during the fourth quarter of 2012. In addition, gathering expenses were 16% lower from the elimination of a short-term interruptible processing agreement QEP Field Services entered into to process gas during the first half of 2011 before the expansion of the Blacks Fork processing plant that was put into service during the third quarter of 2011. Gathering, processing and other expense increased by $24.1 million in 2011 when compared to the 2010 period due to higher gathering and processing volumes and the effect from the short-term, third-party interruptible processing agreement in place during the first half of 2011.

During the year ended December 31, 2012, general and administrative (G&A) expense increased by $143.4 million, or 116%, compared to 2011. The largest portion of the increase in G&A during 2012 was due to the accrual of a $115 million litigation loss contingency (see Note 9 - Commitments and Contingencies, to the Consolidated Financial Statements of this Annual Report on Form 10-K). Additional factors contributing to the 2012 increase were $7.0 million in restructuring costs, $2.2 million pension curtailment related to the Company's restructuring efforts (see Note 7 - Restructuring Costs, to the Consolidated Financial Statements of this Annual Report on Form 10-K), $4.7 million in higher compensation costs due to increased number of employees and the annual compensation program, $2.5 million increase in pension and post-retirement medical expenses, $3.6 million increase in stock-based compensation expense, $1.4 million increase from the mark-to-market of the deferred compensation wrap plan, $7.1 million increase in professional and contract services, with the remaining increases related to various immaterial items. Total QEP G&A expense increased to $123.2 million for 2011 compared with $107.2 million for 2010. The increase in 2011 resulted from an increase in the number of employees, increased employee benefit plan and stock-based compensation related expenses, increased legal and outside professional services and higher insurance costs.

Production and property taxes decreased 2% during the year ended December 31, 2012. The decrease in 2012 was due to a 14% decrease in field-level equivalent sales prices which are used as the basis for production taxes in most states where QEP operates. Higher field-level oil and NGL prices resulted in higher production taxes during 2011, partially offset by lower field-level sales prices for natural gas during the same period.

During the year ended December 31, 2012, QEP's total depreciation, depletion and amortization (DD&A) expense increased $139.5 million, or 18%, as compared to 2011. The 2012 increase in DD&A expense was the result of increased production and increased DD&A rates at QEP Energy. Also contributing to the increase in DD&A expense during 2012 was the completion of the Blacks Fork II plant during the third quarter of 2011 at QEP Field Services. QEP's total DD&A expense grew $122.0 million, or 19%, in 2011 from the 2010 comparable period as a result of increased production at QEP Energy combined with plant additions at QEP Field Services.

Exploration expenses increased $0.7 million, or 7%, during the year ended December 31, 2012, compared with the 2011 period. The 2012 increase primarily related to an increase in seismic studies of $1.8 million partially offset by a $0.7 million decrease in exploration related labor and benefits costs as well as a $0.4 million decrease in exploration contract and consulting services. Exploration expenses were $10.5 million in 2011 compared to $23.0 million in 2010 due to a decrease in dry hole costs of $9.3 million and reduced seismic acquisition costs of $2.5 million.

Abandonment and impairment expenses decreased $85.0 million, to $133.4 million, during the year ended December 31, 2012. The decrease was primarily due to $195.5 million compared to $107.6 million of impairments recognized on proved properties in 2011 and 2012, respectively. The Company's proved properties have significant reserves and are sensitive to declines in natural gas, crude oil and NGL prices. These assets are at risk of impairment if future natural gas, crude oil or NGL prices experience significant declines. Abandonment and impairment expenses increased to $218.4 million during 2011, compared with $46.1 million during the 2010 period. The 2011 increase was primarily due to the recognition of a price-related impairment charge of $195.5 million in the fourth quarter of 2011 on some of the Company's mature, dry gas, and higher cost properties in both the Northern and Southern Regions.

CONSOLIDATED RESULTS BELOW OPERATING (LOSS) INCOME

Realized and unrealized gains on derivative contracts

Effective January 1, 2012, QEP discontinued hedge accounting, thus changes during the year ended December 31, 2012, and all changes in the mark-to-market value are recognized in current period earnings. Gains and losses on derivative instruments during 2012 are comprised of both realized and unrealized gains and losses on QEP's commodity derivative contracts and interest rate swaps. During 2012, gains on commodity derivative instruments were $449.3 million, of which $380.0 million was realized and $69.3 million was unrealized. Additionally, during 2012, losses from interest rate swaps were $7.4 million, of which $1.3 million was realized and $6.1 million was unrealized. During the years ended December 31, 2011 and 2010, QEP used hedge accounting and changes in the mark-to-market value of the commodity derivative contracts were reflected in accumulated other comprehensive income (AOCI) and ultimately revenues when the commodity derivatives were settled. As a result of discontinuing hedge accounting, the mark-to-market values at December 31, 2011, were fixed in AOCI as of the de-designation date and are being reclassified into the Consolidated Statement of Operations as the transactions settle and affect earnings. At December 31, 2012, AOCI consisted of $123.5 million ($77.6 million after tax) of unrealized gains. During 2012, $171.1 million unrealized gains, after tax, were reclassified from AOCI into the Consolidated Statement of Operations as the transactions settled. QEP expects to reclassify into earnings from AOCI the remaining fixed value related to de-designated natural gas, oil and NGL hedges during 2013.

Interest and other income

Interest and other income are comprised primarily of interest earned on investments, gains and losses on warehouse inventory, and other miscellaneous income. During 2012, interest and other income increased $2.5 million. The increase was primarily due to a $1.4 million increase in interest income and variances in warehouse inventory valuations of $0.8 million for 2012.

During 2011, interest and other income increased by $1.8 million, primarily due to the variance in inventory valuations, offset by lower gains on warehouse inventory sales.

Loss from early extinguishment of debt

During the year ended December 31, 2012, QEP recorded a loss from early extinguishment of debt of $0.6 million from the retirement of a portion of QEP's senior notes. During 2011, QEP recorded a loss from early extinguishment of debt of $0.7 million due to replacing the previous $1.0 billion revolving credit facility with a new $1.5 billion revolving credit facility in August 2011. The loss of $13.3 million during 2010 was the result of the repurchase of $638.0 million principal amount of senior notes and the termination of a $500 million term loan related to the Spin-off from Questar, both occurring in the third quarter of 2010.

Interest expense

Interest expense increased $32.9 million, or 37%, during the year ended December 31, 2012, compared to 2011. The increase in interest expense during 2012 was due to average debt levels that were approximately $856.5 million higher than average debt levels during 2011. The increase in average debt levels is related to QEP issuing 2022 Senior Notes and 2023 Senior Notes and entering into the Term Loan. Interest expense increased 7% to $90.0 million in 2011 compared to 2010 due to December 31, 2011, average debt levels that were approximately $165 million higher than average debt levels in the comparable prior period.

Income taxes

QEP's effective combined federal and state income tax rate was 33.5% during the year ended December 31, 2012, compared to 36.3% during 2011. The 2012 combined rate was lower due to state income tax adjustments to prior year provisions based on tax returns filed. The effective combined federal and state income tax rate was 36.3% for 2011, slightly lower than the 36.9% effective combined rate in 2010. The decrease in the combined rate during 2011 was primarily due to the Spin-off which increased the 2010 rate.

DISCUSSION BY LINE OF BUSINESS

QEP Energy

QEP Energy reported a net loss of $0.7 million during the year ended December 31, 2012, a decrease of $105.4 million from the $104.7 million net income reported during the year ended December 31, 2011. The decrease in 2012 was primarily due to the accrual of a $115 million litigation loss contingency, 4% lower average total equivalent net realized prices, and a 18% increase in DD&A, partially offset by an unrealized gain from commodity derivative contracts of $68.4 million and increased production. QEP Energy reported net income of $104.7 million in 2011, a decrease of 49% from $203.9 million in 2010. The primary reason for the decrease in 2011 net income was the recognition of a price-related impairment charge of $195.5 million in the fourth quarter of 2011 on some of QEP Energy's mature, dry gas, and higher cost properties in both the Northern and Southern Regions.

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

	Year Ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
	(in millions)				
Revenues					
Natural gas sales	**$ 667.4**	$ 1,239.1	$ 1,205.3	**$ (571.7)**	$ 33.8
Oil sales	**532.6**	324.2	198.1	**208.4**	126.1
NGL sales	**184.2**	129.7	47.9	**54.5**	81.8
Purchased gas, oil and NGL sales	**222.0**	509.8	—	**(287.8)**	509.8
Other	**9.2**	10.4	5.0	**(1.2)**	5.4
Total Revenues	**1,615.4**	2,213.2	1,456.3	**(597.8)**	756.9
Operating expenses					
Purchased gas, oil and NGL expense	**224.7**	506.4	—	**(281.7)**	506.4
Lease operating expense	**175.8**	148.2	127.3	**27.6**	20.9
Natural gas, oil and NGL transportation and other handling costs	**228.1**	186.0	125.5	**42.1**	60.5
General and administrative	**237.6**	98.4	78.0	**139.2**	20.4
Production and property taxes	**97.2**	99.1	77.8	**(1.9)**	21.3
Depreciation, depletion and amortization	**838.0**	707.2	592.5	**130.8**	114.7
Exploration expenses	**11.2**	10.5	23.0	**0.7**	(12.5)
Abandonment and impairment	**133.4**	218.4	46.1	**(85.0)**	172.3
Total Operating Expenses	**1,946.0**	1,974.2	1,070.2	**(28.2)**	904.0
Net gain from asset sales	**1.2**	1.4	13.7	**(0.2)**	(12.3)
Operating (Loss) Income	**(329.4)**	240.4	399.8	**(569.8)**	(159.4)
Realized gain (loss) on derivative instruments	**366.5**	(117.7)	(121.7)	**484.2**	4.0
Unrealized gain on derivative instruments	**68.4**	117.7	121.7	**(49.3)**	(4.0)
Interest and other income	**6.2**	4.0	2.1	**2.2**	1.9
Income from unconsolidated affiliates	**0.1**	0.1	0.2	**—**	(0.1)
Interest expense	**(116.8)**	(81.9)	(78.5)	**(34.9)**	(3.4)
(Loss) Income before Income Taxes	**(5.0)**	162.6	323.6	**(167.6)**	(161.0)
Income tax benefit (provision)	**4.3**	(57.9)	(119.7)	**62.2**	61.8
Net (Loss) Income Attributable to QEP	**$ (0.7)**	$ 104.7	$ 203.9	**$ (105.4)**	$ (99.2)

Operating expenses per unit

QEP Energy's total operating expenses (the sum of DD&A expense, lease operating expense, natural gas, oil and NGL transportation and other handling costs, G&A expense, a portion of QEP's total interest expense that is allocated to QEP Energy based on intercompany agreements and production taxes) per Mcfe of production increased 10% to $5.30 per Mcfe during

2012, compared to $4.81 per Mcfe during 2011. Operating expenses per Mcfe of production increased 2% to $4.81 per Mcfe during 2011, versus $4.72 per Mcfe in 2010.

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

	Year Ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
			(per Mcfe)		
Depreciation, depletion and amortization	**$ 2.63**	$ 2.57	$ 2.59	**$ 0.06**	$ (0.02)
Lease operating expense	**0.55**	0.54	0.56	**0.01**	(0.02)
Natural gas, oil and NGL transportation and other handling costs	**0.71**	0.68	0.55	**0.03**	0.13
General and administrative	**0.74**	0.36	0.34	**0.38**	0.02
Allocated interest expense	**0.37**	0.30	0.34	**0.07**	(0.04)
Production taxes	**0.30**	0.36	0.34	**(0.06)**	0.02
Total Operating Expenses	**$ 5.30**	$ 4.81	$ 4.72	**$ 0.49**	$ 0.09

DD&A expense increased $0.06 per Mcfe during the year ended December 31, 2012, when compared to the year ended December 31, 2011. The increase in DD&A expense per Mcfe was the result of increased production from higher-rate DD&A pools and increases in the DD&A rates from increased drilling costs in the Midcontinent and the Williston Basin. DD&A expense per Mcfe decreased $0.02 in 2011 from the 2010 period. QEP Energy's DD&A expense increased $114.7 million during 2011 from 2010. While QEP Energy's total DD&A increased in 2011, the lower per unit expense in 2011 was the result of booking NGL reserves associated with the fee-based processing agreement entered into between QEP Energy and QEP Field Services for QEP's Pinedale production.

QEP Energy's average production costs (lease operating expense) per Mcfe were 2% higher during the year ended December 31, 2012, compared to the year ended December 31, 2011. Average production costs per Mcfe were 4% lower in the 2011 period compared to the 2010 period.

The following table presents average production cost, excluding production taxes, for QEP Energy by region on a unit of production basis:

	Year Ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
			(per Mcfe)		
Northern Region	**$ 0.63**	$ 0.58	$ 0.56	**$ 0.05**	$ 0.02
Southern Region	**0.47**	0.50	0.55	**(0.03)**	(0.05)
Average production cost	**0.55**	0.54	0.56	**0.01**	(0.02)

Lease operating expense per Mcfe increased $0.01 during the year ended December 31, 2012, when compared to the year ended December 31, 2011. The increase during 2012 in lease operating expense is primarily due to a $0.05 per Mcfe increase in the Northern Region, which was mostly offset by a $0.03 per Mcfe decrease in the Southern Region. The Northern Region increase was driven by a 41% increase in lease operating expenses, partially offset by a 30% increase in production. Lease operating expense increase in the Northern Region was primarily the result of higher water injection and disposal costs, increased trucking, chemical, labor and pumper costs and increases in workover costs and well maintenance and repair expenses. The Southern Region decrease was a result of a 5% increase in production and a 2% decrease in lease operating expenses. The decrease in lease operating expenses in the Southern Region was driven primarily by decreases in workover costs and well maintenance and repair expenses. Lease operating expense per Mcfe decreased $0.02 for 2011 from the 2010 period as the result of increased production volumes in lower cost areas. Growing production from new high-rate, low-operating cost wells in the Haynesville/Cotton Valley area and in the Pinedale Anticline, coupled with declining production from older higher cost areas, reduced average per Mcfe lease operating expense in 2011. For additional information regarding the variances in production and lease operating expenses, see "Production" and "Operating Expenses" discussions earlier in Item 7 of Part II in this Annual Report on Form 10-K.

Natural gas, oil and NGL transportation and other handling costs per Mcfe were 4% higher during the year ended December 31, 2012, than in the year ended December 31, 2011. The per Mcfe increase in 2012 relates to NGL sale agreements at Mont

Belvieu, Texas, and the related transportation and processing of NGL, which were effective beginning with the startup of the Blacks Fork II plant in the third quarter of 2011. Natural gas, oil and NGL transportation and other handling costs per Mcfe were 24% higher in 2011 than in 2010 due primarily to processing costs associated with increased NGL production and related transportation costs under a revised processing agreement at Pinedale.

G&A expense increased $0.38 per Mcfe during the year ended December 31, 2012. The per Mcfe increase in 2012 was the result of higher total G&A expenses during 2012, partially offset by increased production during the same period. The increased G&A expenses for 2012 was primarily the result of the accrual of a $115 million litigation loss contingency (See Note 9 - Commitments and Contingencies, to the consolidated financial statements in Item 8 of Part II of this Annual Report on Form 10-K). Excluding the litigation loss contingency accrual, G&A was $0.38 per Mcfe, an increase of $0.02 per Mcfe, or 6%, driven by expenses incurred in the current year for restructuring costs, higher compensation costs due to increased headcount and the annual compensation program, increases in pension and post-retirement medical expenses, increases in professional and contract services, increased stock-based compensation expense and mark-to-market changes in the Company's deferred compensation wrap plan (See Note 7 – Restructuring Costs, to the consolidated financial statements in Item 8 of Part II of this Annual Report on Form 10-K for additional information regarding restructuring costs). G&A expense per Mcfe increased $0.02 during the year ended December 31, 2011, as a result of higher G&A expenses, which were primarily related to employee benefit plan and stock-based compensation related expenses, increased legal and outside professional services and higher insurance costs, which were partially offset by increased production in 2011.

Allocated interest expense per Mcfe increased $0.07 during the year ended December 31, 2012. The increase during 2012 was primarily due to an increase in allocated interest expense resulting from higher debt levels. Allocated interest expense per unit of production decreased $0.04 per Mcfe in 2011 primarily due to higher production volumes.

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 taxes per Mcfe decreased by $0.06 during 2012 because of lower field-level natural gas, oil and NGL prices. Production taxes per Mcfe increased by $0.02 per Mcfe during 2011 because of higher field-level oil and NGL prices.

QEP Field Services

QEP Field Services, which provides gas gathering and processing services, generated net income of $129.0 million during the year ended December 31, 2012, compared to $154.5 million in the same period of 2011. During 2012, lower gathering and processing margins contributed to the 17% decrease in net income during 2012. Gathering margins were lower during 2012 as the result of decreased other gathering revenue due to the elimination of a short-term, third-party interruptible processing agreement. The short-term processing arrangement was in effect during the first three quarters of 2011, before the expansion of the Blacks Fork processing complex was put into service during the third quarter of 2011. Processing margins were lower during 2012, due to a decrease in NGL prices and the related impact of lower keep-whole processing margins. QEP Field Services generated net income of $154.5 million in the year ended December 31, 2011, compared to $91.1 million in 2010, a 70% increase. The increase in net income in 2011 was the result of higher gathering and processing margins and increased throughput volumes.

The following table provides a summary of QEP Field Services' financial and operating results:

	Year Ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
			(in millions)		
Revenues					
NGL sales	**$ 137.9**	$ 180.0	$ 94.8	**$ (42.1)**	$ 85.2
Processing (fee-based)	**69.6**	53.7	35.2	**15.9**	18.5
Other processing revenues	**8.9**	2.2	—	**6.7**	2.2
Gathering	**172.9**	161.1	152.5	**11.8**	8.6
Other gathering	**36.6**	68.5	36.7	**(31.9)**	31.8
Purchased gas, oil and NGL sales	**13.3**	—	—	**13.3**	—
Total Revenues	**439.2**	465.5	319.2	**(26.3)**	146.3
Operating expenses					
Purchased gas, oil and NGL expense	**12.1**	—	—	**12.1**	—
Processing	**16.1**	12.2	11.9	**3.9**	0.3
Processing plant fuel and shrinkage	**33.3**	49.2	32.6	**(15.9)**	16.6
Gathering	**37.4**	44.6	37.6	**(7.2)**	7.0
Natural gas, oil and NGL transportation and other handling costs	**33.6**	9.3	—	**24.3**	9.3
General and administrative	**34.7**	29.2	31.6	**5.5**	(2.4)
Taxes other than income taxes	**6.0**	6.1	4.4	**(0.1)**	1.7
Depreciation, depletion and amortization	**63.2**	55.7	48.9	**7.5**	6.8
Total Operating Expenses	**236.4**	206.3	167.0	**30.1**	39.3
Net gain from asset sales	**—**	—	(1.6)	**—**	1.6
Operating Income	**202.8**	259.2	150.6	**(56.4)**	108.6
Interest and other income	**0.2**	0.1	0.1	**0.1**	—
Income from unconsolidated affiliates	**6.7**	5.4	2.8	**1.3**	2.6
Realized gains on derivative instruments	**8.4**	—	—	**8.4**	—
Unrealized gains on derivative instruments	**—**	—	—	**—**	—
Interest expense	**(13.6)**	(13.6)	(7.6)	**—**	(6.0)
Income before Income Taxes	**204.5**	251.1	145.9	**(46.6)**	105.2
Income tax provision	**(71.8)**	(93.4)	(51.9)	**21.6**	(41.5)
Net income	**132.7**	157.7	94.0	**(25.0)**	63.7
Net income attributable to noncontrolling interest	**(3.7)**	(3.2)	(2.9)	**(0.5)**	(0.3)
Net Income Attributable to QEP	**$ 129.0**	$ 154.5	$ 91.1	**$ (25.5)**	$ 63.4

See "Gathering" and "Processing" sections, as appearing earlier, for additional discussion of the significant changes in QEP Field Services' comparative financial statements.

Natural gas, oil and NGL transportation and other handling costs increased $24.3 million and $9.3 million during the years ended December 31, 2012 and 2011, when compared to the prior year periods. The increase during the years ended December 31, 2012 and 2011, was primarily due to transportation costs related to the Blacks Fork II plant, placed into service in the third quarter of 2011, and the related transportation of additional NGL volumes to Mont Belvieu, Texas.

General and administrative expenses increased by $5.5 million during the year ended December 31, 2012. The increase in G&A costs during the current period was primarily due to increases in headcount and related compensation costs, increases in pension and post-retirement medical expenses, increases in stock compensation expense, and an increase in the mark-to-market value of the deferred compensation wrap plan. G&A expensed decreased $2.4 million in 2011 compared to 2010 primarily due to lower outside service costs.

