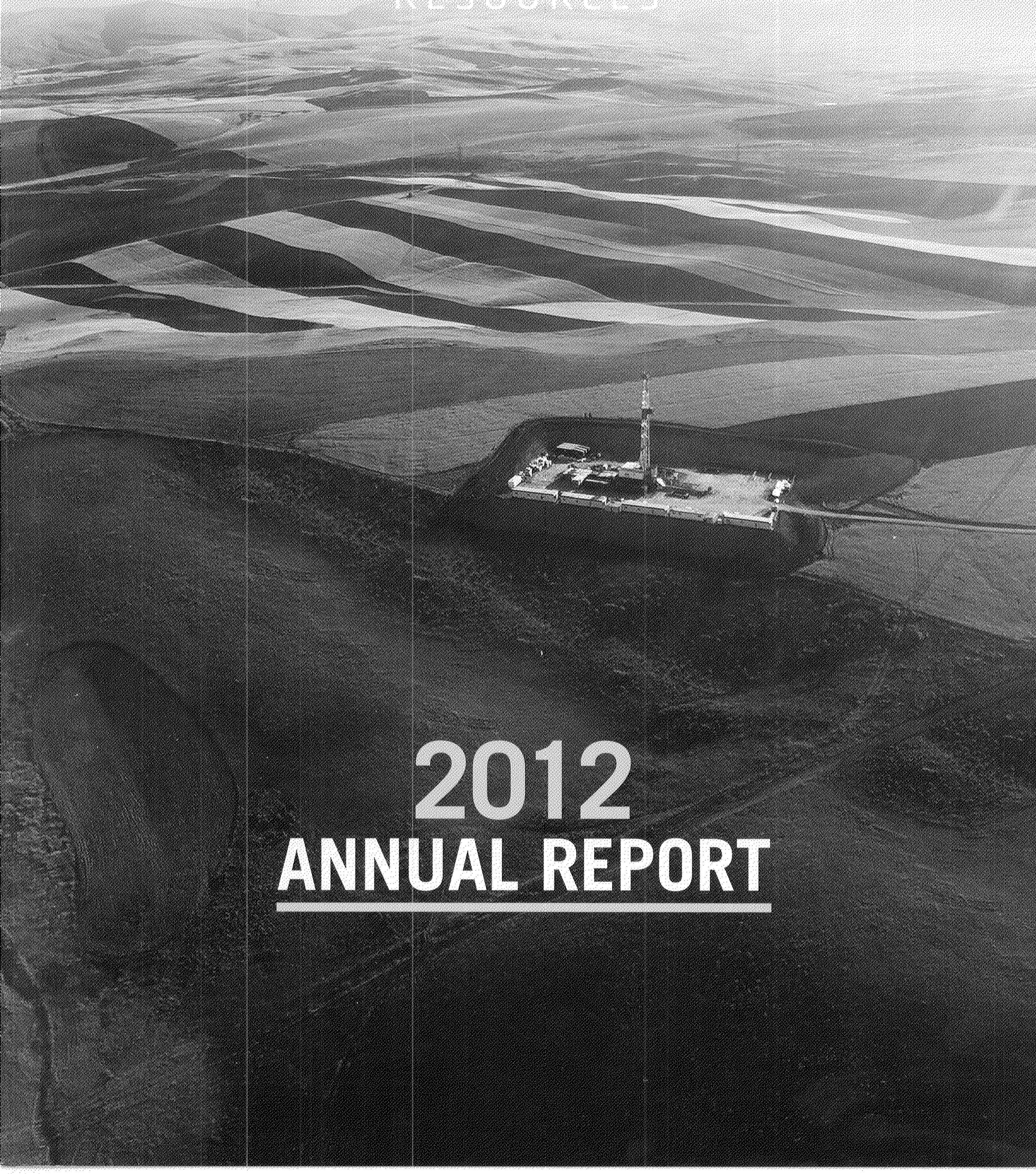
# QUICKSILVER
RESOURCES



# 2012 ANNUAL REPORT

# CORPORATEPROFILE

**QUICKSILVER RESOURCES INC.** is an independent exploration and production company focused on identifying, acquiring and developing natural gas and oil located onshore in North America. Based in Fort Worth, Texas, the company is widely recognized as a leader in the development and production of unconventional reservoirs including gas from shales and coal beds. The company's core developments are located in the Barnett Shale in the Fort Worth Basin in North Texas, the shales of the Horn River Basin in British Columbia, and the coals in Alberta. In addition, the company is pursuing high-potential exploratory opportunities in the Sand Wash Basin of northwestern Colorado and the Delaware and Midland basins of West Texas. The company also holds a substantial acreage position in the Southern Alberta Basin of western Montana.

As of December 31, 2012, the company has proved reserves of approximately 1.5 trillion cubic feet of natural gas equivalents, of which 76 percent is natural gas, 23% is NGL and 1% is crude oil and condensate; 88 percent are proved developed.

Quicksilver is a net asset value company focused on growth through the drill-bit by finding and developing long-lived unconventional natural gas and oil reservoirs at a low cost. The company has successfully and repeatedly executed on this strategy by acquiring acreage at the early stages of the life cycle, developing the resource into full development, and converting it to value to fund new projects.

The company's common shares are traded on the New York Stock Exchange under the ticker symbol KWK.

# TO OUR SHAREHOLDERS

**2013 MARKS THE 50TH YEAR THAT OUR FAMILY HAS BEEN IN THE OIL AND GAS BUSINESS. THE BUSINESS HAS CHANGED SIGNIFICANTLY OVER THIS PERIOD, AND WE HAVE WORKED HARD TO ANTICIPATE AND ADAPT. TO THAT END, WE HAVE MADE SIGNIFICANT STRIDES OVER THE PAST YEAR IN AN EFFORT TO DIVERSIFY OUR PORTFOLIO, RIGHT-SIZE THE BUSINESS, AND CREATE THE OPTIMAL COST STRUCTURE FOR THE NEW ECONOMIC REALITIES. DESPITE THESE CHANGES, WE CAN BE PROUD OF OUR SUCCESSES, OUR PEOPLE, AND OUR STRONG OPERATIONS. THESE VALUES ARE THE SAME VALUES THAT HAVE GUIDED OUR COMPANY SINCE ITS FOUNDING. IN 1963 OUR FATHER, FRANK DARDEN, FOUNDED QUICKSILVER'S PREDECESSOR COMPANY, MERCURY PRODUCTION COMPANY, AND BEGAN PUTTING DRILLING PROJECTS TOGETHER TO SELL TO OUTSIDE INVESTORS. MERCURY'S DRILLING ACTIVITY STARTED IN WEST CENTRAL TEXAS BUT OVER THE YEARS EXPANDED IN SCOPE SIGNIFICANTLY. MERCURY PROPERTIES AND AFFILIATED DARDEN FAMILY ENTITIES WERE COMBINED TO FORM QUICKSILVER RESOURCES IN 1998 AND THE COMPANY BEGAN ITS PUBLIC LIFE IN 1999 AFTER MERGING WITH MSR, A SMALL OIL COMPANY LISTED ON THE AMERICAN STOCK EXCHANGE. FOLLOWING A SIMILAR PATH THAT MERCURY CUT, QUICKSILVER WAS AN EARLY PIONEER IN THE DEVELOPMENT OF SHALE GAS RESOURCES.**

Over the past thirteen years as a public company Quicksilver has participated in a huge transformational event for our country and the world: the advent of producing large volumes of gas, and now oil, from shale. The benefits of finding and producing such large volumes of hydrocarbon will benefit the United States for decades. But this wave of new production has created excess supply, which has caused gas prices to plummet.

We began 2012 with natural gas prices at their lowest level in a decade. As the year progressed the price of associated natural gas liquids fell 50% in value. Although Quicksilver has been working hard to diversify its product mix, these two commodities – natural gas and natural gas liquids – comprise over 95% of our production.