During the year ended December 31, 2012, DD&A expense grew $7.5 million, or 13%, as compared to 2011. The 2012 increase in DD&A expense was primarily due to the completion of the Blacks Fork II plant during the third quarter of 2011 at QEP Field Services. DD&A expense grew $6.8 million, or 14%, in 2011 from the 2010 comparable period as a result of plant additions at QEP Field Services.

See "Consolidated Results Below Operating (Loss) Income" section, as appearing earlier, for additional discussion of the significant changes in such line items.

QEP Marketing and Other

QEP Marketing, which markets affiliate and third-party natural gas and oil and owns and operates a gas storage facility, generated no net income during the year ended December 31, 2012, an $8.0 million decrease from the $8.0 million of income during the year ended December 31, 2011. The decrease in net income in 2012 related to lower marketing margins and higher unrealized losses from derivative contracts. Also contributing to the decrease was higher interest expense in 2012 compared to 2011 due to higher average debt levels in the current year. During 2012, QEP Marketing had a loss on resale gas, oil and NGL of $8.0 million, related to fulfillment of firm transportation contract commitments. QEP Marketing generated net income from continuing operations of $8.0 million during 2011 compared with a loss of $12.0 million during 2010. The increase in 2011 was due to a 54% increase in marketing sales volumes, partially offset by a 5% decrease in marketing margins.

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

	Year Ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
			(in millions)		
Revenues					
Purchased gas, oil and NGL sales	**$ 1,013.1**	$ 1,149.3	$ 1,091.5	**$ (136.2)**	$ 57.8
Other	**6.8**	7.6	7.0	**(0.8)**	0.6
Total Revenues	**1,019.9**	1,156.9	1,098.5	**(137.0)**	58.4
Operating expenses					
Purchased gas, oil and NGL expense	**1,021.1**	1,144.5	1,082.8	**(123.4)**	61.7
Gathering, processing and other	**1.2**	1.3	1.1	**(0.1)**	0.2
General and administrative	**0.4**	2.1	3.9	**(1.7)**	(1.8)
Separation costs	**—**	—	13.5	**—**	(13.5)
Production and property taxes	**0.2**	0.2	0.3	**—**	(0.1)
Depreciation, depletion and amortization	**3.7**	2.5	2.0	**1.2**	0.5
Total Operating Expenses	**1,026.6**	1,150.6	1,103.6	**(124.0)**	47.0
Net gain from asset sales	**—**	—	—	**—**	—
Operating (Loss) Income	**(6.7)**	6.3	(5.1)	**(13.0)**	11.4
Realized gain on derivative instruments	**3.8**	—	—	**3.8**	—
Unrealized loss on derivative instruments	**(5.2)**	—	—	**(5.2)**	—
Interest and other income	**132.1**	98.7	87.2	**33.4**	11.5
Loss on extinguishment of debt	**(0.6)**	(0.7)	(13.3)	**0.1**	12.6
Interest expense	**(124.4)**	(93.2)	(85.4)	**(31.2)**	(7.8)
(Loss) Income before Income Taxes	**(1.0)**	11.1	(16.6)	**(12.1)**	27.7
Income tax benefit (provision)	**1.0**	(3.1)	4.6	**4.1**	(7.7)
Net (Loss) Income Attributable to QEP	**$ —**	$ 8.0	$ (12.0)	**$ (8.0)**	$ 20.0

Interest and other income primarily relates to intercompany debt agreements between QEP and its subsidiaries, which is eliminated in consolidation.

LIQUIDITY AND CAPITAL RESOURCES

QEP seeks to fund its development projects by employing a capital structure and financing strategy to provide sufficient liquidity to withstand commodity price swings. As part of this strategy QEP funds long-term capital intensive development projects while maintaining the ability to employ an exploration program, execute acquisitions and maintain an appropriate debt rating. In addition, QEP maintains a commodity price derivative strategy to reduce commodity price volatility and to provide certainty to cash flows.

QEP funds its operations, capital expenditures and working capital requirements with cash flow from its operating activities and borrowings under its credit facilities. Periodically, QEP's access to debt and capital markets and sales of assets will provide additional liquidity. The Company believes cash flow from operations and availability under its credit facility will be sufficient to fund the Company's planned capital expenditures and operating expenses during the next 12 months. To the extent actual operating results differ from the Company's estimates, QEP's liquidity could be adversely affected.

The following table provides QEP's available liquidity and debt to total capital ratio compared to the previous period:

	December 31,	
	2012	2011
	(in millions, except %)	
Cash and cash equivalents	**$ —**	$ —
Amount available under the revolving credit facility [(1)]	**805.9**	889.4
Total liquidity	**$ 805.9**	$ 889.4
Total debt [(2)]	**$ 3,206.9**	$ 1,679.4
Total common shareholders' equity	**3,266.0**	3,301.5
Ratio of debt to total capital [(3)]	**50%**	34%

(1) See discussion of the Company's revolving credit facility below. Includes outstanding letters of credit of $4.1 million for both the years ended December 31, 2012 and 2011.
(2) Includes all outstanding debt, which is discussed in detail below. At December 31, 2012, debt levels were higher than at December 31, 2011, primarily due to the 2012 Acquisition.
(3) Defined as total debt divided by the sum of total debt plus common shareholders' equity.

Credit Facility
QEP's revolving credit facility agreement, which matures in August 2016, provides for unsecured loan commitments of $1.5 billion from a syndicate of financial institutions. The credit facility provides for borrowings at short-term interest rates and contains customary covenants and restrictions. The credit facility agreement also contains provisions which would allow for the amount of the facility to be increased to $2.0 billion and for the maturity to be extended for two additional one-year periods with the agreement of the lenders. QEP's weighted-average interest rate on borrowings from its credit facility was 2.08% during the year ended December 31, 2012. At December 31, 2012, QEP was in compliance with the debt covenants under the credit agreement. At February 13, 2013, QEP had $731.5 million outstanding and $4.1 million of letters of credit issued under its credit facility.

Term Loan
During the second quarter of 2012, the Company entered into a $300.0 million Term Loan with a group of financial institutions. The Term Loan agreement provides for unsecured borrowings at short-term interest rates and contains covenants, restrictions and interest rates that are substantially the same as the Company's revolving credit facility. The Term Loan matures in April 2017, and the maturity date may be extended one year with the agreement of the lenders. The proceeds from the Term Loan were used to pay down the Company's credit facility and for general corporate purposes. During the year ended December 31, 2012, QEP's weighted-average interest rate on the Term Loan was 2.05%. In conjunction with the Term Loan, QEP entered into interest rate swap contracts with a combined notional principal amount of $300.0 million which will mature in March 2017. Under the swap contracts, QEP pays 1.07% for the life of the swaps and receives one-month LIBOR. The interest rate at December 31, 2012, under the Term Loan is one-month LIBOR, plus 2.00% (the Applicable Margin) which, when combined with the fixed interest rate swaps, results in a current effective rate of 3.07% for borrowings under the Term Loan. To the extent that the Applicable Margin under the Term Loan changes, the effective fixed rate paid for borrowings under the Term Loan will change.

Senior Notes
During the first quarter of 2012, the Company completed a public offering of $500.0 million in aggregate principal amount of 5.375% senior notes due in October 2022. The proceeds from the 2022 Senior Notes were used to repay indebtedness under the Company's credit facility. In the second quarter of 2012, the Company purchased $6.7 million of its senior notes outstanding due April 2018 and March 2020. In addition, during the third quarter of 2012, the Company completed a public offering of $650.0 million in aggregate principal amount of 5.25% senior notes due in May 2023. The proceeds from the 2023 Senior Notes were used to finance a portion of the 2012 Acquisition.

The Company's senior unsecured notes outstanding as of December 31, 2012, 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.

Cash Flow from Operating Activities

Cash flows from operating activities are primarily affected by natural 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 future gas, oil and NGL production for the next 12 to 24 months.

Net cash provided by operating activities increased $3.4 million during the year ended December 31, 2012, when compared to the year ended December 31, 2011, due to an increase in cash from operating assets and liabilities, offset by lower net income and reduced non-cash adjustment to net income. Non-cash adjustments to net income consisted primarily of DD&A; abandonment and impairment charges; unrealized gains on derivative contracts; and changes in deferred income taxes. Changes in operating assets and liabilities were a source of cash during 2012, primarily due to a decrease in accounts receivable and an increase in accrued expenses from the accrual of $115 million for litigation loss contingency. Changes in operating assets and liabilities driving a use of cash during 2011, were increases in accounts receivable, offset by increases in accounts payable.

Net cash provided from operating activities is presented below:

	Year Ended December 31,			Change	
	2012	2011	2010	**2012 vs. 2011**	2011 vs. 2010
	(in millions)				
Net income [(1)]	**$ 132.0**	$ 270.4	$ 285.9	$ (138.4)	$ (15.5)
Non-cash adjustments to net income	**1,038.0**	1,050.9	784.5	(12.9)	266.4
Changes in operating assets and liabilities	**126.0**	(28.7)	(72.9)	154.7	44.2
Net cash provided from operating activities	**$ 1,296.0**	$ 1,292.6	$ 997.5	$ 3.4	$ 295.1

(1) The net income for the year ended December 31, 2010, excludes discontinued operations, net of income tax, of $43.2 million.

Cash Flow from Investing Activities

A comparison of capital expenditures for the years ended December 31, 2012, 2011 and 2010, and a forecast for calendar year 2013 are presented in the table below:

	2013 Forecast[1]	Year Ended December 31, 2012	2011	2010	Change 2012 vs. 2011	2011 vs. 2010
		(in millions)				
QEP Energy	$ 1,530.0	**$ 2,702.4**	$ 1,338.8	$ 1,215.8	**$ 1,363.6**	$ 123.0
QEP Field Services	120.0	**171.2**	101.6	268.2	**69.6**	(166.6)
QEP Marketing	1.0	**1.0**	0.4	1.9	**0.6**	(1.5)
Corporate	25.0	**13.6**	5.0	—	**8.6**	5.0
Total accrued capital expenditures	1,676.0	**2,888.2**	1,445.8	1,485.9	**1,442.4**	(40.1)
Change in accruals	—	**(88.5)**	(14.7)	(16.9)	**(73.8)**	2.2
Total cash capital expenditures	$ 1,676.0	**$ 2,799.7**	$ 1,431.1	$ 1,469.0	**$ 1,368.6**	$ (37.9)

(1) Represents the mid-point end of the most recent guidance.

During the year ended December 31, 2012, capital expenditures on a cash basis increased 96% to $2,799.7 million, compared to $1,431.1 million during the year ended December 31, 2011. The increase of $1,368.6 million cash capital expenditures during 2012 was primarily the result of QEP Energy's $1,388.7 million 2012 Acquisition. Excluding the 2012 Acquisition, QEP's capital expenditures were $20.1 million lower than in 2011. Capital expenditures on a cash basis decreased in 2011 compared to 2010 due to completion in 2010 of capital projects for QEP Field Services.

QEP Energy's capital investment, on an accrual basis, during the year ended December 31, 2012, increased $1,363.6 million over the year ending December 31, 2011, due to increased capital expenditures in the Williston Basin (primarily due to the 2012 Acquisition), partially offset by lower capital expenditures in Haynesville (approximately 81% lower) due to the reduced drilling program as capital was allocated out of the dry-gas Haynesville play into higher-return oil and liquids-rich natural gas drilling programs. QEP Energy's capital investments for 2011 were higher than 2010 due to increased company operated well completions combined with acquisitions of additional working interests.

QEP Field Services' capital investment increased $69.6 million, on an accrual basis, during the year ended December 31, 2012, compared to 2011, due to projects directed to grow the midstream business. These projects include the construction of a 150 MMcfd fee-based cryogenic gas processing plant in the Uinta Basin (Iron Horse II) and the 10,000 Bbl/d expansion to the NGL fractionation facilities located at the Blacks Fork processing complex. QEP Field Services' capital investments decreased in 2011 compared to 2010 due to the completion of major capital projects in eastern Utah and northwest Louisiana in late 2010 and the completion of the Black Forks II plant early in the third quarter of 2011.

At December 31, 2012, forecasted capital investment for 2013 is expected to be approximately $1,676.0 million, comprised of $1,530.0 million allocated to QEP Energy, $120.0 million to QEP Field Services, and $26.0 million between QEP Resources and QEP Marketing. During 2013, QEP intends to fund capital expenditures with cash flow from operating activities and, if needed, borrowings under its credit facility. As a result of the continued low natural gas prices, QEP plans to decrease capital expenditures for the Haynesville Shale and other dry-gas development areas and increase capital expenditures for higher return projects, including Pinedale, Uinta Basin Red Wash Mesaverde, and oil-directed horizontal drilling in the Williston Basin, Powder River Basin and Midcontinent during 2013. QEP Energy has allocated approximately 98% of its 2013 total forecasted capital expenditure budget to crude oil and liquids-rich natural gas plays. QEP plans to invest a total of approximately $120.0 million in capital expenditures during 2013 to grow its midstream business, including the expansion of its gathering system in the Uinta Basin as well as the completion of a 10,000 Bbl/d expansion of the NGL fractionation facility located at the Blacks Fork processing complex (expected to be completed in the second half of 2013). QEP Resources plans to invest approximately $25.0 million in capital expenditures related to corporate activities, primarily the implementation of a new Enterprise Resource Planning system. The aggregate levels of capital expenditures for 2013 and the allocation of those expenditures are dependent on a variety of factors, including drilling results, natural gas and oil 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, 2012, net cash proceeds from financing activities was $1,498.5 million compared to $130.3 million during the year ended December 31, 2011. During 2012, QEP completed public offerings of $650.0 million and $500.0 million of senior notes and entered into a $300.0 million Term Loan. QEP had borrowings from its credit facility of $1,234.5 million and repayments on its credit facility of $1,151.0 million. In addition, QEP retired $6.7 million of its outstanding senior notes. During the years ended December 31, 2012, 2011 and 2010, QEP paid dividends of $14.2 million, $14.1 million and $7.0 million, respectively. In 2012, 2011 and 2010, QEP paid long-term debt issuance costs of $17.8 million, $10.6 million and $16.6 million, respectively. At December 31, 2012, long-term debt consisted of $690.0 million outstanding under its credit facility, $300.0 million under the Term Loan and $2,221.8 million in senior notes (excluding $4.9 million of net original issue discount).

During the year ended December 31, 2011, net cash used in investing activities of $1,422.9 million exceeded net cash provided by operating activities of $1,292.6 million by $130.3 million. For 2011, long-term debt increased by a net change of $207.1 million while short-term debt decreased by $58.5 million. All intercompany loans between Questar and QEP, which were historically reported as notes payable in the Consolidated Balance Sheets, were repaid on June 30, 2010, in conjunction with the Spin-off.

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, 2012, 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.

Settlement Agreement

On February 13, 2013, QEP executed the Chieftain Settlement Agreement, which provides for a cash settlement payment from QEP in the amount of $115 million in exchange for a full release of all claims regarding the calculation, reporting and payment of royalties from the sale of natural gas and its constituents for all periods prior to February 28, 2013. At December 31, 2012, QEP has recorded an accrual of $115.0 million based on the January 2013 mediation and resulting Chieftain Settlement Agreement. The Court has entered a Preliminary Order Approving Class Action Settlement. The payment of the $115 million settlement amount will be made into escrow before the end of February 2013.

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, 2012:

	Payments Due by Year [3]						
	Total	2013	2014	2015	2016	2017	After 2017
	(in millions)						
Long-term debt	$ 3,211.8	$ —	$ —	$ —	$ 866.8	$ 300.0	$ 2,045.0
Interest on fixed-rate, long-term debt [1]	1,122.7	133.0	133.0	133.0	129.5	122.3	471.9
Drilling contracts	109.6	69.7	37.0	2.9	—	—	—
Firm transportation and storage	347.5	45.2	44.2	44.1	42.6	42.0	129.4
NGL transportation	376.1	32.4	44.8	44.8	44.8	44.8	164.5
Fractionation	186.7	14.0	20.2	20.2	20.2	20.2	91.9
Asset Retirement Obligations [2]	193.1	1.7	3.7	2.6	2.9	2.2	180.0
Operating leases	62.1	6.7	6.5	6.6	6.5	6.7	29.1
Total	$ 5,609.6	$ 302.7	$ 289.4	$ 254.2	$ 1,113.3	$ 538.2	$ 3,111.8

[1] Excludes variable rate debt interest payments related to the Company's credit facility and Term Loan.
[2] These future obligations are discounted estimates of future expenditures based on expected settlement dates. See Item 8 of Part II of this Annual Report on Form 10-K, Note 4 - Asset Retirement Obligations, for additional information.
[3] This table excludes the Company's benefit plan liabilities as future payment dates are unknown. See Item 8 of Part II of this Annual Report on Form 10-K, Note 11 - Employee Benefits, for additional information.

Impact of Inflation and Pricing

QEP deals in U.S. dollars. Inflation in the context of oil field services and goods has been significant in primary areas in which QEP operates. Typically, as prices for oil and natural gas increase, associated costs rise. Conversely, cost declines are likely to lag and may not adjust downward in proportion to declining prices. Changes in prices impact QEP's revenues, estimates of reserves, assessments of any impairment of oil and natural 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 from where they are today, higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

Critical Accounting Policies, and Estimates

QEP's significant accounting policies are described in Note 1 to the consolidated financial statements included 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 U.S. Generally Accepted Accounting Principles. 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 accounting policies may involve a higher degree of complexity and judgment on the part of management.

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

Estimates of proved gas and oil reserves significantly affect the Company's DD&A expense. For example, if estimates of proved reserves decline, the 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 crude oil and natural gas properties exceeds fair value and could result in an impairment charge, which would reduce earnings.

QEP Energy engages an independent reservoir engineering consultant to prepare estimates of the proved gas and oil 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 17 - Supplemental Oil and Gas Information (Unaudited), of Item 8 of this Annual Report on Form 10-K.

Successful Efforts Accounting for Gas and Oil Operations

The Company follows the successful efforts method of accounting for gas and oil 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, the delay rental 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. Capitalized costs of unproved properties are reclassified as proved property when related proved reserves are determined or charged against the impairment allowance when abandoned.

Capitalized proved property acquisition costs are amortized by field using the unit-of-production method based on proved reserves. Capitalized exploratory well and development costs are amortized similarly by field based on proved developed reserves. The calculation takes into consideration estimated future equipment dismantlement, surface restoration and property abandonment costs, net of estimated equipment salvage values. Other property and equipment are generally depreciated using the straight-line method over estimated useful lives or the unit-of-production method for certain processing plants. A gain or loss is generally recognized only when an entire field is sold or abandoned, or if the unit-of-production amortization rate would be significantly affected.

Impairment of Oil and Gas Properties

Proved gas and oil 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 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 gas and oil reserves caused by mechanical problems, faster-than-expected decline of reserves, lease-ownership issues, other-than-temporary decline in natural gas, NGL and crude oil prices and changes in the utilization of midstream gathering and processing assets. 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. Management's assessment of the results of exploration activities and availability of funds for future activities also impact the amounts and timing of impairment provisions. During the years ended December 31, 2012, 2011 and 2010, QEP recorded impairment charges of $107.6 million, $195.5 million and $0.7 million, respectively, on some of its higher cost, proven properties in both Regions. The impairment charge related to the reduced value of these areas resulting from lower spot prices and lower forward curve 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, 2012, 2011 and 2010, QEP recorded impairment charges of $23.7 million, $20.3 million and $40.7 million, respectively, on its unproved properties.

Asset Retirement Obligations

QEP is obligated to fund the costs of disposing of long-lived assets upon their abandonment. The majority of QEP's asset retirement obligations (ARO) relate to the plugging of wells and the related abandonment of oil and gas properties. QEP's 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. Revisions to estimated ARO can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimate timing of abandonment. QEP's ARO liability at December 31, 2012 was $193.1 million.

Accounting for Derivative Contracts

The Company uses derivative contracts, typically fixed-price swaps and costless collars, to protect against a decline in the price it receives from its natural gas, oil and NGL production. Accounting rules for derivatives require marking these instruments to fair value at the balance sheet reporting date. The change in fair value is reported either in net income or AOCI depending on the structure of the derivative. Prior to 2012, the Company structured the majority of its energy derivative instruments as cash flow hedges as defined in ASC 815, *Derivatives and Hedging*. Changes in the fair value of cash flow hedges are recorded on the balance sheet and in AOCI until the underlying gas or oil is produced. When a derivative is terminated before its contract expires, the associated gain or loss is recognized in income over the life of the previously hedged production. Changes in the fair value of derivative contracts that do not qualify for hedge accountings are included as part of operating income in the Consolidated Statements of Operations.

Effective January 1, 2012, the Company elected to de-designate all of its natural gas, oil and NGL derivative contracts that had previously been designated as cash flow hedges at December 31, 2011, and elected to discontinue hedge accounting prospectively. Accordingly, changes in the fair value of commodity derivative contracts are reported in earnings as unrealized gains (losses). See Part II, Item 8, Note 1 - Summary of Significant Accounting Policies, of this Annual Report on Form 10-K for additional information.

Revenue Recognition

Revenues are recognized in the period that services are provided or products are delivered. QEP Energy uses the sales method of accounting whereby revenue is recognized for all gas, oil and NGL sold to purchasers. Revenues include estimates for the two most recent months using published commodity-price indexes and volumes supplied by field operators. A liability is recorded to the extent that QEP Energy has an imbalance in excess of its share of remaining reserves in an underlying property. QEP Marketing presents revenues on a gross revenue basis. 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 prices.

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. Because legal proceedings are inherently unpredictable and unfavorable resolutions could 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, and/or the ongoing discovery and development of information important to the matters. QEP regularly reviews contingencies to determine the adequacy of its accruals and related disclosures. The amount of ultimate loss may differ from these estimates.

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 Part II, Item 8, Note 9 - Commitments and Contingencies, of this Annual Report on form 10-K for additional information regarding current environmental claims.

Benefit Plan Obligations

QEP maintains closed, non-contributory 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 Income Statement.

Accounting for pension and other postretirement benefit obligations involves many assumptions, the most significant of which are the discount rate used to measure the present value of plan benefit obligations, the expected long-term rates of return on plan assets, the rate of future increases in compensation levels of participating employees and the future level of health care costs.

Share-Based Compensation
QEP uses the Black-Scholes-Merton mathematical model to estimate the fair value of stock options for accounting purposes. The use of this model requires significant judgment with respect to the risk-free interest rate, expected price volatility, expected dividend yield, and expected life.

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.

Purchase Price Allocations
QEP occasionally acquires assets and assumes liabilities in transactions accounted for as business combinations, such as the 2012 Acquisition in the Williston Basin. In connection with a purchase 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.

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 crude oil and natural 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 crude oil, NGL and natural gas 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, the discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors.

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 Part II, Item 8, Note 2 - Acquisition, of this Annual Report on Form 10-K for additional information regarding the 2012 Acquisition.

Recent Accounting Developments
See Recent Accounting Developments in Note 1 to the consolidated financial statements 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 risk exposures arise from changes in the market price for natural gas, oil and NGL, and to 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 Energy and QEP Marketing also have long-term contracts for pipeline capacity and are obligated to pay for transportation services with no guarantee that QEP will be able to fully utilize the contractual capacity of these transportation commitments. In addition, a write-down of the Company's oil and gas properties may be required if future oil and natural gas commodity prices experience a sustained, significant decline. Furthermore, the Company's credit facility and Term Loan have floating interest rates which expose QEP to interest rate risk. To manage the Company's exposure to these risks, QEP enters into commodity derivative contracts in the form of costless collars and fixed-price swaps to manage commodity price risk and periodically interest rate swaps to manage interest rate risk.

Commodity Price Risk Management

QEP's subsidiaries use commodity price derivative instruments in the normal course of business to reduce the risk of adverse commodity price movements. The Company's risk management policies provide for the use of derivative instruments to manage this risk. However, these same arrangements typically limit future gains from favorable price movements. The types of commodity derivative instruments utilized by the Company include fixed-price swaps and costless collars. The volume of commodity derivative instruments utilized by the Company may vary from year to year. The derivative instruments currently utilized by the Company do not have margin requirements or collateral provisions that would require payments prior to the scheduled cash settlement dates. The Company does not enter into derivative contracts for speculative or trading purposes. As of December 31, 2012, QEP held commodity price derivative contracts totaling 139.4 million MMBtu of natural gas, and 6.9 million barrels of oil. At December 31, 2011, the QEP derivative contracts consisted of 213.0 million MMBtu of natural gas, 2.0 million barrels of oil, and 53.9 million gallons of NGL.

The following table presents open 2013 derivative positions as of February 13, 2013:

QEP Energy Commodity Derivative Positions

Year	Type of Contract	Index	Total Volumes	Swaps Average price per unit
			(in millions)	
Natural gas sales			**(MMBtu)**	
2013	Swap	NYMEX	51.1	$ 3.79
2013	Swap	IFNPCR	65.7	$ 5.66
2014	Swap	NYMEX	18.3	$ 4.21
2014	Swap	IFNPCR	7.3	$ 4.00
Oil sales			**(Bbls)**	
2013	Swap	NYMEX WTI	5.7	98.35
2013	Swap	BRENTICE	0.3	$ 107.80
2014	Swap	NYMEX WTI	4.7	$ 92.99

QEP Marketing Commodity Derivative Positions

Year	Type of Contract	Index	Total Volumes	Average Swaps price per MMBtu
			(in millions)	
Natural gas sales			**(MMBtu)**	
2013	Swap	IFNPCR	4.0	$ 3.78
Natural gas purchases			**(MMBtu)**	
2013	Swap	IFNPCR	0.2	$ 2.88
2014	Swap	IFNPCR	0.1	$ 3.02

Changes in the fair value of derivative contracts from December 31, 2011, to December 31, 2012, are presented below:

	Commodity derivative contracts
	(in millions)
Net fair value of gas, oil and NGL derivative contracts outstanding at December 31, 2011	$ 395.9
Contracts settled	(380.0)
Change in gas and oil prices on futures markets	139.4
Contracts added	37.5
Net fair value of gas, oil and NGL derivative contracts outstanding at December 31, 2012	**$ 192.8**

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

	December 31, 2012
	(in millions)
Net fair value - asset (liability)	**$ 192.8**
Fair value if market prices of gas, oil and NGL and basis differentials decline by 10%	**304.7**
Fair value if market prices of gas, oil and NGL and basis differentials increase by 10%	**80.9**

Utilizing the actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these instruments by $111.9 million, while a 10% decrease in underlying commodity prices would increase the fair value of these instruments by $111.9 million as of December 31, 2012. 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 8 – Derivative Contracts, under Part II, Item 8 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 expose QEP to interest rate risk. At December 31, 2012, the Company had $690.0 million outstanding under its credit facility. If interest rates were to increase or decrease 10% during the year ended December 31, 2012, at our average level of borrowing for those same periods, our interest expense would increase or decrease by $0.8 million for the year ended December 31, 2012, or less than 1% of total interest expense. The remaining $2,221.8 million of the Company's debt is fixed rate senior notes that are not subject to interest rate movements.

The Company's Term Loan has a floating interest rate which exposes QEP to interest rate risk. At December 31, 2012, the Company had $300.0 million outstanding under the Term Loan. During the second quarter of 2012, QEP entered into interest rate swap contracts with an aggregate notional amount of $300.0 million, to minimize the interest rate volatility risk associated with its $300.0 million Term Loan. QEP pays a fixed interest rate and receives a floating interest rate indexed to the one-month LIBOR. At December 31, 2012, the fair value of the interest rate swaps was a derivative liability balance of $6.2 million. A 50 basis point decrease in the one-month LIBOR rate would cause the fair value of the interest rate swaps to decrease by $5.5 million while a 50 basis point increase in the one-month LIBOR rate would cause the fair value of the interest rate swaps to increase by $6.1 million. For additional information regarding the Company's debt instruments, see Note 8 – Debt, under Part II, Item 8 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 sheet and the related consolidated statement of operations, comprehensive income, equity, and cash flows present fairly, in all material respects, the financial position of QEP Resources, Inc. at December 31, 2012 and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule for the year ended December 31, 2012 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, 2012, based on criteria established in Internal Control - Integrated Framework 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, financial statement schedule and on the Company's internal control over financial reporting based on our integrated audit. 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 audit 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 financial statements, the Company discontinued hedge accounting effective January 1, 2012.

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 21, 2013

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholder of
QEP Resources, Inc.

We have audited the accompanying consolidated balance sheets of QEP Resources, Inc. as of December 31, 2011, and the related consolidated statements of operations, comprehensive income (loss), equity, and cash flows for each of the two years in the period ended December 31, 2011. Our audits also included the financial statement schedule listed in the Index at Item 8 for each of the two years in the period ended December 31, 2011. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of QEP Resources, Inc. at December 31, 2011, and the consolidated results of its operations and its cash flows for each of the two years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Ernst & Young LLP
Denver, Colorado
February 24, 2012

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2012	2011	2010
REVENUES	(in millions, except per share amounts)		
Natural gas sales	**$ 667.4**	$ 1,239.1	$ 1,205.3
Oil sales	**532.6**	324.2	198.1
NGL sales	**322.1**	309.8	142.6
Gathering, processing and other	**181.6**	200.8	156.6
Purchased gas, oil and NGL sales	**646.1**	1,085.3	598.0
Total Revenues	**2,349.8**	3,159.2	2,300.6
OPERATING EXPENSES			
Purchased gas, oil and NGL expense	**655.6**	1,077.1	589.3
Lease operating expense	**172.3**	145.2	125.0
Natural gas, oil and NGL transport & other handling costs	**148.9**	102.2	54.2
Gathering, processing and other	**88.0**	107.3	83.2
General and administrative	**266.6**	123.2	107.2
Separation costs	**—**	—	13.5
Production and property taxes	**103.4**	105.4	82.5
Depreciation, depletion and amortization	**904.9**	765.4	643.4
Exploration expenses	**11.2**	10.5	23.0
Abandonment and impairment	**133.4**	218.4	46.1
Total Operating Expenses	**2,484.3**	2,654.7	1,767.4
Net gain from asset sales	**1.2**	1.4	12.1
OPERATING (LOSS) INCOME	**(133.3)**	505.9	545.3
Realized and unrealized gains on derivative contracts (See Note 6)	**441.9**	—	—
Interest and other income	**6.6**	4.1	2.3
Income from unconsolidated affiliates	**6.8**	5.5	3.0
Loss from early extinguishment of debt	**(0.6)**	(0.7)	(13.3)
Interest expense	**(122.9)**	(90.0)	(84.4)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	**198.5**	424.8	452.9
Income taxes	**(66.5)**	(154.4)	(167.0)
INCOME FROM CONTINUING OPERATIONS	**132.0**	270.4	285.9
Discontinued operations, net of income tax	**—**	—	43.2
NET INCOME	**132.0**	270.4	329.1
Net income attributable to noncontrolling interest	**(3.7)**	(3.2)	(2.9)
NET INCOME ATTRIBUTABLE TO QEP	**$ 128.3**	$ 267.2	$ 326.2
Earnings Per Common Share Attributable to QEP			
Basic from continuing operations	**$ 0.72**	$ 1.51	$ 1.61
Basic from discontinued operations	**—**	—	0.25
Basic total	**$ 0.72**	$ 1.51	$ 1.86
Diluted from continuing operations	**$ 0.72**	$ 1.50	$ 1.60
Diluted from discontinued operations	**—**	—	0.24
Diluted total	**$ 0.72**	$ 1.50	$ 1.84
Weighted-average common shares outstanding			
Used in basic calculation	**177.8**	176.5	175.3
Used in diluted calculation	**178.7**	178.4	177.3

See notes accompanying the consolidated financial statements.

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

	Year Ended December 31,		
	2012	2011	2010
	(in millions)		
Net income	**$ 132.0**	$ 270.4	$ 329.1
Other comprehensive (loss) income, net of tax:			
Effect of derivative financial instruments [1]	**(171.1)**	24.8	136.7
Pension and other postretirement plans adjustments:			
Current year net actuarial gain (loss) [2]	**(10.0)**	(14.7)	2.6
Amortization of net actuarial loss [3]	**1.1**	—	—
Net prior service cost incurred [4]	**—**	—	(33.8)
Amortization of net prior service cost [5]	**3.5**	3.5	1.7
Net curtailment cost incurred [6]	**1.4**	—	—
Total pension and other postretirement plans adjustments	**(4.0)**	(11.2)	(29.5)
Other comprehensive (loss) income	**(175.1)**	13.6	107.2
Comprehensive (loss) income	**(43.1)**	284.0	436.3
Comprehensive income attributable to noncontrolling interests	**(3.7)**	(3.2)	(2.9)
Comprehensive (loss) income attributable to QEP	**$ (46.8)**	$ 280.8	$ 433.4

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(1) Presented net of income tax benefit of $101.3 million during the year ended December 31, 2012, and net of income tax expense of $14.7 million and $81.0 million during the years ended December 31, 2011 and 2010, respectively.
(2) Presented net of income tax benefit of $6.3 million and $9.2 million during the years ended December 31, 2012 and 2011, respectively, and net of income tax expense of $1.6 million for the year ended December 31, 2010.
(3) Presented net of income tax expense of $0.9 million during the year ended December 31, 2012.
(4) Presented net of income tax benefit of $20.9 million during the year ended December 31, 2010.
(5) Presented net of income tax expense of $2.2 million, $2.1 million and $1.0 million during the years ended December 31, 2012, 2011 and 2010, respectively.
(6) Presented net of income tax expense of $0.8 million during the year ended December 31, 2012.

See notes accompanying the consolidated financial statements.

QEP RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2012	December 31, 2011
ASSETS	(in millions)	
Current Assets		
Cash and cash equivalents	**$ —**	$ —
Accounts receivable, net	**387.5**	397.4
Fair value of derivative contracts	**188.7**	273.7
Gas, oil and NGL inventories, at lower of average cost or market	**13.1**	16.2
Prepaid expenses and other	**60.4**	43.7
Total Current Assets	**649.7**	731.0
Property, Plant and Equipment (successful efforts method for gas and oil properties)		
Proved properties	**10,234.3**	8,172.4
Unproved properties, net	**937.9**	326.8
Midstream field services	**1,634.9**	1,463.6
Marketing and other	**64.6**	49.8
Material and supplies	**61.9**	87.6
Total Property, Plant and Equipment	**12,933.6**	10,100.2
Less Accumulated Depreciation, Depletion and Amortization		
Exploration and production	**4,258.1**	3,339.2
Midstream field services	**357.9**	297.5
Marketing and other	**18.1**	14.6
Total Accumulated Depreciation, Depletion and Amortization	**4,634.1**	3,651.3
Net Property, Plant and Equipment	**8,299.5**	6,448.9
Investment in unconsolidated affiliates	**41.2**	42.2
Goodwill	**59.5**	59.5
Fair value of derivative contracts	**4.1**	123.5
Other noncurrent assets	**54.5**	37.6
TOTAL ASSETS	**$ 9,108.5**	$ 7,442.7
LIABILITIES AND EQUITY		
Current Liabilities		
Checks outstanding in excess of cash balances	**$ 39.7**	$ 29.4
Accounts payable and accrued expenses	**635.9**	457.3
Production and property taxes	**41.8**	40.0
Interest payable	**36.9**	24.4
Fair value of derivative contracts	**2.6**	1.3
Deferred income taxes	**5.0**	85.4
Total Current Liabilities	**761.9**	637.8
Long-term debt	**3,206.9**	1,679.4
Deferred income taxes	**1,493.5**	1,484.7
Asset retirement obligations	**191.4**	163.9
Fair value of derivative contracts	**3.6**	—
Other long-term liabilities	**137.5**	124.8
Commitments and contingencies (see Note 9)		
EQUITY		
Common stock - par value $0.01 per share; 500.0 million shares authorized; 178.5 million and 177.2 million shares issued, respectively	**1.8**	1.8
Treasury stock - 0.1 million and 0.4 million shares, respectively	**(3.7)**	(13.1)
Additional paid-in capital	**462.1**	431.4
Retained earnings	**2,773.0**	2,673.5
Accumulated other comprehensive income	**32.8**	207.9
Total Common Shareholders' Equity	**3,266.0**	3,301.5
Noncontrolling interest	**47.7**	50.6
Total Equity	**3,313.7**	3,352.1
TOTAL LIABILITIES AND EQUITY	**$ 9,108.5**	$ 7,442.7

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, 2009	174.6	$ 1.7	—	$ —	$ 126.8	$ 2,538.2	$ 87.1	$ 54.9	$ 2,808.7
Questar common stock issued, net of repurchases	0.4	—	—	—	—	—	—	—	—
2010 net income	—	—	—	—	—	326.2	—	2.9	329.1
Dividends paid	—	—	—	—	—	(15.9)	—	—	(15.9)
Share-based compensation	0.9	0.1	(0.1)	(3.9)	23.3	—	—	—	19.5
Equity from Questar	—	—	—	—	250.0	—	—	—	250.0
Transfer Wexpro to Questar	—	—	—	—	(2.0)	(428.5)	—	—	(430.5)
Distribution of noncontrolling interest	—	—	—	—	—	—	—	(5.0)	(5.0)
Change in unrealized fair value of derivatives, net of tax	—	—	—	—	—	—	136.7	—	136.7
Change in pension and postretirement liability, net of tax	—	—	—	—	—	—	(29.5)	—	(29.5)
Balance at December 31. 2010	175.9	1.8	(0.1)	(3.9)	398.1	2,420.0	194.3	52.8	3,063.1
2011 net income	—	—	—	—	—	267.2	—	3.2	270.4
Dividends paid	—	—	—	—	—	(14.1)	—	—	(14.1)
Share-based compensation	1.3	—	(0.3)	(9.2)	33.3	—	—	—	24.1
Distribution from Questar and other	—	—	—	—	—	0.4	—	—	0.4
Distribution of noncontrolling interest	—	—	—	—	—	—	—	(5.4)	(5.4)
Change in unrealized fair value of derivatives, net of tax	—	—	—	—	—	—	24.8	—	24.8
Change in pension and postretirement liability, net of tax	—	—	—	—	—	—	(11.2)	—	(11.2)
Balance at December 31. 2011	177.2	1.8	(0.4)	(13.1)	431.4	2,673.5	207.9	50.6	3,352.1
2012 net income	**—**	**—**	**—**	**—**	**—**	**128.3**	**—**	**3.7**	**132.0**
Dividends paid	**—**	**—**	**—**	**—**	**—**	**(14.2)**	**—**	**—**	**(14.2)**
Share-based compensation	**1.3**	**—**	**0.2**	**7.1**	**30.7**	**(14.6)**	**—**	**—**	**23.2**
Distribution to QEP Education Foundation	**—**	**—**	**0.1**	**2.3**	**—**	**—**	**—**	**—**	**2.3**
Distribution of noncontrolling interest	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(6.6)**	**(6.6)**
Reclassification of previously deferred derivative gains in OCI, net of tax	**—**	**—**	**—**	**—**	**—**	**—**	**(171.1)**	**—**	**(171.1)**
Change in pension and postretirement liability, net of tax	**—**	**—**	**—**	**—**	**—**	**—**	**(4.0)**	**—**	**(4.0)**
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**

See notes accompanying the consolidated financial statements.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2012	2011	2010
OPERATING ACTIVITIES	(in millions)		
Net income	**$ 132.0**	$ 270.4	$ 329.1
Discontinued operations, net of income tax	—	—	(43.2)
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**904.9**	765.4	643.4
Deferred income taxes	**32.1**	156.8	188.2
Abandonment and impairment	**133.4**	218.4	46.1
Share-based compensation	**25.6**	22.0	16.1
Amortization of debt issuance costs and discounts	**5.3**	4.1	2.4
Net gain from asset sales	**(1.2)**	(1.4)	(12.1)
Income from unconsolidated affiliates	**(6.8)**	(5.5)	(3.0)
Distributions from unconsolidated affiliates and dry exploratory well expense	**7.9**	8.1	11.8
Non-cash loss on early extinguishment of debt	**—**	0.7	13.3
Unrealized gain on derivative contracts	**(63.2)**	(117.7)	(121.7)
Changes in operating assets and liabilities			
Accounts receivable	**9.6**	(144.6)	(32.6)
Inventories	**28.7**	(22.0)	10.1
Prepaid expenses	**(16.8)**	1.6	(16.2)
Accounts payable and accrued expenses	**101.3**	127.8	4.2
Federal income taxes	**3.5**	17.0	(30.9)
Other	**(0.3)**	(8.5)	(7.5)
Net Cash Provided by Operating Activities of Continuing Operations	**1,296.0**	1,292.6	997.5
INVESTING ACTIVITIES			
Property acquisitions	**(1,401.0)**	(48.0)	(109.3)
Property, plant and equipment, including dry hole exploratory well expense	**(1,398.7)**	(1,383.1)	(1,359.7)
Proceeds from disposition of assets	**5.2**	8.2	25.6
Change in notes receivable	—	—	52.9
Net Cash Used in Investing Activities of Continuing Operations	**(2,794.5)**	(1,422.9)	(1,390.5)
FINANCING ACTIVITIES			
Checks outstanding in excess of cash balances	**10.3**	9.9	19.5
Long-term debt issued	**1,450.0**	—	1,034.4
Long-term debt issuance costs paid	**(17.8)**	(10.6)	(16.6)
Long-term debt repaid	**(6.7)**	(58.5)	(91.5)
Repayments of notes payable	**—**	—	(39.3)
Long-term debt extinguishment costs	**—**	—	(4.9)
Proceeds from credit facility	**1,234.5**	591.5	—
Repayments of credit facility	**(1,151.0)**	(385.0)	(761.5)
Other capital contributions	**(2.2)**	0.7	2.8
Equity contribution	**—**	—	250.0
Dividends paid	**(14.2)**	(14.1)	(7.0)
Excess tax benefit on share-based compensation	**2.2**	1.6	—
Distribution from Questar	—	0.2	(7.2)
Distribution to noncontrolling interest	**(6.6)**	(5.4)	(5.0)
Net Cash Provided by Financing Activities of Continuing Operations	**1,498.5**	130.3	373.7
CASH USED IN CONTINUING OPERATIONS	**—**	—	(19.3)
Cash provided by operating activities of discontinued operations	**—**	—	68.6
Cash used in investing activities of discontinued operations	**—**	—	(39.9)
Cash used in financing activities of discontinued operations	**—**	—	(26.9)
Effect of change in cash and cash equivalents of discontinued operations	**—**	—	1.8
Change in cash and cash equivalents	**—**	—	(19.3)
Beginning cash and cash equivalents	**—**	—	19.3
Ending cash and cash equivalents	**$ —**	$ —	$ —

See 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 three major lines of business: natural gas and crude oil exploration and production; midstream field services; and energy marketing. These businesses are conducted through the Company's three principal subsidiaries:

- QEP Energy Company (QEP Energy) acquires, explores for, develops, and produces natural gas, oil, and natural gas liquids (NGL);

- QEP Field Services Company (QEP Field Services) provides midstream field services, including natural gas gathering, processing, compression, and treating services, for affiliates and third parties; and

- QEP Marketing Company (QEP Marketing) markets affiliate and third-party natural gas and oil, and owns and operates an underground gas-storage reservoir.