Quicksilver has had success in two new oil projects, with our Niobrara play in northwest Colorado leading the charge. After drilling successful test wells, Quicksilver executed an agreement with Shell Western E&P to combine our respective acreage positions. This combination created a 320,000 net acre position within an Area of Mutual Interest of 850,000 acres. Quicksilver and Shell each own a 50% working interest, with Shell paying Quicksilver an equalization payment to balance the acreage contributions.

We also have begun producing oil from two initial test wells in west Texas. While this project is at an early stage, we believe we are on track for a sizeable development. The company has secured approximately 125,000 net acres across three blocks in this project. Following our company precedent, these projects have started from the "grass roots." Beginning with initial geologic and engineering ideas they are now moving to the commercial stage. This diversification to oil projects will not turn Quicksilver into an oil company; we have found too much natural gas to do that. Our objective is to diversify our business and create significant value that can bolster the company's cash flows and assist with debt reduction.

Quicksilver is in a position of needing to de-lever our balance sheet. This means selling parts of our large asset base to reduce outstanding debt. We have made recent progress on this objective and expect to report the results of additional efforts in the near future. In addition to selling assets, we have reduced capital spending, with the 2013 capital budget 70% lower than 2012's. Despite the reduced spending in 2013, we anticipate only single digit declines in year over year company production. Our operations remain strong, and we continue to employ some of the best talent in the industry. While we are making changes to enhance our financial position, our commitment to our operations and our people will not change.

This is reflected in some of our recent successes. As we have discussed previously Quicksilver has made a major gas discovery in the Horn River Basin in northwest British Columbia. This was confirmed in 2012 as the company brought online its first multi-well drilling pad. The eight wells on this pad tested at rates between 23 and 34 million cubic feet of gas per day per well, by far the best wells in company history. We have a world-class asset that must be connected to better markets. The federal and provincial governments of Canada are supporting aggressive plans to export natural gas from the Canadian west coast. With this encouragement and a compelling economic arbitrage to Asian markets, several LNG projects have been announced and permitted. This has sparked significant interest from countries and companies wanting to secure long-term gas supplies. We have been very active in discussing connecting our large resource with this increasing demand.

The current market for natural gas is a challenge. But we are tightening our belt and reducing costs across the board while maintaining excellence in safety and operational performance. We are taking steps to position the company for continued low gas prices. Quicksilver is protected on the gas pricing side with over 70% of our projected 2013 gas volumes hedged in excess of $5/Mcf. We are perhaps seeing a beginning of a flattening of the country's gas production due to reduced drilling. To this point any reduction in gas production has been delayed by companies drilling for oil and natural gas liquids and producing the associated gas. Lower NGL prices may slow the drilling even more in 2013. As a result we believe gas prices will improve as supply growth slows and industrial and power demand increases, but these price increases will not be large.

Our 2013 game plan is clear. Quicksilver expects to keep capital expenditures within operational cash flows and manage our current asset base to have single digit production declines. At the same time we will work to finish our asset sale and strategic transaction process in order to reduce debt. We will also push our new oil projects forward. Currently there are opportunities in the capital markets to re-finance a portion of our bonds at attractive rates, and we will work toward the best solution to give Quicksilver financial flexibility. We will also continue to pursue better downstream markets, both in Canada and the U.S., which can enhance long-term value for our products and our shareholders.