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

Shares of QEP Resources' 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 U.S. Generally Accepted Accounting Principles (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.

Effective May 18, 2010, Questar Market Resources, Inc., (Market Resources) then a wholly owned subsidiary of Questar Corporation (Questar), merged with and into a newly-formed, wholly owned subsidiary, QEP, a Delaware corporation in order to reincorporate in the State of Delaware (Reincorporation Merger). The Reincorporation Merger was affected pursuant to an Agreement and Plan of Merger entered into between Market Resources and QEP. The Reincorporation Merger was approved by the boards of directors of Market Resources and QEP and submitted to a vote of, and approved by, the Board of Directors of Questar, as sole shareholder of Market Resources, and by Market Resources, as sole shareholder of QEP on May 18, 2010.

On June 30, 2010, Questar distributed all of the shares of common stock of QEP held by Questar to Questar shareholders in a tax-free, pro rata dividend (the Spin-off). Each Questar shareholder received one share of QEP common stock for each one share of Questar common stock held (including fractional shares) at the close of business on the record date. In connection therewith, QEP distributed Wexpro Company (Wexpro), a wholly owned subsidiary of QEP at the time, to Questar. In addition, Questar contributed $250.0 million of equity to QEP prior to the Spin-off.

The financial information presented in this Annual Report on Form 10-K presents QEP's financial results as an independent company separate from Questar and reflects Wexpro's financial condition and operating results as discontinued operations for all periods presented. A summary of discontinued operations can be found in Note 13 to the consolidated financial statements.

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

Investment in Unconsolidated Affiliates

QEP uses the equity method to account for investment in unconsolidated affiliates where it does not have control, but has significant influence. The investment in unconsolidated affiliates on the Company's consolidated balance sheets equals the Company's proportionate share of equity reported by the unconsolidated affiliates. Investment is assessed for possible impairment when events indicate that the fair value of the investment may be below the Company's carrying value. When such a condition is deemed to be other than temporary, the carrying value of the investment is written down to its fair value, and the amount of the write-down is included in the determination of net income.

The principal unconsolidated affiliates and QEP's ownership percentage as of December 31, 2012 and 2011, were Uintah Basin Field Services, LLC, (38%) and and Three Rivers Gathering, LLC, (50%), both limited liability companies engaged in gathering and compressing natural gas.

Reclassifications

In 2011, "Gathering, processing and other" revenues included "NGL" which were reclassified to conform with the current period presentation on the Consolidated Statement of Operations. The NGL reclassification is all within "Revenues" and has no effect on income from continuing operations, net income or earnings per share. Additionally, QEP reclassified "Materials and supplies" as of December 31, 2011, from current to long-term on the Consolidated Balance Sheet for consistency with current period presentation.

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 natural gas, oil and NGL reserves which are used in the calculation of depreciation, depletion and amortization rates of its gas and oil 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 gas and oil reserves. Other items subject to estimates and assumptions include the carrying amount of property, plant and equipment and goodwill, 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.

Revenue Recognition

QEP subsidiaries recognize revenues in the period that services are provided or products are delivered. Revenues associated with the sale of natural gas and oil are accounted for using the sales method, whereby revenue is recognized as gas and oil is sold to purchasers. A liability is recorded to the extent that the Company has sold volumes in excess of its share of remaining gas and oil reserves in an underlying property. QEP's imbalance obligations at December 31, 2012 and 2011, were $13.2 million and $13.3 million, respectively.

QEP Marketing reports revenues on a gross basis because, in the judgment of management, the nature and circumstances of its marketing transactions are consistent with guidance for gross revenue reporting. QEP Marketing markets affiliate and third-party natural 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. QEP Marketing has not engaged in buy/sell arrangements, as described in ASC 845-10-25-4, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*.

Cash and Cash Equivalents

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

Supplemental cash flow information is shown in the below table:

	Year Ended December 31,		
	2012	2011	2010
Supplemental Disclosures:	(in millions)		
Cash paid for interest, net of capitalized interest	**$ 105.1**	$ 90.5	$ 80.2
Cash paid (received) for income taxes	**30.0**	(28.5)	14.0
Non-cash investing activities			
Change in capital expenditure accrual balance	**$ 88.5**	$ 14.7	$ 16.9

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. Bad-debt expense associated with accounts receivable for the years ended December 31, 2012 and 2011 was $1.4 million and $0.2 million, respectively, and a credit of $0.3 million in 2010. The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectability. The allowance for bad-debt expenses was $2.8 million at December 31, 2012, and $1.7 million at December 31, 2011.

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 with the exception of compressor maintenance costs, which are capitalized and depreciated. Significant accounting policies for our property, plant and equipment are as follows:

Gas and oil properties
QEP Energy uses the successful efforts method to account for gas and oil properties. The costs of acquiring leaseholds, drilling development wells, drilling successful exploratory wells, purchasing related support equipment and facilities are capitalized. Geological and geophysical studies and other exploratory activities are expensed as incurred. Costs of production and general- corporate activities are expensed in the period 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 as 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 gas and oil reserves. If the Company concludes that the well is noncommercial, well costs are immediately charged to exploration expense. Exploratory-well costs 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
Capitalized proved leasehold costs are depleted on a field-by-field basis using the unit-of-production method and the estimated proved gas and oil reserves. 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. Capitalized costs of exploratory wells that have found proved gas and oil reserves and capitalized development costs are depreciated using the unit-of-production method based on estimated proved developed reserves for a successful effort field pool. The Company capitalizes an estimate of the fair value of future abandonment costs.

Depreciation, depletion and amortization for the remaining Company properties is based upon rates that will systematically charge the costs of assets against income over the estimated useful lives of those assets using either a straight-line or unit-of-production method. Investment in gas gathering and processing fixed assets is charged to expense using either the straight-line or unit-of-production method depending upon the facility. 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 gas and oil properties are evaluated on a field-by-field basis for potential impairment. 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 gas and oil reserves caused by mechanical problems, faster-than-expected decline of reserves, lease-ownership issues, declines in natural gas, NGL and crude oil prices and changes in the utilization of midstream gathering and processing assets. 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, 2012, QEP recorded abandonment and impairment charges of $133.4 million on its oil and gas properties. Of the $133.4 million abandonment and impairment charges during the year ended December 31, 2012, $107.6 million related to price-related impairment charges on proved properties and $23.7 million related to impairment on unproved properties. The impairment charges were related to the reduced value of certain fields resulting from lower natural gas, crude oil and NGL prices and impairments of unproven leasehold acquisition costs. Of the $133.4 million abandonment and impairment charges during the year ended December 31, 2012, $104.8 million was related to oil and gas properties in the Southern Region and $28.6 million was related to oil and gas properties in the Northern Region. During the year ended December 31, 2011, QEP recorded abandonment and impairment charges of $218.4 million, $173.1 million were related to properties in the Northern Region with the remaining $45.3 million related to properties in the Southern Region. Of the $218.4 million abandonment and impairment charges during the year ended December 31, 2011, $195.5 million related to the impairment charges on proved properties and $20.3 million related to impairment on unproved properties. During the year ended December 31, 2010, QEP recorded abandonment and impairment charges of $46.1 million, of which $0.7 million related to proved property impairments and $40.7 million related to impairment on unproved properties.

Asset Retirement Obligations
Asset retirement obligations (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.

Capitalized Interest
The Company capitalizes interest costs during the construction phase of large capital projects that meet certain criteria. Capitalized interest was $3.4 million, $3.0 million and $3.1 million during the years ended December 31, 2012, 2011 and 2010, respectively.

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 9 - 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.

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. As of December 31, 2012 and 2011, goodwill was $59.5 million and related to the Uinta Basin reporting unit within QEP Energy. Goodwill is tested for impairment at a minimum of once a year or when a triggering event occurs using the income approach. Under the income approach, the fair value is estimated based on the value of expected future cash flows. Key assumptions used in the cash flow model consider estimated quantities of crude oil, NGL and natural gas reserves, including both proved reserves and risk-adjusted unproved reserves; estimates of market prices considering forward commodity price curves as of the measurement date; and estimates of operating, administrative and capital costs adjusted for inflation. The undiscounted net cash flows of the reporting unit to which the goodwill relates are evaluated. Impairment is indicated if undiscounted cash flows are less than the carrying value of the assets. The amount of the impairment is measured using a discounted, cash flow model considering future revenues, operating costs, a risk-adjusted discount rate and other factors. There have been no goodwill impairments.

Derivative Instruments

Effective January 1, 2012, the Company elected to de-designate all of its natural gas, oil and NGL derivative contracts that had previously been designated as cash flow hedges and has elected to discontinue hedge accounting prospectively. Accordingly, all realized and unrealized gains and losses are recognized in earnings immediately as derivative contracts are settled and marked-to-market. For the year ended December 31, 2012, unrealized gains of $63.2 million were included in income that, prior to January 1, 2012, would have been deferred in Accumulated Other Comprehensive Income (AOCI) under hedge accounting (Refer to Note 6 – Derivative Contracts, for additional information). At December 31, 2011, AOCI consisted of $395.9 million ($248.6 million after tax) of unrealized gains, representing the mark-to-market value of the Company's cash flow hedges as of the balance sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting, such mark-to-market values at December 31, 2011, were frozen in AOCI as of the de-designation date and are being reclassified into earnings as the original hedged transactions occur and effect earnings. QEP expects to reclassify into earnings from AOCI the remaining frozen value, $123.5 million ($77.6 million after tax), related to de-designated natural gas, oil and NGL hedges during 2013.

All of QEP's derivative contracts are net settled in cash without delivery of product. These contracts also have a nominal quantity and exchange an index price for a fixed price, and are net settled with the brokers as the price bulletins become available. These derivative contracts are recorded in revenues or cost of sales in the month of settlement. Basis-only swaps are used to manage the risk of widening basis differentials. These contracts are marked to market monthly with any change in the valuation recognized in the determination of income.

Credit Risk

The Northern and Southern Regions constitute the Company's primary market areas. Exposure to credit risk may be affected by the concentration of customers in these 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 hedging arrangements 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 37%, 32%, and 27% in aggregate, of QEP revenues during the years ended December 31, 2012, 2011 and 2010, respectively. During the year ended December 31, 2012, Chevron U.S.A. Inc. and Enterprise Products Operating, L.P. accounted for 13% and 10%, respectively, of the Company's total revenues. Management believes that the loss of either customer, 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 years ended December 31, 2011 and 2010, each of the five largest customers sales were below 10% of QEP's total revenues.

Income Taxes

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. The Company records interest earned on income tax refunds in interest and other income and records penalties and interest charged on tax deficiencies in interest expense.

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. There were no unrecognized tax benefits at the beginning or at the end of the twelve-month periods ended December 31, 2012, 2011 and 2010. The federal income tax returns for 2011 and 2010 are currently under examination by the Internal Revenue Service. Income tax returns for 2012 have not yet been filed. Most state tax returns for 2009 and subsequent years remain subject to examination.

Treasury Stock

We record treasury stock purchases at costs, which includes incremental direct transaction costs. Amounts are recorded as a reduction in shareholders' equity in the consolidated balance sheets. Acquired treasury stock is used for stock grants to employees; refer to Note 10 - Share-Based Compensation for additional information.

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 nonforfeitable 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 nonforfeitable 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. A reconciliation of the components of basic and diluted shares used in the EPS calculation follows:

	December 31,		
	2012	2011	2010
	(in millions)		
Weighted-average basic common shares outstanding	**177.8**	176.5	175.3
Potential number of shares issuable under the Long-Term Stock Incentive Plan	**0.9**	1.9	2.0
Average diluted common shares outstanding	**178.7**	178.4	177.3

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 terms 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. At the time of the Spin-off, all outstanding options and restricted stock were bifurcated. The Company also awards performance share units which are paid out in cash that is dependent 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. For a summary of LTSIP transactions see Note 10—Share-Based Compensation.

Pension Plans, Other Postretirement Benefits and Defined-Contribution Plans

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), the rate of future compensation increases and the health care cost trend rate. Other assumptions involve demographic factors such as retirement, mortality and turnover. QEP evaluates and updates its actuarial assumptions at least annually.

Comprehensive Income

Comprehensive income is the sum of net income attributable to QEP 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. One component of other comprehensive income is changes in the market value of commodity-based derivative instruments that qualified for hedge accounting. Income or loss associated with commodity-based derivative instruments that qualified for hedge accounting is realized when the natural gas, oil or NGL underlying the derivative instrument is sold. Comprehensive income also includes changes in the under-funded portion of the defined benefit pension plans and other postretirement benefits plans and changes in deferred income taxes on such amounts. These transactions are not 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, QEP Field Services, and QEP Marketing and other corporate activities not attributable to a line of business.

Recent Accounting Developments

In December of 2011, the FASB issued ASU 2011-11, *Disclosures about Offsetting Assets and Liabilities*, which enhances disclosure requirements regarding an entity's financial instruments and derivative instruments that are offset or subject to a master netting arrangement. This information about offsetting and related netting arrangements will enable users of financial statements to understand the effect of those arrangements on the entity's financial position, including the effect of rights of setoff. The amendments are required for annual reporting periods beginning after January 1, 2013, and interim periods within those annual periods. QEP is evaluating the impact of this ASU on its disclosure requirements.

In July of 2012, the FASB issued ASU 2012-02, *Intangibles - Goodwill and Other: Testing Indefinite-Lived Intangible Assets for Impairment*, which revises the way an entity can test indefinite-lived intangible assets for impairment by allowing an entity to first assess qualitative factors to determine whether the existence of events and circumstances indicates that it is more likely than not that the indefinite-lived intangible asset is impaired. If there is no indication of impairment from the qualitative impairment test, the entity is not required to complete a quantitative impairment test of determining and comparing the fair value with the carrying amount of the indefinite-lived asset. Under the guidance in this ASU, an entity also has the option to bypass the qualitative assessment in any period and proceed directly in performing the quantitative impairment test and can resume performing the qualitative assessment in any subsequent period. The amendments are effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012. The adoption of this standard will allow the Company to more efficiently complete the annual goodwill impairment test but will not have a significant impact on the Company's consolidated financial statements.

Note 2 - Acquisition

On September 27, 2012, QEP Energy completed an acquisition of oil and gas properties in the Williston Basin for an aggregate purchase price of approximately $1.4 billion, subject to post-closing adjustments (the 2012 Acquisition). The properties are located in Williams and McKenzie counties of North Dakota, approximately 12 miles west of QEP's existing core acreage in the Williston Basin.

The 2012 Acquisition meets the definition of a business combination under ASC 805, *Business Combinations*, as it included proved properties. QEP allocated the cost of the 2012 Acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Revenues of $63.7 million and net income of $14.9 million generated from the acquired properties for the fourth quarter of 2012 and have been included in QEP's Consolidated Statements of Operations for the year ended December 31, 2012. During the year ended December 31, 2012, QEP Energy's acquisition-related costs of $1.1 million are included in "General and administrative" on the Consolidated Statements of Operations.

QEP Energy recorded the 2012 Acquisition on its Consolidated Balance Sheets; however, the final purchase price is subject to revision based on the settlement of post-closing adjustments. The following table presents a summary of the preliminary purchase accounting entries:

	As of December 31, 2012	
Consideration given:	(in millions)	
Cash consideration	**$**	**1,388.7**
Amounts recognized for preliminary fair value of assets acquired and liabilities assumed:		
Proved properties	**$**	**713.8**
Unproved properties		**679.4**
Asset retirement obligations		**(0.9)**
Liabilities assumed		**(4.4)**
Other assets acquired		**0.8**
Total fair value	**$**	**1,388.7**

The following unaudited, pro forma results of operations are provided for the years ended December 31, 2012 and 2011, as though the 2012 Acquisition had been completed as of the beginning of January 1, 2011. 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 properties for the periods presented or that may be achieved by the 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, 2012 and 2011, on the acquired properties historical results of operations and on estimates of the effect of the transaction on the combined results. The pro forma results of operations have been prepared by adjusting the historical results of QEP to include the historical results of the acquired properties based on information provided by the seller and the impact of the preliminary purchase price allocation. The pro forma results of operations do not include any cost savings or other synergies that may result from the 2012 Acquisition or any estimated costs that have been or will be incurred by the Company to integrate the properties.

	Year ended December 31,							
	2012				2011			
	Actual		Pro forma		Actual		Pro forma	
	(in millions, except per share data)							
Revenues	**$**	**2,349.8**	**$**	**2,485.3**	$	3,159.2	$	3,236.7
Net income attributable to QEP		**128.3**		**143.0**		267.2		259.8
Earnings per common share attributable to QEP								
Basic	**$**	**0.72**	**$**	**0.80**	$	1.51	$	1.47
Diluted		**0.72**		**0.80**		1.50		1.46

Note 3 - Capitalized Exploratory Well Costs

Net changes in capitalized exploratory well costs are presented in the table below and exclude amounts that were capitalized and subsequently expensed in the period. The balance at December 31, 2012, 2011 and 2010, represents the amount of capitalized exploratory well costs that are pending the determination of proved reserves.

	2012	2011	2010
		(in millions)	
Balance at January 1,	$ 5.0	$ 13.6	$ 51.7
Additions to capitalized exploratory well costs pending the determination of proved reserves	12.7	—	12.2
Reclassifications to proved properties after the determination of proved reserves	(15.6)	(8.3)	(50.3)
Capitalized exploratory well costs charged to expense	—	(0.3)	—
Balance at December 31,	$ 2.1	$ 5.0	$ 13.6

Note 4 – Asset Retirement Obligations

QEP records asset retirement obligations (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 gas and oil wells, production facilities 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 liability occur due to changes in estimated abandonment costs and well economic lives. The ARO liability is adjusted to present value each period through an accretion calculation using a credit-adjusted risk-free interest rate. Of the $193.1 million ARO liability,$1.7 million was included as a liability in "Accounts payable and accrued expenses" on the Consolidated Balance Sheet.

The following is a reconciliation of the changes in the asset retirement obligation for the periods specified below:

	Asset Retirement Obligations	
	2012	2011
	(in millions)	
ARO liability at January 1,	$ 163.9	$ 148.3
Accretion	10.5	9.7
Liabilities incurred	8.5	7.9
Revisions	11.1	—
Liabilities settled	(0.9)	(2.0)
ARO liability at December 31,	$ 193.1	$ 163.9

Note 5 – Fair Value Measurements

QEP measures and discloses fair values in accordance with the provisions of ASC 820, *Fair Value Measurements*. This guidance defines fair value in applying GAAP, establishes a framework for measuring fair value and expands disclosures about fair-value measurements, but does not change existing guidance as to whether or not an instrument is carried at fair value. 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 6 - Derivative Contracts) is based on market prices posted on the NYMEX 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.

However, 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.

In addition, QEP has interest rate swaps that it has determined are Level 2. The fair values of the interest rate swaps are determined using the market standard methodology of discounting the future expected cash flows that would occur under the contractual terms of the swap. The variable interest rates used in the calculation of projected cash flows are based on an expectation of future interest rates derived from observable market interest rate curves. QEP incorporates credit valuation adjustments to reflect both its nonperformance risk and the respective counterparty's nonperformance risk in the fair value measurements. While the credit valuation adjustments are not observable inputs, they are not significant to the overall valuation and the other inputs used to value the interest rate swaps are observable Level 2 inputs.

The fair value of financial assets and liabilities at December 31, 2012 and 2011, is shown in the tables below:

	Fair Value Measurements **December 31, 2012**				
	Level 1	Level 2	Level 3	Netting Adjustments	Total
	(in millions)				
Financial Assets					
Commodity derivative instruments - short-term	$ —	$ **189.7**	$ —	$ **(1.0)**	$ **188.7**
Commodity derivative instruments - long-term	—	**4.2**	—	**(0.1)**	$ **4.1**
Total financial assets	$ —	$ **193.9**	$ —	$ **(1.1)**	$ **192.8**
Financial Liabilities					
Commodity derivative instruments - short-term	$ —	$ **1.0**	$ —	$ **(1.0)**	$ —
Interest rate swaps - short-term	—	**2.6**	—	—	$ **2.6**
Commodity derivative instruments - long-term	—	**0.1**	—	**(0.1)**	$ —
Interest rate swaps - long-term	—	**3.6**	—	—	$ **3.6**
Total financial liabilities	$ —	$ **7.3**	$ —	$ **(1.1)**	$ **6.2**

	Level 1		Level 2		Level 3		Netting Adjustments		Total
	Fair Value Measurements December 31, 2011								
	(in millions)								
Financial Assets									
Commodity derivative instruments - short-term	$	—	$	284.1	$	—	$	(10.4)	$ 273.7
Commodity derivative instruments - long-term		—		123.5		—		—	$ 123.5
Total financial assets	$	—	$	407.6	$	—	$	(10.4)	$ 397.2
Financial Liabilities									
Commodity derivative instruments - short-term	$	—	$	11.7	$	—	$	(10.4)	$ 1.3
Commodity derivative instruments - long-term		—		—		—		—	$ —
Total financial liabilities	$	—	$	11.7	$	—	$	(10.4)	$ 1.3

Fair values related to the Company's crude oil costless collars were transferred from Level 3 to Level 2 in the second quarter of 2012, due to the enhancements to the Company's internal valuation process, including the use of observable inputs to assess the fair value. There were no other significant transfers in or out of Levels 1, 2 or 3 for the periods presented herein.

The change in the fair value of Level 3 commodity derivative instruments assets and liabilities for the years ended December 31, 2012 and 2011, are shown below:

	Change in Level 3 Fair Value Measurements	
	2012	2011
	(in millions)	
Balance at January 1,	**$ —**	$ 36.3
Realized gains and losses	**0.6**	25.3
Unrealized gains and losses	**3.8**	(36.3)
Settlements	**(0.6)**	(25.3)
Transfers out of Level 3	**(3.8)**	—
Balance at December 31,	**$ —**	$ —

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, 2012		December 31, 2011	
	(in millions)			
Financial liabilities				
Checks outstanding in excess of cash balances	**$ 39.7**	**$ 39.7**	$ 29.4	$ 29.4
Long-term debt	**$ 3,206.9**	**$ 3,420.7**	$ 1,679.4	$ 1,754.9

The carrying amount of checks outstanding in excess of cash balances approximates 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 quarter. 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 asset retirement obligations 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 are used in the calculation of asset retirement obligations include plugging costs and reserve lives. A reconciliation of the Company's asset retirement obligations is presented in Note 4 – Asset Retirement Obligations.

Nonrecurring Fair Value Measurements

The provisions of the fair value measurement standard are also applied to the Company's nonrecurring, non-financial measurements. The Company utilizes fair value on a non-recurring basis to review its proved oil and gas properties and goodwill 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, 2012 and 2011, 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, 2012 and 2011, the Company recorded $107.6 million and $195.5 million, respectively, of impairments related to some of its proved properties. The proved properties were written down to their estimated fair values of $71.9 million and $157.2 million at the time of the impairments during 2012 and 2011, 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 estimates 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 crude oil, natural gas 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. Due to the unobservable characteristics of the inputs, the fair value of the properties are considered Level 3 within the fair value hierarchy. Refer to Note 2 - Acquisition, for additional information on the fair value of acquired properties.

Note 6 – Derivative Contracts

QEP has established policies and procedures for managing commodity price volatility through the use of derivative instruments. In the normal course of business, QEP uses commodity derivative instruments to reduce the impact of downward movements in commodity prices on cash flow, returns on capital, 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. In addition, QEP may enter into commodity derivative contracts on a portion of its extracted NGL volumes in its midstream business and a portion of its natural gas sales and purchases for marketing transactions. QEP does not enter into commodity derivative instruments for speculative purposes.

QEP uses commodity derivative instruments known as fixed-price swaps and costless collars to realize a known price or range of prices for a specific volume of production delivered into a regional sales point. Costless collars are combinations of put and call options that have a floor price and a ceiling price and payments are made or received only if the settlement price is outside the range between the floor and ceiling prices. QEP's commodity derivative instruments do not require the physical delivery of natural gas, crude oil, or NGL between the parties at settlement. Swap and costless collar 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. Natural gas price derivative instruments are typically structured as fixed-price swaps at regional price indices. Oil price derivative instruments are typically structured as NYMEX fixed-price swaps based at Cushing, Oklahoma. NGL price derivative instruments are typically structured as Mont Belvieu, Texas fixed-price swaps.

QEP enters into commodity derivative transactions that do not have commodity 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.

Effective January 1, 2012, QEP elected to de-designate all of its natural gas, crude oil and NGL derivative contracts that were previously designated as cash flow hedges and discontinue hedge accounting prospectively. As a result of discontinuing hedge accounting, the mark-to-market values at December 31, 2011, were fixed in AOCI as of the de-designation date and are being reclassified into the Consolidated Statement of Operations as the transactions settle and affect earnings. At December 31, 2012, AOCI consisted of $123.5 million ($77.6 million after tax) of unrealized gains. During 2012, $171.1 million unrealized gains, after tax, were reclassified from AOCI into the Consolidated Statement of Operations in "Realized and unrealized gains on derivative contracts" as the transactions settled. QEP expects to reclassify into earnings from AOCI the remaining fixed value related to de-designated natural gas, oil and NGL hedges during 2013. Currently, QEP recognizes all gains and losses from changes in the fair value of natural gas, oil and NGL derivative contracts immediately in earnings rather than deferring any such amounts in AOCI. All commodity derivative instruments are recorded on the Consolidated Balance Sheets as either assets or liabilities measured at their fair values. All realized and unrealized gains and losses from derivative instruments incurred after January 1, 2012, are presented in the Consolidated Statement of Operations in "Realized and unrealized gains on derivative contracts" below operating income.

QEP also uses interest rate swaps to mitigate a portion of its exposure to interest rate volatility risk. During the second quarter of 2012, QEP entered into variable-to-fixed interest rate swap agreements having a combined notional principal amount of $300.0 million to minimize the interest rate volatility risk associated with its $300.0 million term loan. QEP locked in a fixed interest rate in exchange for a variable interest rate indexed to the one-month LIBOR rate. The interest rate swaps are valued at mark-to-market, settle monthly and will mature in March of 2017.

QEP Energy Derivative Contracts

The following table sets forth QEP Energy's quantities and average prices for its commodity derivative contracts as of December 31, 2012:

Year	Type of Contract	Index	Total Volumes	Swaps	
				Average price per unit	
			(in millions)		
Natural gas sales			**(MMBtu)**		
2013	Swap	NYMEX	51.1	$	3.79
2013	Swap	IFNPCR	65.7	$	5.66
2014	Swap	NYMEX	18.3	$	4.21
Oil sales			**(Bbls)**		
2013	Swap	NYMEX WTI	5.1	$	98.48
2014	Swap	NYMEX WTI	1.8		92.72

QEP Marketing Derivative Contracts

QEP Marketing enters into commodity derivative transactions to lock in a margin on natural gas volumes placed into storage and for marketing transactions in which QEP Marketing is required to sell 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, 2012:

Year	Type of Contract	Index	Total Volumes	Average Swap price per MMBtu	
			(in millions)		
Natural gas sales			**(MMBtu)**		
2013	Swap	IFNPCR	4.0	$	3.78
Natural gas purchases			**(MMBtu)**		
2013	Swap	IFNPCR	0.2	$	2.88
2014	Swap	IFNPCR	0.1	$	3.02

QEP Resources Derivative Contracts

In the second quarter of 2012, QEP Resources entered into interest rate swap agreements to effectively lock in a fixed interest rate on debt outstanding under its Term Loan. The following table sets forth QEP Resources' notional amounts and interest rates for its interest rate swaps outstanding as of December 31, 2012:

Notional amount	Type of Contract	Maturity	Fixed Rate Paid	Variable Rate Received
(in millions)				
$300.0	Swap	March 2017	1.07%	One month LIBOR

QEP Derivative Financial Statement Presentation

The following table presents the 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	**2012**	2011	**2012**	2011
		(in millions)		(in millions)	
Current:					
Commodity	Fair value of derivative contracts	**$ 189.7**	$ 284.1	**$ 1.0**	$ 11.7
Interest rate swaps	Fair value of derivative contracts	**—**	—	**2.6**	—
Long-term:					
Commodity	Fair value of derivative contracts	**4.2**	123.5	**0.1**	—
Interest rate swaps	Fair value of derivative contracts	**—**	—	**3.6**	—
Total derivative instruments		**$ 193.9**	$ 407.6	**$ 7.3**	$ 11.7

The effects and location of the change in fair value and settlement of QEP's derivative contracts on the Consolidated Statements of Operations are summarized in the following tables:

	Year Ended December 31,		
Derivative instruments not designated as cash flow hedges [(1)]	**2012**	2011	2010
Realized gain (loss) on commodity derivative contracts			
QEP Energy			
Natural gas derivative contracts	**$ 341.9**	$ (117.7)	$ (121.7)
Oil derivative contracts	**14.4**	—	—
NGL derivative contracts	**10.2**	—	—
QEP Field Services			
NGL derivative contracts	**8.4**	—	—
QEP Marketing			
Natural gas derivative contracts	**5.1**	—	—
Total realized gain (loss) on commodity derivative contracts	**380.0**	(117.7)	(121.7)
Unrealized gain (loss) on commodity derivative contracts			
QEP Energy			
Natural gas derivative contracts	**37.8**	117.7	121.7
Oil derivative contracts	**29.0**	—	—
NGL derivative contracts	**1.6**	—	—
QEP Field Services			
NGL derivative contracts	**—**	—	—
QEP Marketing			
Natural gas derivative contracts	**0.9**	—	—
Total unrealized gain on commodity derivative contracts	**69.3**	117.7	121.7
Total realized and unrealized gain on commodity derivative contracts	**$ 449.3**	$ —	$ —
Realized gain (loss) on interest rate swaps			
Realized loss on interest rate swaps	**$ (1.3)**	$ —	$ —
Unrealized gain (loss) on interest rate swaps			
Unrealized loss on interest rate swaps	**(6.1)**	—	—
Total realized and unrealized loss on interest rate swaps	**$ (7.4)**	$ —	$ —
Total net realized gain on derivative contracts	**$ 378.7**	$ (117.7)	$ (121.7)
Total net unrealized gain on derivative contracts	**$ 63.2**	$ 117.7	$ 121.7
Grand Total	**$ 441.9**	$ —	$ —

[(1)] Gains and losses on derivatives not designated as cash flow hedges, are included in earnings in "Realized and unrealized gains on derivative contracts" on the Consolidated Statement of Operations.

The following table presents the change in the fair value and settlement of QEP's derivative contracts that were designated as cash flow hedges in 2011 and 2010:

Derivative instruments classified as cash flow hedges	**Location of gain (loss) recognized in earnings**	December 31,		
		2012	2011	2010
Commodity derivatives				
Gain on derivative instruments for the effective portion of hedge recognized in AOCI	Accumulated other comprehensive income	$ —	$ 350.8	$ 565.8
Gain reclassified from AOCI into income for effective portion of hedge	Natural gas sales	—	305.5	353.8
Gain reclassified from AOCI into income for effective portion of hedge	Oil sales	—	1.6	(8.7)
Gain reclassified from AOCI into income for effective portion of hedge	NGL sales	—	(0.2)	—
Gain reclassified from AOCI into income for effective portion of hedge	Marketing purchases	—	4.3	3.1
Gain recognized in income for the ineffective portion of hedges	Interest and other income	—	0.1	0.2

The Company estimates that the remaining derivative contracts that were outstanding in AOCI at December 31, 2012, with a fixed fair value of $77.6 million after tax, will be settled and reclassified from AOCI to the Consolidated Statements of Operations during the next twelve months.

Note 7 – Restructuring Costs

During the first quarter 2012, QEP began incurring costs related to the closure of its Oklahoma City office and the subsequent consolidation of its Southern Region operations into a single regional office located in Tulsa. During the second half of 2012, QEP incurred additional restructuring and reorganization costs related to consolidating various corporate and accounting functions to the Denver corporate headquarters. The creation of one office for QEP's Southern Region as well as consolidation of corporate and accounting functions is intended to increase efficiency, team-based collaboration and organizational productivity over the long term. As part of the reorganization, QEP incurred and will continue to incur costs associated with the severance, retention and relocation of employees, additional pension expenses, exit costs associated with the termination of operating leases arising from office space that will no longer be utilized by the Company and other expenses. The Company currently estimates that the remaining restructuring costs will be incurred during 2013.

The following table summarizes, by line of business, each major type of costs expected to be incurred and the total amounts recorded in "General and administrative" expense on the Consolidated Statement of Operations the respective periods indicated:

	QEP Energy	QEP Field Services	QEP Marketing	Total
Restructuring costs expected to be incurred		(in millions)		
One-time termination benefits	**$ 3.3**	**$ —**	**$ 0.2**	**$ 3.5**
Retention and relocation expense	**5.4**	**0.2**	**0.2**	**5.8**
Lease termination costs and other expenses	**0.6**	**—**	**—**	**0.6**
Total restructuring costs expected to be incurred	**$ 9.3**	**$ 0.2**	**$ 0.4**	**$ 9.9**
Total restructuring costs recognized in income for the year ended December 31, 2012				
One-time termination benefits	**$ 2.9**	**$ —**	**$ 0.1**	**$ 3.0**
Retention and relocation expense	**3.4**	**—**	**—**	**3.4**
Lease termination costs and other expenses	**0.6**	**—**	**—**	**0.6**
Total restructuring costs incurred during the year ended December 31, 2012	**$ 6.9**	**$ —**	**$ 0.1**	**$ 7.0**

In addition to the costs incurred above, during the year ended December 31, 2012, the Company recognized a curtailment loss of $2.2 million as part of its pension plan's net periodic benefit cost. The curtailment loss was a result of the Company's restructuring efforts and termination benefits and is included on the Consolidated Balance Sheet as part of the Company's pension liability. For additional information related to the Company's pension plans, see Note 11 - Employee Benefits. The following is a reconciliation of the restructuring liability, by line of business, which is included within "Accounts payable and accrued expenses" on the Consolidated Balance Sheets:

	QEP Energy	QEP Field Services	QEP Marketing	Total
		(in millions)		
Balance at December 31, 2011	$ —	$ —	$ —	$ —
Costs incurred and charged to expense	**6.9**	**—**	**0.1**	**7.0**
Costs paid or otherwise settled	**(5.9)**	**—**	**(0.1)**	**(6.0)**
Balance at December 31, 2012	**$ 1.0**	**—**	**—**	**$ 1.0**

Note 8 – Debt

As of the indicated dates, the principal amount of QEP's debt, including amounts outstanding under its revolving credit facility and term loan agreement, consisted of the following:

	December 31,	
	2012	2011
	(in millions)	
Revolving credit facility due 2016	**$ 690.0**	$ 606.5
Term loan due 2017	**300.0**	—
6.05% Senior Notes due 2016	**176.8**	176.8
6.80% Senior Notes due 2018	**134.0**	138.6
6.80% Senior Notes due 2020	**136.0**	138.0
6.875% Senior Notes due 2021	**625.0**	625.0
5.375% Senior Notes due 2022	**500.0**	—
5.25% Senior Notes due 2023	**650.0**	—
Total principal amount of debt	**3,211.8**	1,684.9
Less unamortized discount	**(4.9)**	(5.5)
Total long-term debt outstanding	**$ 3,206.9**	$ 1,679.4

Of the total debt outstanding on December 31, 2012, the revolving credit facility due August 25, 2016, the term loan due April 18, 2017, and the 6.05% Senior Notes due September 1, 2016, will mature within the next five years.

Credit Facility

QEP's revolving credit facility agreement, which matures in August 2016, provides for loan commitments of $1.5 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 facility agreement also contains an accordion provision that would allow for the amount of the facility to be increased to $2.0 billion and for the maturity to be extended for two additional one-year periods, with the agreement of the lenders.

During the year ended December 31, 2012, QEP's weighted-average interest rate on borrowings from its credit facility was 2.08%. At December 31, 2012 and 2011, QEP was in compliance with the covenants under the credit agreement. At December 31, 2012, there was $690.0 million outstanding and QEP had $4.1 million in letters of credit outstanding under the credit facility.

Term Loan
During the second quarter of 2012, QEP entered into a $300.0 million senior, unsecured term loan agreement with a group of financial institutions. The term loan provides for borrowings at short-term interest rates and contains covenants, restrictions and interest rates that are substantially the same as the Company's credit facility. The term loan matures in April 2017, and the maturity date may be extended one year with the agreement of the lenders. The proceeds from the term loan were used to pay down the credit facility and for general corporate purposes. During the year ended December 31, 2012, QEP's weighted-average interest rate on borrowings from the term loan was 2.05%. At December 31, 2012, QEP was in compliance with the covenants under the term loan credit agreement.

Senior Notes
During the first quarter of 2012, QEP completed a public offering of $500.0 million in aggregate principal amount of 5.375% senior notes due in October 2022. The 2022 senior notes were issued at par. Interest on the notes will be paid semi-annually, in April and October of each year. The net proceeds of $493.1 million were used to repay indebtedness under QEP's credit facility. The finance costs associated with the offering were $6.9 million and were deferred and are being amortized over the life of the notes.

During the second quarter of 2012, QEP repurchased $6.7 million of its senior notes outstanding. QEP recognized a loss on extinguishment of debt from those repurchases and associated write-offs of debt issuance costs, discounts and premiums paid of $0.6 million.

During the third quarter of 2012, QEP completed a public offering of $650.0 million in aggregate principal amount of 5.25% senior notes due in May 2023. The notes were issued at par. Interest on the notes will be paid semi-annually, in May and November of each year. The net proceeds of $641.0 million were used to fund a portion of the 2012 Acquisition, as described in Note 2 - Acquisition. The costs associated with the offering were $9.0 million and were deferred and are being amortized over the life of the notes. The amortization expense related to all of the Company's deferred finance costs is included in "Interest expense" on the Consolidated Statement of Operations.

At December 31, 2012, 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 indenture governing QEP's senior notes contains customary events of default and covenants that may limit QEP's ability to, among other things, place liens on its property or assets.

Note 9 – Commitments and Contingencies

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 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. Because legal proceedings are inherently unpredictable and unfavorable resolutions could 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, and/or the ongoing discovery and development of information important to the matters. QEP regularly reviews contingencies to determine the adequacy of its accruals and related disclosures. The following discussion describes the nature of QEP's material loss contingencies.

Environmental Claims

United States of America v. QEP Field Services, Civil No. 208CV167, U.S. District Court for Utah filed on February 28, 2008. The U.S. Environmental Protection Agency (EPA) alleged that QEP Field Services (f/k/a Questar Gas Management) violated the Clean Air Act (CAA) and sought substantial penalties and a permanent injunction involving the manner of operation of five compressor stations located in the Uinta Basin of eastern Utah. On May 16, 2012, QEP Field Services settled this matter and the parties executed a consent decree which was subsequently approved by court order. The civil penalty paid to the government during the third quarter of 2012 was $3.7 million. A contribution of $0.4 million was paid to a trust created by the Ute Indian Tribe of the Uintah and Ouray Reservation for the implementation of environmental programs for the benefit of Tribal members. The settlement also requires the Company to reduce its emissions by removing certain equipment, installing additional pollution controls and replacing the natural gas powered instrument control systems with compressed air control systems, all of which will require capital expenditures of approximately $2.4 million, of which $1.2 million had been spent as of December 31, 2012. QEP Field Services will have continuing operational compliance obligations under the consent decree at the affected facilities.

In October 2009, the Company received a cease and desist order from the U.S. Army Corps of Engineers (COE) to refrain from unpermitted work resulting in the discharge of dredged and/or fill material into waters of the United States at three sites located in Caddo and Red River Parishes, Louisiana. EPA Region 6 has assumed lead responsibility for enforcement of the cease and desist order and any possible future orders for the removal of unauthorized fills and/or civil penalties under the Clean Water Act. In 2012, the Company completed a field audit, which identified 112 additional instances affecting approximately 90 acres where work may have been conducted in violation of the Clean Water Act. The Company has disclosed each of these instances to the EPA under the EPA's Audit Policy (to reduce penalties) and to the COE. The Company is working with the EPA and the COE to resolve these matters, which will require the Company to undertake certain mitigation and permitting activities, and may require the Company to pay a monetary penalty. At this time, QEP is unable to estimate the potential loss related to this matter, but believes it exceeds the $100,000 threshold for disclosure of environmental matters.