Very truly yours,

Glenn Darden
*Chief Executive Officer*

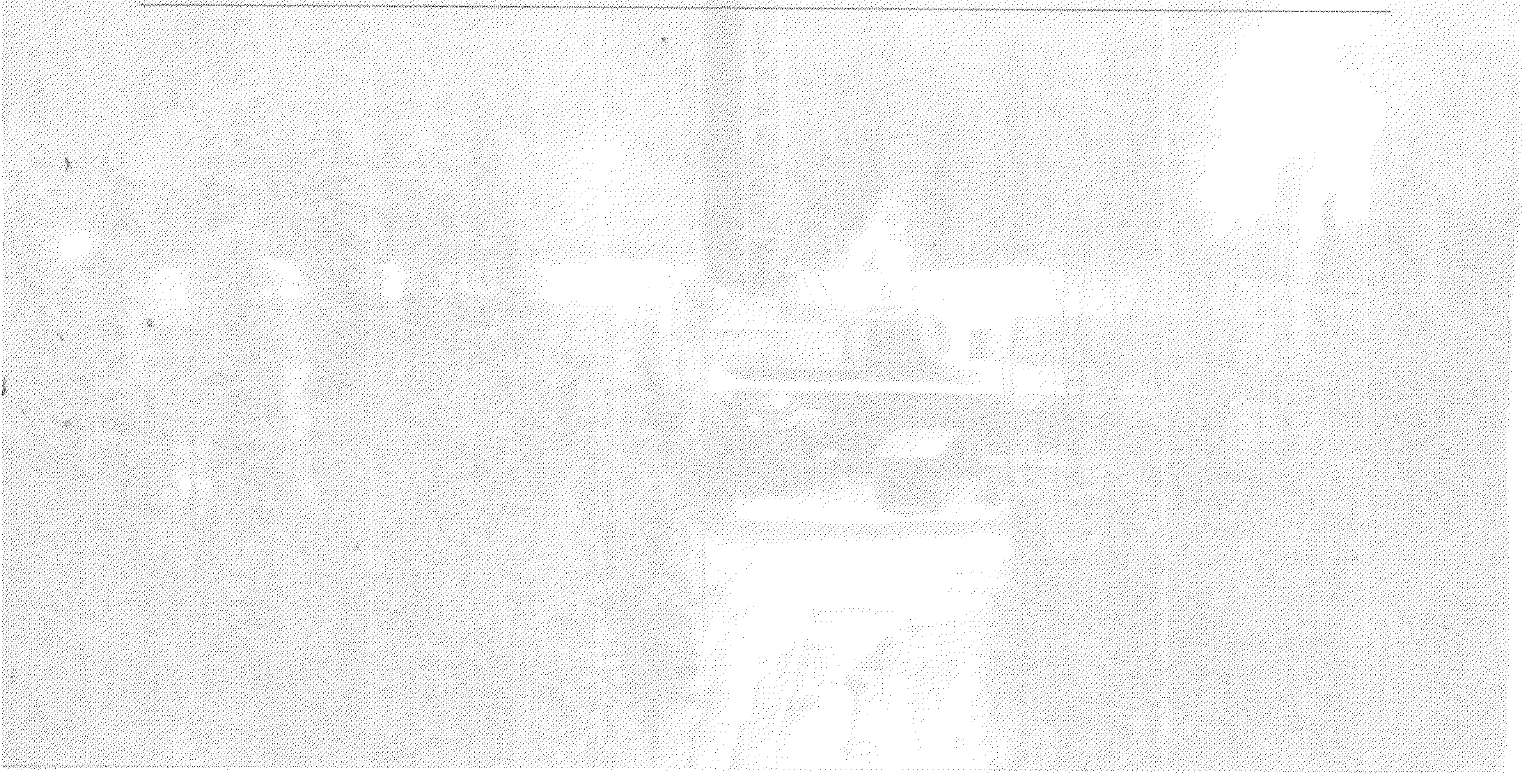
Thomas F. Darden
*Chairman*

# FINANCIAL HIGHLIGHTS

| In millions, except per share, production and product price data | 2012 | 2011 | 2010 | 2009 | 2008 |
|---|---|---|---|---|---|
| Total revenue | $ 709.0 | $ 943.6 | $ 928.3 | $ 832.7 | $ 800.6 |
| Reported net income (loss) attributable to Quicksilver [a] | $ (2,352.6) | $ 90.0 | $ 445.6 | $ (557.5) | $ (378.3) |
| Reported net income (loss) per diluted share [a] | $ (13.83) | $ 0.52 | $ 2.50 | $ (3.30) | $ (2.33) |
| Diluted weighted average number of shares outstanding for the periods [a] | 170.1 | 169.7 | 178.6 | 169.0 | 162.0 |
| Total assets | $ 1,381.8 | $ 3,995.5 | $ 3,507.7 | $ 3,612.9 | $ 4,498.2 |
| Long-term debt | $ 2,063.2 | $ 1,903.4 | $ 1,746.7 | $ 2,427.5 | $ 2,586.0 |
| Total equity | $ (1,132.8) | $ 1,261.9 | $ 1,069.9 | $ 696.8 | $ 1,211.6 |
| Natural gas production (Mmcf) | 105,591 | 122,228 | 101,664 | 86,039 | 68,128 |
| Average realized natural gas price per Mcf [b] | $ 4.21 | $ 4.95 | $ 6.86 | $ 7.42 | $ 8.10 |
| NGL production (Mmcfe) | 24,422 | 26,604 | 26,161 | 29,860 | 25,176 |
| Average realized NGL price per Mcfe [b] | $ 39.69 | $ 6.44 | $ 5.24 | $ 4.55 | $ 7.57 |
| Crude oil production (Mbbl) | 287 | 273 | 303 | 425 | 483 |
| Average realized price per Bbl [b] | $ 85.98 | $ 88.15 | $ 71.90 | $ 51.85 | $ 78.83 |

(a) Net loss and net loss per diluted share for 2012 include $1.8 billion and $10.58 per diluted share, respectively, associated with impairments of assets. Net income and net income per diluted share for 2011 include $142 million and $0.84 per diluted share, respectively, associated with gains on sales of BreitBurn Energy Partners L.P. (BBEP) units, and $70 million and $0.41 per diluted share, respectively, associated with impairments of assets. Net income attributable to Quicksilver and net income per diluted share for 2010 include $321 million and $1.80 per diluted share, respectively, associated with the sale of KGS. Net loss attributable to Quicksilver and net loss per diluted share for 2009 include approximately $722 million and $4.27 per diluted share, respectively, associated with impairment charges on U.S. and Canadian oil and gas properties and investment in BBEP. Net loss attributable to Quicksilver and net loss per diluted share for 2008 include approximately $620 million and $3.83 per diluted share, respectively, associated with impairment charges on U.S. oil and gas properties and investment in BBEP.

(b) Average realized prices reflect the effect of hedging transactions.



**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**

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to __________

Commission file number: **001-14837**