Litigation

Chieftain Royalty Company v. QEP Energy Company, Case No CJ2011-1, U. S. District Court for the Western District of Oklahoma. This statewide class action was filed on January 20, 2011, on behalf of QEP's Oklahoma royalty owners asserting various claims for damages related to royalty valuation on all of QEP's Oklahoma wells operated by QEP or from which QEP marketed gas. These claims include breach of contract, breach of fiduciary duty, fraud, unjust enrichment, tortious breach of contract, conspiracy, and conversion, based generally on asserted improper deduction of post-production costs. The Court certified the class as to the breach of contract, breach of fiduciary duty and unjust enrichment claims. The parties successfully mediated the case in January 2013. On February 13, 2013, the parties executed a Stipulation and Agreement of Settlement (the Chieftain Settlement Agreement) providing for a cash payment from QEP to the class in the amount of $115.0 million. In consideration for the settlement payment, QEP will receive a full release of all claims regarding the calculation, reporting and payment of royalties from the sale of natural gas and its constituents for all periods prior to February 28, 2013, and all class members are enjoined from asserting claims related to such royalties. As part of the Chieftain Settlement Agreement, the parties also agreed on the methodology for the calculation and payment of future royalties payable by QEP, or its successors and assigns, under all class leases for the life of such leases. The Court has entered a Preliminary Order Approving Class Action Settlement. During the year ended December 31, 2012, QEP recorded a loss contingency accrual of $115.0 million, which is included in "General and administrative" expense on the Consolidated Statement of Operations. The accrual is included in "Accounts payable and accrued expenses" on the Consolidated Balance Sheet.

Questar Gas Company v. QEP Field Services Company, Civil No. 120902969, Third Judicial District Court, State of Utah. QEP Field Services' former affiliate Questar Gas Company (QGC) filed this complaint in state court in Utah on May 1, 2012, asserting claims for breach of contract, breach of implied covenant of good faith and fair dealing, for an accounting and declaratory judgment related to a 1993 gathering agreement (1993 Agreement) entered when the parties were affiliates. Under the 1993 Agreement, QEP Field Services provides gathering services for producing properties developed by former affiliate Wexpro Company on behalf of QGC's utility ratepayers. The core dispute pertains to the annual calculation of the gathering rate, which is based on a cost of service concept expressed in the 1993 Agreement and in a 1998 amendment. The annual gathering rate has been calculated in the same manner under the contract since it was amended in 1998, without any prior objection or challenge by QGC. Specific monetary damages are not asserted. Also, on May 1, 2012, QEP Field Services Company filed a legal action against Questar Gas entitled *QEP Field Services Company v. Questar Gas Company*, in the Second District Court in Denver County, Colorado, seeking declaratory judgment relating to its gathering service and charges under the same agreement.

Commitments

Subsidiaries of QEP have contracted for firm-transportation 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 and fractionation contracts. Annual payments and the corresponding years for transportation contracts, drilling contracts and fractionation contracts are as follows (in millions):

Year		Amount
2013	$	**161.3**
2014	$	**146.2**
2015	$	**112.0**
2016	$	**107.7**
2017	$	**107.0**
After 2017	$	**385.7**

QEP rents office space throughout its scope of operations from third-party lessors. Rental expense from operating leases amounted to $7.3 million, $5.0 million and $4.5 million during the years ended December 31, 2012, 2011 and 2010, respectively. Minimum future payments under the terms of long-term operating leases for the Company's primary office locations are as follows (in millions):

Year		Amount
2013	$	6.7
2014	$	6.5
2015	$	6.6
2016	$	6.5
2017	$	6.7
After 2017	$	29.1

Note 10 – Share-Based Compensation

QEP issues stock options and restricted shares under its Long-Term Stock Incentive Plan (LTSIP) and awards performance-based share units under its Cash Incentive Plan (CIP) to certain officers, employees, and non-employee directors. QEP recognizes expense over time as the stock options, restricted shares, and performance-based share units vest. Deferred share-based compensation is included in additional paid-in capital in the Consolidated Balance Sheets. There were 13.1 million shares available for future grants under the LTSIP at December 31, 2012. Share-based compensation expense is recognized in "General and administrative" on the Consolidated Statements of Operations. During the year ended December 31, 2012, QEP recognized $25.6 million in total compensation expense related to share-based compensation compared to $22.0 million and $16.1 million during the years ended December 31, 2011 and 2010, respectively.

Stock Options

QEP uses the Black-Scholes-Merton mathematical model to estimate the fair value of stock options 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.

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

	Stock Option Variables		
	Year Ended December 31,		
	2012	2011	2010
Weighted-average grant-date fair value of awards granted during the period	**$ 14.29**	$ 18.80	$ 27.55
Risk-free interest rate range	**0.63% - 1.04%**	n/a	n/a
Weighted-average risk-free interest rate	**0.8%**	2.1%	2.3%
Expected price volatility range	**55.9% - 56.5%**	n/a	n/a
Weighted-average expected price volatility	**55.9%**	54.7%	30.3%
Expected dividend yield	**0.26%**	0.21%	1.18%
Expected term in years at the date of grant	**5.0**	5.0	5.2

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

	Options Outstanding	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
		(per share)	(in years)	(in millions)
Outstanding at December 31, 2011	2,003,694	$ 21.23		
Granted	**304,660**	**30.75**		
Exercised	**(610,883)**	**14.87**		
Forfeited	**—**	**—**	—	
Outstanding at December 31, 2012	**1,697,471**	**$ 25.23**	**3.64**	**$ 10.5**
Options Exercisable at December 31, 2012	**1,230,843**	**$ 22.50**	**2.88**	**$ 10.3**
Unvested Options at December 31, 2012	**466,628**	**$ 32.40**	**5.65**	**$ 0.2**

The total intrinsic value (the difference between the market price at the exercise date and the exercise price) of options exercised was $9.6 million, $2.7 million and $0.3 million during the years ended December 31, 2012, 2011 and 2010, respectively. The Company realized $4.6 million and $0.4 million of income tax benefits for the years ended December 31, 2012 and 2011 (no income tax benefit realized in 2010), which increased its Additional Paid-in-Capital (APIC) pool by $5.1 million as of December 31, 2012. As of December 31, 2012, $2.7 million of unrecognized compensation cost related to stock options granted under the LTSIP is expected to be recognized over a weighted-average period of 1.99 years. During the year ended December 31, 2012, QEP issued shares for stock option exercises from its treasury stock. During the year end December 31, 2012, QEP received $2.6 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, 2012 and 2011, was $16.7 million and $11.7 million, respectively, with minimal vestings in 2010. The Company realized $0.3 million income tax expense and $1.0 million income tax benefit for the years ended December 31, 2012 and 2011, respectively, and increased the Company's APIC pool by $0.9 million as of December 31, 2012. The weighted average grant-date fair value of restricted stock granted during the years was $30.54 per share, $38.50 per share and $28.70 per share for the years ended December 31, 2012, 2011 and 2010, respectively. As of December 31, 2012, $16.5 million of unrecognized compensation cost related to restricted shares granted under the LTSIP is expected to be recognized over a weighted-average vesting period of 2.09 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, 2011	1,099,752	$	32.80
Granted	**827,986**		30.54
Vested	**(541,230)**		31.90
Forfeited	**(85,920)**		32.30
Unvested balance at December 31, 2012	**1,300,588**	**$**	**31.78**

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 but delivered in cash at the end of the performance period. The weighted average grant-date fair value of the performance share units granted during the period was $30.90 per unit and $39.07 per unit for the years ended December 31, 2012 and 2011, respectively. As of December 31, 2012, $3.2 million of unrecognized compensation cost classified as a liability, or the fair market value, related to performance shares granted under the CIP is expected to be recognized over a weighted-average vesting period of 1.90 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
Unvested balance at December 31, 2011	115,274	$	39.07
Granted	**180,923**		**30.90**
Vested	**—**		**—**
Forfeited	**(12,713)**		**35.69**
Unvested balance at December 31, 2012	**283,484**	**$**	**34.01**

Note 11 – Employee Benefits

Defined Benefit Pension Plans and Other Postretirement Benefits
The Company maintains closed, defined-benefit pension and postretirement medical plans providing coverage to 145, or 16%, of QEP's active employees and to 70 participants that are retired, terminated and vested, or suspended. 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. QEP pension plans include a qualified and a nonqualified retirement plan. Postretirement health care benefits and life insurance are provided only to employees hired before January 1, 1997. The Company pays a portion of the costs of health-care benefits determined by an employee's years of service. The Company has capped its exposure to increasing medical care and life insurance costs by paying a fixed dollar monthly contribution toward these retiree benefits. The Company 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. At December 31, 2012 and 2011, QEP's accumulated benefit obligation exceeded the fair value of plan assets as the plan is unfunded.

During the year ended December 31, 2012, the Company recognized a $2.2 million loss on curtailment as part of its restructuring efforts and related termination benefits. A curtailment is recognized immediately when there is a significant reduction in, or an elimination of, defined benefit accruals for present employees' future services. For additional information regarding the Company's restructuring efforts see Note 7 - Restructuring Costs. During the year ended December 31, 2012, the Company made contributions of $5.6 million to its funded pension plan, and $1.3 million to its unfunded pension plan. Contributions to funded plans increase plan assets while contributions to unfunded plans are used to fund current benefit payments. During 2013, the Company expects to contribute approximately $8.1 million to its funded pension plan, approximately $3.2 million to its unfunded pension plan and approximately $0.2 million for retiree health care and life insurance benefits. The accumulated postretirement benefit obligation for all defined-benefit pension plans was $106.9 million and $78.3 million at December 31, 2012 and 2011, respectively.

The following table sets forth changes in the benefit obligations and fair value of plan assets for the Company's pension and other postretirement benefit plans for the years ended December 31, 2012 and 2011, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2012 and 2011:

	Pension benefits		Other postretirement benefits	
	2012	2011	**2012**	2011
	(in millions)			
Change in benefit obligation				
Benefit obligation at January 1,	**$ 104.1**	$ 78.0	**$ 5.9**	$ 4.5
Service cost	**4.0**	2.9	**0.1**	0.1
Interest cost	**5.1**	4.5	**0.3**	0.3
Change in plan assumptions	**8.4**	19.6	**—**	—
Benefit payments	**(2.7)**	(0.2)	**—**	—
Actuarial loss (gain)	**10.8**	(0.7)	**0.4**	1.0
Benefit obligation at December 31,	**$ 129.7**	$ 104.1	**$ 6.7**	$ 5.9
Change in plan assets				
Fair value of plan assets at January 1,	**$ 44.2**	$ 30.9	**$ —**	$ —
Actual gain (loss) on plan assets	**6.9**	(1.3)	**—**	—
Company contributions to the plan	**6.9**	14.8	**—**	—
Benefit payments	**(2.7)**	(0.2)	**—**	—
Fair value of plan assets at December 31,	**55.3**	44.2	**—**	—
Underfunded status (current and long-term)	**$ (74.4)**	$ (59.9)	**$ (6.7)**	$ (5.9)
Amounts recognized in balance sheets				
Accounts payable and accrued expenses	**$ (3.2)**	$ (1.3)	**$ (0.2)**	$ —
Other long-term liabilities	**(71.2)**	(58.6)	**(6.5)**	(5.9)
Total amount recognized in balance sheet	**$ (74.4)**	$ (59.9)	**$ (6.7)**	$ (5.9)
Amounts recognized in AOCI				
Net actuarial loss (gain)	**$ 32.6**	$ 18.6	**$ 1.3**	$ 1.0
Prior service cost	**35.1**	42.6	**3.4**	3.8
Total amount recognized in AOCI	**$ 67.7**	$ 61.2	**$ 4.7**	$ 4.8

The following table sets forth the Company's pension and other postretirement benefit cost and amounts recognized in other comprehensive income (before tax) for the respective years ended December 31:

	Pension benefits			Other postretirement benefits		
	2012	2011	2010	**2012**	2011	2010
Components of net periodic benefit cost						
Service cost	**$ 4.0**	$ 2.9	$ 1.3	**$ 0.1**	$ 0.1	$ 0.1
Interest cost	**5.1**	4.5	2.1	**0.3**	0.3	0.1
Expected return on plan assets	**(3.6)**	(2.6)	(1.1)	**—**	—	—
Curtailment loss	**2.2**	—	—	**—**	—	—
Amortization of prior service costs	**5.3**	5.3	2.6	**0.3**	0.3	0.2
Amortization of actuarial loss	**1.9**	—	—	**0.1**	—	—
Periodic expense	**$ 14.9**	$ 10.1	$ 4.9	**$ 0.8**	$ 0.7	$ 0.4
Components recognized in accumulated other comprehensive income						
Current period actuarial loss (gain)	**$ 15.9**	$ 22.9	$ (4.2)	**$ 0.4**	$ 1.0	$ —
Amortization of actuarial loss	**(1.9)**	—	—	**(0.1)**	—	—
Current period prior service cost	**—**	—	50.4	**—**	—	4.3
Amortization of prior service cost	**(5.3)**	(5.3)	(2.6)	**(0.4)**	(0.3)	(0.1)
Loss on curtailment in current period	**(2.2)**	—	—	**—**	—	—
Total amount recognized in accumulated other comprehensive income	**$ 6.5**	$ 17.6	$ 43.6	**$ (0.1)**	$ 0.7	$ 4.2

The estimated portion of net actuarial loss and net prior service cost for the pension plans that will be amortized from AOCI into net periodic benefit cost in 2013 is $7.3 million, of which $5.0 million represents amortization of prior service cost recognition and the remaining $2.3 million represents amortization of net actuarial losses. The estimated portion to be recognized in net periodic cost for other postretirement benefits from AOCI in 2013 is $0.5 million, of which $0.4 million represents amortization of prior service cost recognition and the remaining $0.1 million represents amortization of net actuarial losses.

Following are the weighted-average assumptions (weighted by the plan level benefit obligation for pension benefits) used by the Company to calculate pension and other postretirement benefit obligations at December 31, 2012 and 2011:

	Pension benefits		Other postretirement benefits	
	2012	2011	**2012**	2011
Discount rate	**3.88%**	4.54%	**4.10%**	4.70%
Rate of increase in compensation	**3.60%**	3.60%	**3.60%**	4.00%

The discount rate assumptions used by the Company represents an estimate of the interest rate at which the pension and other postretirement 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 and other postretirement benefit cost for the years ended December 31:

	Pension benefits			Other postretirement benefits		
	2012	2011	2010	**2012**	2011	2010
Discount rate	**4.38%**	5.80%	5.70%	**4.70%**	5.80%	5.70%
Expected long-term return on plan assets	**7.25%**	7.50%	7.50%	**n/a**	n/a	n/a
Rate of increase in compensation	**3.60%**	3.60%	3.60%	**4.00%**	n/a	n/a

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 2013. Historical heath 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 increase and decreases in the health-care inflation rate is not applicable.

Plan Assets

The Company's Employee Benefits Committee (EBC) oversees investment of 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 committee'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 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 mostly invested in a stock index fund, and a smaller portion was invested in an actively managed product, 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.

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.

The fair value measurement provision of ASC 820, *Fair Value Measurements*, defines fair value in applying generally accepted accounting principles as well as establishes a framework for measuring fair value and for making disclosures about fair-value measurements. Fair value measurement establishes a fair-value hierarchy. Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that are accessible at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for an asset, either directly or indirectly. Level 3 inputs are unobservable inputs for an asset. 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 pension and postretirement benefit assets.:

	As of December 31, 2012				
	Level 1	Level 2	Level 3	Total	Percentage of total
	(in millions except percentages)				
Cash and short-term investments	$ —	$ —	$ 0.2	$ 0.2	—%
Equity securities:					
Domestic	—	—	22.2	22.2	40%
International	—	—	16.7	16.7	30%
Fixed income	—	—	16.2	16.2	30%
Total investments	—	—	$ 55.3	$ 55.3	100%

	As of December 31, 2011				
	Level 1	Level 2	Level 3	Total	Percentage of total
	(in millions except percentages)				
Cash and short-term investments	$ —	$ —	$ —	$ —	$ —
Equity securities:					
Domestic	—	—	17.6	17.6	40%
International	—	—	13	13.0	29%
Fixed income	—	—	13.6	13.6	31%
Total investments	—	—	$ 44.2	$ 44.2	100%

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

	Year ended December 31,	
	2012	2011
	(in millions)	
Balance at January 1,	$ 44.2	30.9
Employer contributions	5.6	14.8
Unrealized gains (losses)	6.3	(1.4)
Realized gains	0.7	0.3
Administrative fees	(0.2)	(0.2)
Benefits paid	(1.3)	(0.2)
Balance at December 31,	$ 55.3	$ 44.2

Expected Benefit Payments
As of December 31, 2012, the following future benefit payments are expected to be paid:

	Pension	Postretirement benefits
	(in millions)	
2013	$ 5.7	$ 0.2
2014	5.3	0.2
2015	4.9	0.2
2016	5.6	0.3
2017	5.2	0.3
2018 through 2021	40.9	1.8

Employee Investment Plan
QEP employees may participate in the QEP Employee Investment Plan (EIP), a defined-contribution plan. The EIP allows eligible employees to purchase shares of QEP common stock or other investments through payroll deduction at the current fair market value on the transaction date. The Company currently contributes an overall match of 100% of employees' contribution up to a maximum of 6% of their qualifying earnings. In addition, from time-to-time at the discretion of management, the

Company may contribute a discretionary portion beyond the company match to employees not in the Company's closed defined benefit plan. The Company recognizes expense equal to its yearly contributions, which amounted to $6.4 million, $5.8 million and $4.2 million during the years ended December 31, 2012, 2011 and 2010.

Note 12 - Income Taxes

Details of income tax expenses and deferred income taxes from continuing operations are provided in the following tables. The components of income tax expenses were as follows:

	Year Ended December 31,		
	2012	2011	2010
		(in millions)	
Federal income tax expense (benefit)			
Current	**$ 33.7**	$ (5.3)	$ (16.6)
Deferred	**36.5**	153.0	172.9
State income tax expense (benefit)			
Current	**0.7**	2.9	(4.7)
Deferred	**(4.4)**	3.8	15.4
Total income tax expense	**$ 66.5**	**$ 154.4**	**$ 167.0**

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,		
	2012	2011	2010
Federal income taxes statutory rate	**35.0 %**	35.0 %	35.0 %
Increase (decrease) in rate as a result of:			
State income taxes, net of federal income tax benefit	**(1.2)%**	1.0 %	1.5 %
Penalties	**(0.6)%**	— %	— %
Return to provision adjustment	**0.4 %**	1.3 %	0.2 %
Noncontrolling interest	**(0.7)%**	(0.3)%	(0.2)%
Non-deductible Spin-off costs	**— %**	— %	0.5 %
Other	**0.6 %**	(0.7)%	(0.1)%
Effective income tax rate	**33.5 %**	36.3 %	36.9 %

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

	December 31,	
	2012	2011
	(in millions)	
Deferred tax liabilities		
Property, plant and equipment	**$ 1,606.6**	$ 1,714.6
Commodity price and interest rate derivatives	**69.4**	147.2
Total deferred tax liabilities	**1,676.0**	1,861.8
Deferred tax assets		
NOL and tax credit carryforwards	**65.6**	232.9
Employee benefits and compensation costs	**47.7**	42.9
Accrued litigation loss contingency	**42.8**	—
Bonus and vacation accrual	**11.8**	10.7
Other	**9.6**	5.2
Total deferred tax assets	**177.5**	291.7
Net deferred income tax liability	**$ 1,498.5**	$ 1,570.1
Balance sheet classification		
Deferred income tax liability - current	**$ 5.0**	$ 85.4
Deferred income tax liability - non-current	**1,493.5**	1,484.7
Net deferred income tax liability	**$ 1,498.5**	$ 1,570.1

Federal and state income tax NOLs and credits declined significantly at December 31, 2012, compared to December 31, 2011, due to an election to capitalize and amortize certain intangible drilling costs in order to minimize alternative minimum tax. The amounts and expiration dates of operating loss and tax credit carryforwards at December 31, 2012:

	Expiration Dates	Amounts
		(in millions)
State net operating loss and credit carryforwards	2014-2032	**$ 21.2**
U.S. alternative minimum tax credit	Indefinite	**44.4**
Total		**$ 65.6**

Note 13 - Discontinued Operations

Wexpro's operating results prior to the Spin-off are reflected in this Annual Report on Form 10-K as discontinued operations and summarized in the table below:

	Year Ended December 31,		
	2012	2011	2010
	(in millions, except per share amounts)		
Revenues	**$ —**	$ —	$ 131.2
Income before income taxes	**—**	—	67.4
Income taxes	**—**	—	(24.2)
Discontinued operations, net of income taxes	**$ —**	$ —	$ 43.2
Earnings per common share attributable to QEP			
Basic from discontinued operations	**$ —**	$ —	$ 0.25
Diluted from discontinued operations	**—**	—	0.24

Note 14 – Operations by Line of Business

QEP's lines of business include natural gas and oil exploration and production (QEP Energy), midstream field services (QEP Field Services) and marketing (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.

The following table is a summary of operating results for the year ended December 31, 2012, by line of business:

	QEP Energy	QEP Field Services	QEP Marketing & Other	Eliminations	QEP Consolidated
			(in millions)		
Revenues [1]					
From unaffiliated customers	$ 1,615.4	$ 320.2	$ 414.2	$ —	$ 2,349.8
From affiliated customers	—	119.0	605.7	(724.7)	—
Total Revenues	1,615.4	439.2	1,019.9	(724.7)	2,349.8
Operating expenses					
Purchased gas, oil and NGL expense	224.7	12.1	1,021.1	(602.3)	655.6
Lease operating expense	175.8	—	—	(3.5)	172.3
Natural gas, oil and NGL transportation and other handling costs	228.1	33.6	—	(112.8)	148.9
Gathering, processing and other	—	86.8	1.2	—	88.0
General and administrative	237.6	34.7	0.4	(6.1)	266.6
Production and property taxes	97.2	6.0	0.2	—	103.4
Depreciation, depletion and amortization	838.0	63.2	3.7	—	904.9
Abandonment, impairment and exploration expenses	144.6	—	—	—	144.6
Total operating expenses	1,946.0	236.4	1,026.6	(724.7)	2,484.3
Net gain from asset sales	1.2	—	—	—	1.2
Operating (loss) income [1]	(329.4)	202.8	(6.7)	—	(133.3)
Realized and unrealized gains (losses) on derivative contracts	434.9	8.4	(1.4)	—	441.9
Interest and other income	6.2	0.2	132.1	(131.9)	6.6
Income from unconsolidated affiliates	0.1	6.7	—	—	6.8
Loss on early extinguishment of debt	—	—	(0.6)	—	(0.6)
Interest expense	(116.8)	(13.6)	(124.4)	131.9	(122.9)
Income (loss) before income taxes	(5.0)	204.5	(1.0)	—	198.5
Income tax (provision) benefit	4.3	(71.8)	1.0	—	(66.5)
Net income (loss)	(0.7)	132.7	—	—	132.0
Net income attributable to noncontrolling interest	—	(3.7)	—	—	(3.7)
Net income (loss) attributable to QEP [2]	$ (0.7)	$ 129.0	$ —	$ —	$ 128.3
Identifiable total assets	$ 7,436.5	$ 1,399.7	$ 272.3	$ —	$ 9,108.5
Investment in unconsolidated affiliates	—	41.2	—	—	41.2
Cash capital expenditures	2,621.1	164.0	14.6	—	2,799.7
Accrued capital expenditures	2,702.4	171.2	14.6	—	2,888.2
Goodwill	59.5	—	—	—	59.5

(1) The impact of QEP's settled derivative contracts, for the year ended December 31, 2012, are reflected below operating (loss) income.
(2) Net (loss) income attributable to QEP for the year ended December 31, 2012, includes the impact of unrealized gains and losses from changes in the fair value of the commodity derivative contracts.

The following table is a summary of operating results for the year ended December 31, 2011, by line of business:

	QEP Energy	QEP Field Services	QEP Marketing & Other	Eliminations	QEP Consolidated
			(in millions)		
Revenues [1]					
From unaffiliated customers	$ 2,213.2	$ 369.3	$ 576.7	$ —	$ 3,159.2
From affiliated customers	—	96.2	580.2	(676.4)	—
Total Revenues	2,213.2	465.5	1,156.9	(676.4)	3,159.2
Operating expenses					
Purchased gas, oil and NGL expense	506.4	—	1,144.5	(573.8)	1,077.1
Lease operating expense	148.2	—	—	(3.0)	145.2
Natural gas, oil and NGL transportation and other handling costs	186.0	9.3	—	(93.1)	102.2
Gathering, processing and other	—	106.0	1.3	—	107.3
General and administrative	98.4	29.2	2.1	(6.5)	123.2
Production and property taxes	99.1	6.1	0.2	—	105.4
Depreciation, depletion and amortization	707.2	55.7	2.5	—	765.4
Abandonment, impairment and exploration expenses	228.9	—	—	—	228.9
Total operating expenses	1,974.2	206.3	1,150.6	(676.4)	2,654.7
Net gain (loss) from asset sales	1.4	—	—	—	1.4
Operating income [2]	240.4	259.2	6.3	—	505.9
Interest and other income	4.0	0.1	98.7	(98.7)	4.1
Income from unconsolidated affiliates	0.1	5.4	—	—	5.5
Loss on extinguishment of debt	—	—	(0.7)	—	(0.7)
Interest expense	(81.9)	(13.6)	(93.2)	98.7	(90.0)
Income before income taxes	162.6	251.1	11.1	—	424.8
Income taxes	(57.9)	(93.4)	(3.1)	—	(154.4)
Net income	104.7	157.7	8.0	—	270.4
Net income attributable to noncontrolling interest	—	(3.2)	—	—	(3.2)
Net income attributable to QEP [3]	$ 104.7	$ 154.5	$ 8.0	$ —	$ 267.2
Identifiable assets	$ 5,815.7	$ 1,312.7	$ 314.3	$ —	$ 7,442.7
Investment in unconsolidated affiliates	—	42.2	—	—	42.2
Cash capital expenditures	1,295.5	130.1	5.5	—	1,431.1
Accrued capital expenditures	1,338.7	101.6	5.5	—	1,445.8
Goodwill	59.5	—	—	—	59.5

[1] Revenues for the year ended December 31, 2011, reflect the impact of QEP's settled derivative contracts. See Note 6 - Derivative Contracts, for additional information on derivative contract settlements in the year ended December 31, 2011.

[2] Under hedge accounting, realized gains and losses from realized commodity derivative contract settlements were included in revenues and operating income during the year ended December 31, 2011.

[3] Under hedge accounting, unrealized gains and losses from changes in the fair value were deferred in AOCI during the year ended December 31, 2011.

The following table is a summary of operating results for the year ended December 31, 2010, by line of business:

	QEP Energy	QEP Field Services	QEP Marketing & Other	Eliminations	QEP Consolidated
			(in millions)		
Revenues [1]					
From unaffiliated customers	$ 1,456.3	$ 245.5	$ 598.8	$ —	$ 2,300.6
From affiliated customers	—	73.7	499.7	(573.4)	—
Total Revenues	1,456.3	319.2	1,098.5	(573.4)	2,300.6
Operating expenses					
Purchased gas, oil and NGL expense	—	—	1,082.8	(493.5)	589.3
Lease operating expense	127.3	—	—	(2.3)	125.0
Natural gas, oil and NGL transportation and other handling costs	125.5	—	—	(71.3)	54.2
Gathering, processing and other	—	82.1	1.1	—	83.2
General and administrative	78.0	31.6	3.9	(6.3)	107.2
Separation costs	—	—	13.5	—	13.5
Production and property taxes	77.8	4.4	0.3	—	82.5
Depreciation, depletion and amortization	592.5	48.9	2.0	—	643.4
Abandonment, impairment and exploration expenses	69.1	—	—	—	69.1
Total operating expenses	1,070.2	167.0	1,103.6	(573.4)	1,767.4
Net gain (loss) from asset sales	13.7	(1.6)	—	—	12.1
Operating income [2]	399.8	150.6	(5.1)	—	545.3
Interest and other income	2.1	0.1	87.2	(87.1)	2.3
Income from unconsolidated affiliates	0.2	2.8	—	—	3.0
Loss on extinguishment of debt	—	—	(13.3)	—	(13.3)
Interest expense	(78.5)	(7.6)	(85.4)	87.1	(84.4)
Income before income taxes	323.6	145.9	(16.6)	—	452.9
Income taxes	(119.7)	(51.9)	4.6	—	(167.0)
Net income from continuing operations	203.9	94.0	(12.0)	—	285.9
Discontinued operations, net of income tax	—	—	43.2	—	43.2
Net Income	203.9	94.0	31.2	—	329.1
Net income attributable to noncontrolling interest	—	(2.9)	—	—	(2.9)
Net income attributable to QEP [3]	$ 203.9	$ 91.1	$ 31.2	$ —	$ 326.2
Identifiable assets	$ 5,391.9	$ 1,197.5	$ 195.9	$ —	$ 6,785.3
Investment in unconsolidated affiliates	—	44.5	—	—	44.5
Cash capital expenditures	1,205.0	262.1	1.9	—	1,469.0
Accrued capital expenditures	1,215.8	268.2	1.9	—	1,485.9
Goodwill	59.6	—	—	—	59.6

(1) Revenues for the year ended December 31, 2010, reflect the impact of QEP's settled derivative contracts. See Note 6 - Derivative Contracts, for detailed information on derivative contract settlements in the year ended December 31, 2010.
(2) Under hedge accounting, realized gains and losses from realized commodity derivative contract settlements were included in revenues and operating income during the year ended December 31, 2010.
(3) Under hedge accounting, unrealized gains and losses from changes in the fair value were deferred in AOCI during the year ended December 31, 2010.

Note 15 – Subsequent Event

On January 7, 2013, QEP announced that its Board of Directors had authorized the formation of a midstream Master Limited Partnership (MLP) accompanied by the preparation and filing of a registration statement with the SEC for an initial public offering (IPO) of common units of the MLP. The Company expects to file a registration statement with the SEC in the second quarter of 2013. The MLP is intended to support the growth of QEP's midstream business and is consistent with the Company's focus on maximizing shareholder value and maintaining balance sheet strength. The Company expects to initially contribute a majority share of its gathering assets in Wyoming, North Dakota and Utah to the MLP. Subject to final board approval and market conditions, QEP expects to sell a minority interest in the MLP in the IPO and raise approximately $300 million to $400 million in gross proceeds. Proceeds from the offering would be used to fund ongoing operations, to repay debt under the Company's credit facility and for general corporate purposes. Additional detail will be included in the registration statement.

See Note 9 (Commitments and Contingencies) to these consolidated financial statements for a discussion of the mediation and resulting execution of the Chieftain Settlement Agreement in February 2013.

Note 16 – 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)		
2012					
Revenues	**$ 603.2**	**$ 499.3**	**$ 542.4**	**$ 704.9**	**$ 2,349.8**
Operating income (loss)	**49.5**	**(55.5)**	**(12.6)**	**(114.7)**	**(133.3)**
Income (loss) before income taxes	**244.7**	**0.3**	**(4.4)**	**(42.1)**	**198.5**
Net income (loss) attributable to QEP	**155.2**	**(0.7)**	**(3.1)**	**(23.1)**	**128.3**
Per share information attributable to QEP					
Basic EPS attributable to QEP	**$ 0.87**	**$ —**	**$ (0.02)**	**$ (0.13)**	**$ 0.72**
Diluted EPS attributable to QEP	**0.87**	**—**	**(0.02)**	**(0.13)**	**0.72**
2011					
Revenues	$ 617.9	$ 808.1	$ 879.9	$ 853.3	$ 3,159.2
Operating income	137.1	168.9	183.4	16.5	505.9
Income (loss) before income taxes	116.5	147.7	161.5	(0.9)	424.8
Net income (loss) attributable to QEP	73.2	92.8	101.5	(0.3)	267.2
Per share information attributable to QEP					
Basic EPS from continuing operations	$ 0.42	$ 0.52	$ 0.58	$ (0.01)	$ 1.51
Basic EPS attributable to QEP	0.41	0.52	0.57	—	1.50

Note 17 – Supplemental Gas and Oil Information (Unaudited)

The Company is making the following supplemental disclosures of gas and oil 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 gas and oil exploration and development activities. All properties are located in the United States.

Capitalized Costs

The aggregate amounts of costs capitalized for gas and oil exploration and development activities and the related amounts of accumulated depreciation, depletion and amortization are shown below:

	December 31,	
	2012	2011
	(in millions)	
Proved properties	**$ 10,234.3**	$ 8,172.4
Unproved properties, net	**937.9**	326.8
Total proved and unproved properties	**11,172.2**	8,499.2
Accumulated depreciation, depletion and amortization	**(4,258.1)**	(3,339.2)
Net capitalized costs	**$ 6,914.1**	$ 5,160.0

Costs Incurred

The costs incurred in gas and oil exploration and development activities are displayed in the table below. Development costs incurred reflect accrued capital costs of $81.3 million and ARO additions and revisions of $17.7 million during the year ended December 31, 2012. The costs incurred to advance the development of reserves that were classified as proved undeveloped were approximately $513.0 million in 2012, $533.6 million in 2011 and $434.2 million in 2010.

	Year Ended December 31,		
	2012	2011	2010
	(in millions)		
Property acquisitions			
Unproved	**$ 692.6**	$ 48.0	$ 109.1
Proved	**714.4**	0.1	0.2
Total property acquisitions	**1,407.0**	48.1	109.3
Exploration (capitalized and expensed)	**14.3**	36.5	146.4
Development	**1,310.0**	1,267.8	988.8
Total costs incurred	**$ 2,731.3**	$ 1,352.4	$ 1,244.5

Results of Operations

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

	Year Ended December 31,		
	2012	2011	2010
	(in millions)		
Revenues [(1)]	**$ 1,393.4**	$ 1,703.4	$ 1,456.3
Production costs	**501.1**	433.3	330.6
Exploration expenses	**11.2**	10.5	23.0
Depreciation, depletion and amortization	**838.0**	707.2	592.5
Abandonment and impairment	**133.4**	218.4	46.1
Total expenses	**1,483.7**	1,369.4	992.2
Income (loss) before income taxes	**(90.3)**	334.0	464.1
Income tax benefit (expense)	**33.6**	(119.0)	(171.8)
Results of operations from producing activities excluding allocated corporate overhead and interest expenses	**$ (56.7)**	$ 215.0	$ 292.3

(1) Revenue for the years ended December 31, 2011 and 2010, reflect the impact of QEP's settled derivative contracts which during the year ended December 31, 2012, are reflected below operating (loss) income. See Note 6 - Derivative Contracts.

Estimated Quantities of Proved Gas and Oil Reserves

Estimates of proved gas and oil 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., 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, 2012, are scheduled to be developed within five years from the date such locations were initially disclosed as proved undeveloped reserves, except for 200 Bcfe located within the northern portion of the Company's Pinedale Anticline leasehold in western Wyoming. Long-term development of natural gas reserves in the Pinedale Anticline Project Area (PAPA) 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 defined in the PAPA. The ROD contains additional requirements and restrictions on the sequence of development of the PAPA, which requires the Company to develop its leasehold from the south to the north. These restrictions result in protracted, phased development of the PAPA that is beyond the control of the Company. The Company has an ongoing development plan for the PAPA and the financial capability to continue development in the manner estimated.

As of December 31, 2012, all of the Company's oil and gas reserves are attributable to properties within the United Sates. A summary of the Company's change in quantities of proved oil and gas reserves for the years ended December 31, 2010, 2011 and 2012 are as follows:

	Natural Gas	Oil	NGL	Natural Gas Equivalents
	(Bcf)	(MMbbl)	(MMbbl)	(Bcfe)
Proved reserves				
Balance at December 31, 2009	2,525.0	29.3	7.7	2,746.9
Revisions of previous estimates	46.3	0.7	4.8	78.6
Extensions and discoveries	248.4	26.1	6.1	441.8
Purchase of reserves in place	0.2	—	—	0.2
Sale of reserves in place	(3.2)	(0.8)	—	(7.8)
Production	(203.8)	(3.0)	(1.2)	(229.0)
Balance at December 31, 2010	2,612.9	52.3	17.4	3,030.7
Revisions of previous estimates [4]	(270.1)	1.7	39.3	(23.5)
Extensions and discoveries [5]	641.9	17.4	22.6	881.6
Purchase of reserves in place	1.9	—	—	2.1
Sale of reserves in place	(0.8)	(0.2)	—	(1.9)
Production	(236.4)	(3.7)	(2.7)	(275.2)
Balance at December 31, 2011	2,749.4	67.5	76.6	3,613.8
Revisions of previous estimates [1]	**(240.6)**	**(1.5)**	**0.7**	**(244.8)**
Extensions and discoveries [2]	**330.6**	**17.3**	**23.0**	**572.5**
Purchase of reserves in place [3]	**32.3**	**42.0**	**4.9**	**313.8**
Sale of reserves in place	**—**	**—**	**—**	**—**
Production	**(249.3)**	**(6.3)**	**(5.3)**	**(319.2)**
Balance at December 31, 2012	**2,622.4**	**119.0**	**99.9**	**3,936.1**
Proved developed reserves				
Balance at December 31, 2009	1,178.7	22.4	4.9	1,342.8
Balance at December 31, 2010	1,404.8	25.1	9.3	1,611.5
Balance at December 31, 2011	1,538.3	33.0	38.4	1,966.3
Balance at December 31, 2012	**1,531.7**	**47.4**	**49.3**	**2,111.9**
Proved undeveloped reserves				
Balance at December 31, 2009	1,346.3	6.9	2.8	1,404.1
Balance at December 31, 2010	1,208.1	27.2	8.0	1,419.2
Balance at December 31, 2011	1,211.1	34.6	38.2	1,647.5
Balance at December 31, 2012	**1,090.7**	**71.6**	**50.6**	**1,824.2**

(1) Revisions of previous estimates in 2012 include negative impacts due to 152.4 Bcfe pricing revisions, 35.6 Bcfe performance revisions, 27.6 Bcfe operating cost revisions and 29.1 Bcfe other revisions. The 152.4 Bcfe pricing revisions were due to lower natural gas prices which reduced natural gas reserve volumes by 147.7 Bcf. Negative performance revisions were driven by a 56.0 Bcfe decrease in Pinedale reserves. Pinedale reserve adjustments are based on additional production history, well performance and current pricing causing a revised future development plan which includes lower density drilling in some flank areas, resulting in 25 proved undeveloped (PUD) locations being eliminated. Reserve decreases are partially offset by a 35.9 Bcfe positive impact from revisions in the Uinta Basin, due to the installation of the Iron Horse Cryogenic plant to increase liquid recoveries and improved well performance in the Red Wash Mesaverde field.

(2) Extensions and discoveries in 2012 increased proved reserves by 572.5 Bcfe, primarily related to extensions and discoveries in the Uinta Basin of 258.3 Bcfe, in Pinedale of 151.6 Bcfe, and 162.6 Bcfe in the Williston Basin,

Midcontinent and other Legacy areas of operation combined. 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.

(3) Purchase of reserves in place primarily relate to the Company's $1.4 billion 2012 Acquisition as discussed in Note 2 - Acquisition.

(4) Revisions of previous estimates in 2011 include 173.7 Bcfe negative impact due to performance revisions offset by 150.2 Bcfe positive impact from other revisions. The 173.7 Bcfe performance revisions were due to the reduction of natural gas volumes of 209.8 Bcf, partially offset by an increase in NGL volumes of 33.2 MMbbls, which is included in other revisions. The primary reason for the increase in the NGL volumes, or 31.8 MMbbls, relates to the completion of the Blacks Fork II plant and the fee-based processing agreement entered into between QEP Energy and QEP Field Services for QEP Energy's Pinedale production, offset by a reduction in the dry natural gas reserve related to shrink of about 59.6 Bcf. The remaining performance related reduction in the natural gas reserves was primarily related to the removal of certain PUD locations in the Haynesville/Cotton Valley area to recognize the 80-acre increased density development plan.

(5) Extensions and discoveries increased proved reserves by 881.6 Bcfe, primarily related to extensions and discoveries at the Haynesville/Cotton Valley area (358.8 Bcfe), Uinta Basin area (189.1 Bcfe) and Pinedale Anticline area (161.2 Bcfe). All of these extensions and discoveries related to new well completions and associated new PUD locations. Estimates of the quantity of proved reserves from the Company's Pinedale Anticline leasehold in western Wyoming have changed substantially over time as a result of numerous factors including, but not limited to, additional development drilling activity, producing well performance and the development and application of reliable technologies. The continued analysis of new data has led to progressive increases in estimates of original gas-in-place at Pinedale and to a better understanding of the appropriate well density to maximize the economic recovery of the in-place volumes. With the application of the amendments of ASC 932 in ASU 2010-03, reserves associated with Pinedale increased density drilling are included in extensions and discoveries for the years ended December 31, 2011 and 2010, because each new well drilled recovers incremental reserves that would otherwise be unrecoverable.

Standardized Measure of Future Net Cash Flows Relating to Proved Reserves

Future net cash flows were calculated at December 31, 2012, 2011 and 2010, by applying prices, which were the simple average of the first-of-the-month commodity prices, adjusted for location and quality differentials, for the 12-months of 2012, 2011 and 2010 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,		
	2012	2011	2010
Average benchmark price per unit:			
Natural gas price (per MMbtu)	**$ 2.76**	$ 4.12	$ 4.38
Crude oil price (per Bbl)	**94.71**	96.19	79.43

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 $1,042.5 million in 2013, $871.1 million in 2014 and $814.5 million in 2015.