**QUICKSILVER RESOURCES INC.**
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Delaware** | **75-2756163** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| **801 Cherry Street, Suite 3700, Unit 19, Fort Worth, Texas** | **76102** |
| (Address of principal executive offices) | (Zip Code) |

**817-665-5000**
(Registrant's telephone number, including area code)

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 per share | New York Stock Exchange |
| Preferred Share Purchase Rights, $0.01 par value per share | 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 Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§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 the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

As of June 30, 2012, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $651,534,373 based on the closing sale price of $5.42 as reported on the New York Stock Exchange.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

| Class | Outstanding at February 28, 2013 |
|---|---|
| Common Stock, $0.01 par value per share | 176,568,548 shares |

**DOCUMENTS INCORPORATED BY REFERENCE**

| Document | Parts Into Which Incorporated |
|---|---|
| Proxy Statement for the Registrant's May 15, 2013 Annual Meeting of Stockholders | Part III |

## DEFINITIONS

As used in this Annual Report unless the context otherwise requires:

"**ABR**" means alternate base rate
"**AOCI**" means accumulated other comprehensive income
"**Bbl**" or "**Bbls**" means barrel or barrels
"**Bbld**" means barrel or barrels per day
"**Bcf**" means billion cubic feet
"**Bcfe**" means Bcf of natural gas equivalents
"**Boe**" means Bbl equivalents, calculated as six Mcf of gas equaling one bbl of oil
"**Canada**" means our oil and natural gas operations located principally in British Columbia and Alberta, Canada
"**C$**" means Canadian dollars
"**DD&A**" means Depletion, Depreciation and Accretion
"**GHG**" means greenhouse gas
"**GPT**" means gathering, processing and transportation expense
"**LIBOR**" means London Interbank Offered Rate
"**MBbl**" or "**MBbls**" means thousand barrels
"**MBoe**" means thousand Bbl of oil equivalent
"**MMBtu**" means million British Thermal Units, a measure of heating value, and is approximately equal to one Mcf of natural gas
"**Mcf**" means thousand cubic feet
"**Mcfe**" means Mcf natural gas equivalent, calculated as one Bbl of oil or NGLs equaling six Mcf of gas
"**MMcf**" means million cubic feet
"**MMcfd**" means million cubic feet per day
"**MMcfe**" means MMcf of natural gas equivalent
"**MMcfed**" means MMcfe per day
"**NGL**" or "**NGLs**" means natural gas liquids
"**NYMEX**" means New York Mercantile Exchange
"**OCI**" means other comprehensive income
"**Oil**" includes crude oil and condensate
"**PUD**" means proved undeveloped reserve
"**RSU**" means restricted stock unit
"**Tcfe**" means trillion cubic feet of natural gas equivalents