The assumptions used to derive the standardized measure of 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 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 probably differ from those required to be used in these calculations.
- Future operating and capital costs will probably differ from those required to be used in these calculations.
- Future market conditions, government regulations and reservoir conditions 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 future net cash flows relating to proved reserves is presented in the table below:

	Year Ended December 31,		
	2012	2011	2010
		(in millions)	
Future cash inflows	**$ 18,200.2**	$ 18,300.6	$ 14,174.8
Future production costs	**(5,027.2)**	(4,276.1)	(3,701.8)
Future development costs	**(3,927.3)**	(3,250.0)	(2,275.9)
Future income tax expenses	**(2,269.0)**	(2,837.1)	(1,957.6)
Future net cash flows	**6,976.7**	7,937.4	6,239.5
10% annual discount for estimated timing of net cash flows	**(3,942.0)**	(4,411.8)	(3,533.9)
Standardized measure of discounted future net cash flows	**$ 3,034.7**	$ 3,525.6	$ 2,705.6

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

	Year Ended December 31,		
	2012	2011	2010
		(in millions)	
Balance at January 1,	**$ 3,525.6**	$ 2,705.6	$ 1,443.0
Sales of gas, oil and NGL produced during the period, net of production costs	**(892.3)**	(1,779.9)	(1,125.7)
Net change in sales prices and in production (lifting) costs related to future production	**(2,083.5)**	1,472.5	1,775.8
Net change due to extensions, discoveries and improved recovery	**948.5**	1,806.4	789.1
Net change due to revisions of quantity estimates	**(387.8)**	(48.2)	140.4
Changes due to purchases of reserves in place	**831.4**	0.1	0.2
Changes due to sales of reserves in place	**—**	(8.0)	(26.0)
Previously estimated development costs incurred during the period	**513.0**	533.6	434.2
Changes in estimated future development costs	**(209.3)**	(1,110.4)	(325.4)
Accretion of discount	**499.4**	355.4	170.9
Net change in income taxes	**273.6**	(411.4)	(582.4)
Other	**16.1**	9.9	11.5
Net change	**(490.9)**	820.0	1,262.6
Balance at December 31,	**$ 3,034.7**	$ 3,525.6	$ 2,705.6

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

As disclosed in the Company's Current Report on Form 8-K, filed with the SEC on November 17, 2011, and its Current Report on Form 8-K/A, filed with the SEC on February 28, 2012, the Company changed its independent registered public accountants effective for the fiscal year ended December 31, 2012.

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, 2012. Based on such evaluation, such officers have concluded that, as of December 31, 2012, 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 reports filed or submitted by the Company 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, 2012, 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, 2012, management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in *Internal Control—Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2012, based on those criteria. 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, 2012, which is included in the consolidated financial statements in Item 8 of Part II of this Annual Report on Form 10-K.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by Item 10 concerning QEP's directors and nominees for directors and other corporate governance matters will be presented in the Company's definitive Proxy Statement prepared for the solicitation of proxies in connection with the Company's annual Meeting of Stockholders to be held on May 24, 2013, which will be filed with the Securities and Exchange Commission no later than 120 days subsequent to December 31, 2012 (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 Business Ethics and Compliance Policy (Ethics Policy) that applies to all of its directors, officers (including its Chief Executive Officer and Chief Financial Officer) and employees. QEP has posted the Ethics Policy on its website, www.qepres.com. Any waiver of the Ethics Policy for executive officers must be approved only by the Company's Board of Directors. QEP will post on its website any amendments to or waivers of the Ethics Policy 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 ACCOUNTING 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. 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
2.1	Agreement and Plan of Merger dated as of May 18, 2010, between Questar Market Resources, Inc., a Utah corporation, and QEP Resources, Inc., a Delaware corporation. (Incorporated by reference to Exhibit No. 2.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 24, 2010.)
2.2	Separation and Distribution Agreement dated as of June 14, 2010, by and between Questar Corporation and QEP Resources, Inc. (Incorporated by reference to Exhibit No. 2.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
3.1	Certificate of Incorporation dated May 18, 2010. (Incorporated by reference to Exhibit No. 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, deemed effective February 14, 2013. (Incorporated by reference to Exhibit No. 3.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on February 15, 2013.)
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 No. 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	The Company's 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 Company's 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	The Company's 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 1, 2008.)
4.5	Officers' Certificate setting forth the terms of the Company's 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 1, 2008.)
4.6	The Company's 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 Company's 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 Company's 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 Company's 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 Registrant's 5.250% Notes due 2023). (Incorporated by reference to Exhibit No. 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 No. 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on August 25, 2011.)
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 No. 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on April 20, 2012.)
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 No. 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 No. 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 No. 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+	QEP Resources, Inc. Deferred Compensation Plan for Directors (Incorporated by reference to Exhibit No. 10.4 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
10.7+	Amended and Restated Employment Agreement dated June 15, 2010 by and between QEP Resources, Inc., Questar Corporation and Charles B. Stanley (Incorporated by reference to Exhibit No. 10.5 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
10.8+	Amended and Restated Employment Agreement dated June 15, 2010 by and between QEP Resources, Inc., Questar Corporation and Richard J. Doleshek (Incorporated by reference to Exhibit No. 10.6 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
10.9+	QEP Resources, Inc. Cash Incentive Plan, dated effective as of January 1, 2012. (Incorporated by reference to Appendix A to the Company's Proxy Statement on Schedule 14A filed with the Securities and Exchange Commission on April 3, 2012.)
10.10+	QEP Resources, Inc. 2010 Long-Term Stock Incentive Plan adopted June 12, 2010. (Incorporated by reference to Exhibit No. 10.9 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 16, 2010.)
10.11+	QEP Resources, Inc. Executive Severance Compensation Plan effective as of March 1, 2012. (Incorporated by reference to Exhibit No. 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 16, 2012.)
10.12+	QEP Resources, Inc. Amended Deferred Compensation Wrap Plan adopted January 28, 2013. (Incorporated by reference to Exhibit No. 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on January 31, 2013.)
10.13+	QEP Resources, Inc. Supplemental Executive Retirement Plan (Incorporated by reference to Exhibit No. 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 by the Amended Deferred Compensation Wrap Plan adopted January 28, 2013. (Incorporated by reference to Exhibit No. 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on January 31, 2013.)
10.14+	QEP Resources, Inc. Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to certain key executives. (Incorporated by reference to Exhibit No. 10.1. to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.15+	QEP Resources, Inc. Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to other officers and key employees. (Incorporated by reference to Exhibit No. 10.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.16+	QEP Resources, Inc. Form of Incentive Stock Option Agreement for incentive stock options granted to certain key executives. (Incorporated by reference to Exhibit No. 10.3. to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.17+	QEP Resources, Inc. Form of Incentive Stock Option Agreement for incentive stock options granted to other officers and key employees. (Incorporated by reference to Exhibit No. 10.4 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.18+	QEP Resources, Inc. Form of Restricted Stock Agreement for restricted stock granted to certain key executives. (Incorporated by reference to Exhibit No. 10.5 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.19+	QEP Resources, Inc. Form of Restricted Stock Agreement for restricted stock granted to other officers and key employees. (Incorporated by reference to Exhibit No. 10.6 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.20+	QEP Resources, Inc. Form of Restricted Stock Agreement for restricted stock granted to non-employee directors. (Incorporated by reference to Exhibit No. 10.7 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.21+	QEP Resources, Inc. Form of Phantom Stock Agreement for phantom stock granted to non-employee directors. (Incorporated by reference to Exhibit No. 10.8 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)
10.22+	QEP Resources, Inc. Form of Restricted Stock Units Agreement for restricted stock units granted to Mr. Keith O. Rattie. (Incorporated by reference to Exhibit No. 10.9 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on June 29, 2010.)

10.23	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. (Incorporate by reference to Exhibit No. 10.1 to the Company's Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on October 30, 2012.)
10.24	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. (Incorporate by reference to Exhibit No. 10.2 to the Company's Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on October 30, 2012.)
10.25	Stipulation and Agreement of Settlement, filed February 13, 2013, in the U.S. District Court for the Western District of Oklahoma. (Incorporated by reference to Exhibit No. 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on February 15, 2013.)
12.1*	Ratio of earnings to fixed charges.
16.1	Letter from Ernst & Young LLP to the Securities and Exchange Commission dated February 28, 2012 regarding change in Registrant's Certifying Accountant. (Incorporated by reference to Exhibit No. 16.1 to the Company's Current Report on Form 8-K/A filed with the Securities and Exchange Commission on February 28, 2012.)
21.1*	Subsidiaries of the Company.
23.1*	Consent of Independent Registered Public Accounting Firm. - PricewaterhouseCoopers LLP.
23.2*	Consent of Independent Registered Public Accounting Firm - Ernst & Young LLP.
23.3*	Consent of Independent Petroleum Engineers and Geologists - Ryder Scott Company, L.P.
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 and Treasurer, 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 and Treasurer, respectively, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Qualifications and Report of Independent Petroleum Engineers and Geologists - Ryder Scott Company, L.P.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

*Filed herewith
\+ 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, 2012				
Allowance for bad debts	**$ 1.7**	**$ 1.4**	**$ (0.3)**	**$ 2.8**
Year ended December 31, 2011				
Allowance for bad debts	2.3	0.2	(0.8)	1.7
Year ended December 31, 2010				
Allowance for bad debts	3.0	(0.3)	(0.4)	2.3

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 22, 2013.

QEP RESOURCES, INC.
(Registrant)

/s/ C. B. Stanley
C. 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 and on February 22, 2013.

/s/ C. B. Stanley C. B. Stanley	Chairman, President and Chief Executive Officer (Principal Executive Officer)
/s/ Richard J. Doleshek Richard J. Doleshek	Executive Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ Kendall K. Carbone Kendall K. Carbone	Vice President and Controller (Principal Accounting Officer)
*C. B. Stanley	Chairman of the Board; Director
*Keith O. Rattie	Director
*Phillips S. Baker, Jr.	Director
*L. Richard Flury	Director
*David Trice	Director
*Robert E. McKee III	Director
*M. W. Scoggins	Director

February 22, 2013

By /s/ C. B. Stanley
C. B. Stanley, Attorney in Fact

Exhibit 12.1

QEP Resources, Inc.
Ratio of Earnings to Fixed Charges

	Year Ended December 31,				
	2012	2011	2010	2009	2008
Earnings					
Income from continuing operations before income taxes and adjustment for income or loss from equity investees	**$ 198.5**	$ 422.0	$ 458.3	$ 330.3	$ 802.5
Add (deduct):					
Fixed charges	**128.7**	95.7	89.8	72.1	68.3
Distributed income from equity investees	**7.9**	7.9	2.4	1.1	0.5
Capitalized interest	**(3.4)**	(3.0)	(3.1)	—	(4.9)
Minority interest in pre-tax income of subsidiaries that have not incurred fixed charges	**(3.1)**	(3.2)	(2.9)	(2.6)	(9.0)
Total earnings	**$ 328.6**	$ 519.4	$ 544.5	$ 400.9	$ 857.4
Fixed Charges					
Interest expense	**$ 122.9**	$ 90.0	$ 84.4	$ 70.1	$ 61.7
Capitalized interest	**3.4**	3.0	3.1	—	4.9
Estimate of the interest within rental expense	**2.4**	2.7	2.3	2.0	1.7
Total Fixed Charges	**$ 128.7**	$ 95.7	$ 89.8	$ 72.1	$ 68.3
Ratio of Earnings to Fixed Charges	**2.6**	5.4	6.1	5.6	12.6

Exhibit 21.1

QEP Resources, Inc.
Subsidiaries of the Company

Name	State of Organization
QEP Energy Company [1]	Texas
QEP Field Services Company [1]	Utah
QEP Marketing Company [1]	Utah
Uintah Basin Field Services, LLC [5]	Delaware
Rendezvous Gas Services, LLC [3]	Wyoming
Three Rivers Gathering, LLC [4]	Delaware
Rendezvous Pipeline Company, LLC [2]	Colorado
Perry Land Management Company, LLC [2]	Oklahoma
Roden Participants, LTD [7]	Texas
Clear Creek Storage Company, LLC [6]	Utah

[1] 100% owned by QEP Resources, Inc.
[2] 100% owned by QEP Field Services Company
[3] 78% owned by QEP Field Services Company
[4] 50% owned by QEP Field Services Company
[5] 38% owned by QEP Field Services Company
[6] 100% owned by QEP Marketing Company
[7] 14% owned by QEP Energy Company

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 of QEP Resources, Inc. (No. 333-165805 and No. 333-179709), and to the incorporation by reference in the Registration Statements on Form S-8 of QEP Resources, Inc. (Nos. 333-167726 and 333-167727), of our report dated February 21, 2013, relating to the consolidated financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 21, 2013

Exhibit 23.2

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

1. Registration Statement (Form S-8 No. 333-167726) pertaining to the QEP Resources, Inc. Long-Term Stock Incentive Plan,

2. Registration Statement (Form S-8 No. 333-167727) pertaining to the QEP Resources, Inc. Employee Investment Plan,

3. Registration Statement (Form S-3 No. 333-165805) of Questar Market Resources, Inc. (predecessor of QEP Resources, Inc.) and in the related Prospectus

of our report dated February 24, 2012, with respect to the consolidated financial statements and schedule of QEP Resources, Inc. as of December 31, 2011 and for each of the two years in the period ended December 31, 2011 included in this Annual Report (Form 10-K) of QEP Resources, Inc. for the year ended December 31, 2012.

/s/ Ernst & Young LLP
Denver, Colorado
February 21, 2013

Exhibit 23.3

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580 FAX (303) 623-4258

621 SEVENTEENTH STREET SUITE 1550 DENVER, COLORADO 80293 TELEPHONE 303) 623-9147

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

As independent petroleum engineers, we hereby consent to the reference of our appraisal reports relating to the proved gas and oil reserves of QEP Energy Company in the Annual Report on Form 10-K of QEP Resources, Inc. as of the years ended December 31, 2007, 2008, 2009, 2010, 2011 and 2012 incorporated herein by reference into Registration Statement Nos. 333-165805 on Form S-3, 333-167726 and 333-167727 on Form S-8.

/S/Ryder Scott Company, L.P.

Ryder Scott Company, L.P.

Denver, Colorado
February 19, 2013

Exhibit 24

POWER OF ATTORNEY

We, the undersigned directors of QEP Resources, Inc., hereby severally constitute C. B. Stanley and Richard J. Doleshek, and each of them acting alone, our true and lawful attorneys, with full power to them and each of them to sign for us, and in our names in the capacities indicated below, the Annual Report on Form 10-K for 2012 and any and all amendments to be filed with the Securities and Exchange Commission by QEP Resources, Inc., hereby ratifying and confirming our signatures as they may be signed by the attorneys appointed herein to the Annual Report on Form 10-K for 2012 and any and all amendments to such Report.

Witness our hands on the respective dates set forth below.

Signature	Title	Date
/s/ C.B. Stanley C. B. Stanley	Chairman of the Board President and Chief Executive Officer	2/19/2013
/s/ Keith O. Rattie Keith O. Rattie	Director	2/19/2013
/s/ Phillip S. Baker Phillips S. Baker	Director	2/19/2013
/s/ L. Richard Flury L. Richard Flury	Director	2/19/2013
/s/ Robert E. McKee Robert E. McKee	Director	2/19/2013
/s/ M. W. Scoggins M. W. Scoggins	Director	2/19/2013
/s/ David A. Trice David A. Trice	Director	2/19/2013

Exhibit 31.1

CERTIFICATION

I, Charles B. Stanley, certify that:

1. I have reviewed this report of QEP Resources, Inc. on Form 10-K for the period ended December 31, 2012;

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

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

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

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

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

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

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

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

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

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

February 22, 2013

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

Exhibit 31.2

CERTIFICATION

I, Richard J. Doleshek, certify that:

1. I have reviewed this report of QEP Resources, Inc. on Form 10-K for the period ended December 31, 2012;

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

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

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

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

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

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

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

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

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

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

February 22, 2013

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

Exhibit 32.1

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

In connection with this report of QEP Resources, Inc. (the Company) on Form 10-K for the period ended December 31, 2012, as filed with the Securities and Exchange Commission on the date hereof (the Report), C. B. Stanley, Chairman, President and Chief Executive Officer of the Company, and Richard J. Doleshek, Executive Vice President, Chief Financial Officer and Treasurer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

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

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

QEP RESOURCES, INC.

February 22, 2013

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

February 22, 2013

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

Exhibit 99.1

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

FAX (303) 623-4258
621 SEVENTEENTH STREET SUITE 1550DENVER, COLORADO 80293 TELEPHONE (303) 623-9147

February 6, 2013

QEP Energy Company
1050 Seventeenth Street, Suite 500
Denver, Colorado 80265

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of QEP Energy Company (QEP) as of December 31, 2012. The subject properties are located in the states of Arkansas, Colorado, Kansas, Louisiana, Montana, New Mexico, North Dakota, Oklahoma, Texas, Utah and Wyoming. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on February 6, 2013 and presented herein, was prepared for public disclosure by QEP in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of QEP as of December 31, 2012.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2012, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
QEP Energy Company

As of December 31, 2012				
	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Remaining Reserves				
Oil/Condensate – Barrels	46,250,565	1,128,888	71,651,305	119,030,758
Plant Products – Barrels	43,292,465	6,041,237	50,599,590	99,933,292
Gas – MMCF	1,398,603	133,066	1,090,694	2,622,363
Income Data M$				
Future Gross Revenue	$7,658,435	$ 528,124	$8,643,218	$16,829,777
Deductions	2,221,642	199,179	5,163,230	7,584,051
Future Net Income (FNI)	$5,436,793	$ 328,945	$3,479,988	$ 9,245,726
Discounted FNI @ 10%	$3,078,268	$ 159,517	$ 783,862	$ 4,021,647

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

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

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion costs, development costs, and certain abandonment costs net of salvage. Other deductions are variable operating costs primarily resulting from salt water disposal charges. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist, nor does it include any adjustment for cash on hand or undistributed income. Future net income does not include depreciation, depletion and amortization effects nor any impairment conditions. Liquid hydrocarbon reserves account for approximately 68 percent and gas reserves account for the remaining 32 percent of total future gross revenue from proved reserves.

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

	Discounted Future Net Income M$ As of December 31, 2012
Discount Rate Percent	Total Proved
5	$5,783,873
9	$4,297,436
10	$4,021,647
15	$2,994,402
20	$2,335,780

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

Reserves Included in This Report

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

The various proved reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report. The proved developed non-producing reserves included herein consist of the shut-in and behind pipe categories.
No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

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

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

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

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

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

Estimates of Reserves

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

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

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

The proved reserves for the properties included herein were estimated by performance methods, the volumetric method, analogy, or a combination of methods. All of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis which utilized extrapolations of historical production data available through December 2012 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by QEP or obtained from public data sources and were considered sufficient for the purpose thereof.

Approximately 99 percent of the proved developed non-producing and undeveloped reserves included herein were estimated by analogy. Approximately 1 percent of the proved developed non-producing and undeveloped reserves were estimated by the volumetric method. The volumetric analysis utilized pertinent well data furnished to Ryder Scott by QEP or which we have obtained from public data sources that were available through December 2012. The data utilized from the analogues as well as well data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

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

QEP has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by QEP with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements.

Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by QEP. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

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

Future Production Rates

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

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

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

Hydrocarbon Prices

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

QEP furnished us with the above mentioned average prices in effect on December 31, 2012. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

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

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

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$94.71/Bbl	$77.12/Bbl
	NGLs	WTI Cushing	$94.71/Bbl	$31.30/Bbl
	Gas	Henry Hub	$2.76/MMBTU	$2.25/MCF

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

Costs

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

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

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with QEP's plans to develop these reserves as of December 31, 2012. The implementation of QEP's development plans as presented to us and incorporated herein is subject to the approval process adopted by QEP's management. As the result of our inquiries during the course of preparing this report, QEP has informed us that the development activities included herein have been subjected to and received the internal approvals required by QEP's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to QEP. Additionally, QEP has informed us that they are not aware of any legal, regulatory, political or economic obstacles that would significantly alter their plans.

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

Standards of Independence and Professional Qualification

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

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

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

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

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

Terms of Usage

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

QEP makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, QEP has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and/or S-8 of QEP of the references to our name as well as to the references to our third party report for QEP, which appears in the December 31, 2012 annual report on Form 10-K of QEP. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by QEP.

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

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

Very truly yours,

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

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

Approved:

\s\ James L. Baird
James L. Baird, P.E.
Colorado License No. 41521
Managing Senior Vice President

Professional Qualifications of Primary Technical Person

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

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

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

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