## COMMONLY USED TERMS

Other commonly used terms and abbreviations include:

"**2007 Senior Secured Credit Facility**" means collectively our U.S. senior secured revolving credit facility and our Canadian senior secured revolving credit facility, each dated as of February 9, 2007, which were terminated September 6, 2011 and replaced at that time by the Initial U.S. Credit Facility and the Initial Canadian Credit Facility
"**Alliance Acquisition**" means the 2008 purchase of natural gas leasehold, royalty interests and midstream assets in the Alliance airport area of the Barnett Shale
"**Alliance Asset**" means all of our natural gas leasehold and royalty interests in northern Tarrant and southern Denton counties
"**Amended and Restated Canadian Credit Facility**" means our new Canadian senior secured revolving credit facility which was amended and restated, effective December 22, 2011
"**Amended and Restated U.S. Credit Facility**" means our new U.S. senior secured revolving credit facility which was amended and restated, effective December 22, 2011
"**Barnett Shale Asset**" means our operations and our assets in the Barnett Shale located in the Fort Worth basin of North Texas
"**BBEP**" means BreitBurn Energy Partners L.P.
"**BBEP Unit**" means BBEP limited partner unit
"**CERCLA**" means the Comprehensive Environmental Response, Compensation and Liability Act
"**CMLP**" means Crestwood Midstream Partners LP
"**Combined Credit Agreements**" means collectively our Amended and Restated U.S. Credit Facility and our Amended and Restated Canadian Credit Facility
"**Crestwood**" means Crestwood Holdings LLC
"**Crestwood Transaction**" means the sale to Crestwood of all our interests in KGS, including general partner interests and incentive distribution rights

"**Eni**" means either or both Eni Petroleum US LLC and Eni US Operating Co. Inc., which are subsidiaries of Eni SpA
"**Eni Production**" means production attributable Eni's working and royalty interests
"**Eni Transaction**" means the 2009 conveyance to Eni of 27.5% of Quicksilver's interest in our Alliance Asset
"**EPA**" means the U.S. Environmental Protection Agency
"**FASB**" means the Financial Accounting Standards Board, which promulgates accounting standards in the U.S.
"**Fortune Creek**" means Fortune Creek Gathering and Processing Partnership, a midstream partnership formed with KKR in December 2011 dedicated to the construction and operation of natural gas midstream services within the Horn River basin of northeast British Columbia
"**GAAP**" means accounting principles generally accepted in the U.S.
"**Gas Purchase Commitment**" means the commitment pursuant to the Eni Transaction to purchase the Eni Production at a fixed price and which expired on December 31, 2010
"**HCDS**" means Hill County Dry System, a gas gathering system in Hill County, Texas within the Barnett Shale
"**Horn River Asset**" means our operations and our assets in the Horn River basin of northeast British Columbia
"**Horseshoe Canyon Asset**" means our operations and our assets in Horseshoe Canyon, the coalbed methane fields of southern and central Alberta
"**Initial Canadian Credit Facility**" means our initial Canadian senior secured revolving credit facility, dated as of September 6, 2011, which was amended and restated by the Amended and Restated Canadian Credit Facility on December 22, 2011
"**Initial U.S. Credit Facility**" means our initial U.S. senior secured revolving credit facility, dated as of September 6, 2011, which was amended and restated by the Amended and Restated U.S. Credit Facility on December 22, 2011
"**IRS**" means the U.S. Internal Revenue Service
"**KGS**" means Quicksilver Gas Services LP, a publicly-traded partnership, which we formerly owned that traded under the ticker symbol of "KGS" and subsequent to the Crestwood Transaction renamed itself Crestwood Midstream Partners LP and trades under the ticker symbol "CMLP"
"**KGS Secondary Offering**" means the public offering of 4,000,000 KGS common units in 2009 and the underwriters' purchase of an additional 549,200 KGS common units in 2010
"**KKR**" means Kohlberg Kravis Roberts & Co. L.P., with whom we formed Fortune Creek
"**Komie North Project**" means the series of contracts with NGTL for the construction of a pipeline and meter station, which will serve our and others' transportation needs in the Horn River basin
"**Lake Arlington Asset**" means our natural gas leasehold interests in the Lake Arlington area of the Barnett Shale
"**Mercury**" means Mercury Exploration Company, which is owned by members of the Darden family
"**NEB**" means National Energy Board, an independent agency which regulates international and interprovincial aspects of the oil and gas industries in Canada and is accountable to Parliament through the Minister of Natural Resources Canada.
"**NGTL**" means NOVA Gas Transmission Ltd., a subsidiary of TransCanada PipeLines Limited
"**Niobrara Asset**" means our operations and our assets in the Niobrara formation in northwest Colorado, which we are jointly developing with SWEPI LP
"**OSHA**" means Occupational Safety & Health Administration
"**SEC**" means the U.S. Securities and Exchange Commission
"**Southern Alberta Asset**" means our operations and our assets in the Southern Alberta basin of northern Wyoming and Montana, including our Cutbank field operations and assets
"**SWEPI**" means SWEPI LP, a subsidiary of Royal Dutch Shell plc
"**VIE**" means variable interest entity
"**West Texas Asset**" means our operations and our assets in the Midland and Delaware basins in West Texas prospective in the Bone Springs and Wolfcamp formations, principally concentrated in three areas: Jeff Davis and Reeves Counties, Upton and Crockett Counties and Pecos County

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**For the Year Ended December 31, 2012**



Except as otherwise specified and unless the context otherwise requires, references to the "Company," "Quicksilver," "we," "us," and "our" refer to Quicksilver Resources Inc. and its subsidiaries.

**Forward-Looking Information**

Certain statements contained in this Annual Report and other materials we file with the SEC, or in other written or oral statements made or to be made by us, other than statements of historical fact, are "forward-looking statements" as defined in the Private Securities Litigation Reform Act of 1995. Forward-looking statements give our current expectations or forecasts of future events. Words such as "may," "assume," "forecast," "position," "predict," "strategy," "expect," "intend," "plan," "estimate," "anticipate," "believe," "project," "budget," "potential," or "continue," and similar expressions are used to identify forward-looking statements. They can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed. Actual results may vary materially. You are cautioned not to place undue reliance on any forward-looking statements. You should also understand that it is not possible to predict or identify all such factors and should not consider the following list to be a complete statement of all potential risks and uncertainties. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

- changes in general economic conditions;
- fluctuations in natural gas, NGL and oil prices;
- failure or delays in achieving expected production from exploration and development projects;
- our ability to achieve anticipated cost savings and other spending reductions;
- uncertainties inherent in estimates of natural gas, NGL and oil reserves and predicting natural gas, NGL and oil production and reservoir performance;
- effects of hedging natural gas, NGL and oil prices;
- fluctuations in the value of certain of our assets and liabilities;
- competitive conditions in our industry;
- actions taken or non-performance by third parties, including suppliers, contractors, operators, processors, transporters, customers and counterparties;
- changes in the availability and cost of capital;
- delays in obtaining oilfield equipment and increases in drilling and other service costs;
- delays in construction of transportation pipelines and gathering, processing and treating facilities;
- operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- the effects of existing and future laws and governmental regulations, including environmental and climate change requirements;
- failure or delay in completing strategic transactions;
- the effects of existing or future litigation;
- failure or delays in completing Quicksilver's proposed initial public offering of common units representing limited partner interests in a master limited partnership holding portions of our Barnett Shale Asset; and
- additional factors described elsewhere in this Annual Report.

This list of factors is not exhaustive, and new factors may emerge or changes to these factors may occur that would impact our business. Additional information regarding these and other factors may be contained in our filings with the SEC, especially on Forms 10-K, 10-Q and 8-K. All such risk factors are difficult to predict, and are subject to material uncertainties that may affect actual results and may be beyond our control. The forward-looking statements included in this Annual Report are made only as of the date of this Annual Report, and we undertake no obligation to update any of these forward-looking statements to reflect subsequent events or circumstances except to the extent required by applicable law.

All forward-looking statements are expressly qualified in their entirety by the foregoing cautionary statements.

## PART I

### ITEM 1. Business

### GENERAL

We are an independent oil and gas company engaged primarily in the acquisition, exploration, development and production of onshore oil and gas in North America and are based in Fort Worth, Texas. We focus primarily on unconventional reservoirs where hydrocarbons may be found in challenging geological conditions, such as fractured shales and coalbeds. Our producing oil and gas properties in the United States are principally located in Texas, Colorado, Wyoming and Montana, and in Canada in Alberta and British Columbia. We had total proved reserves of approximately 1.5 Tcfe at December 31, 2012. Our three core areas include:

- Barnett Shale;
- Horn River; and
- Horseshoe Canyon.

In the Horn River basin, we are in transition from the exploratory phase to a developmental focus, particularly in the southern portion of our acreage. We also have significant oil exploration opportunities in North America, most notably in the following regions:

- Midland and Delaware basins in West Texas;
- Sand Wash Basin in northwest Colorado.

Our current exploration opportunities will provide growth in years to come and our new ventures team actively studies other basins in North America which, assuming favorable market conditions, may yield future exploration opportunities.

Our common stock trades under the symbol "KWK" on the New York Stock Exchange.

### FORMATION AND DEVELOPMENT OF BUSINESS

We were organized as a Delaware corporation in 1997 and became a public company in 1999. As of February 28, 2013, members of the Darden family and entities controlled by them beneficially owned approximately 30% of our outstanding common stock.

### STRATEGIC TRANSACTIONS IN THE LAST FIVE YEARS

On December 28, 2012, we entered into an agreement with SWEPI LP to jointly develop our oil and gas interests in the Niobrara formation of the Sand Wash Basin and to establish an Area of Mutual Interest ("AMI") covering in excess of 850,000 acres. Each party assigned to the other a 50% working interest in the majority of its combined acreage so that each party owns a 50% interest in more than 320,000 acres and has the right to a 50% interest in any acquisition within the AMI. SWEPI paid us an equalization payment for 50% of the acreage contributed by us in excess of the acreage that SWEPI contributed. SWEPI is the operator of the majority of the jointly owned lands. This relationship is strategic to the development of the Niobrara Asset as it created contiguous acreage blocks, which will lead to a more orderly and cost-effective development of the basin.

In February 2012, we filed a Form S-1 with the SEC to begin the registration and sale of limited partnership interests in a master limited partnership holding certain of our mature properties in our Barnett Shale Asset. We amended the registration statement in May to include financial statements for 2011 and to address comments received from the SEC and again in June to include financial statements for the first quarter of 2012 and to address further comments received from the SEC. In July 2012, we were informed that the SEC had no further comments. During the fourth quarter of 2012 we recognized an expense for the deferred filing fees associated with this offering since the transaction has been dormant since June 2012. This accounting treatment does not preclude us from updating the registration document at a later date and we will continue to monitor market conditions to assess the timing of an offering, which may be influenced by a joint venture covering our Barnett Shale Asset.

In December 2011, we and KKR formed a midstream partnership to construct and operate natural gas midstream services to support producer customers in British Columbia. We contributed to the partnership our existing 20-mile, 20-inch gathering line and compression facilities and 10-year contracts for gas deliveries into those facilities in consideration for $125 million and a 50% interest in the partnership. The creation of this partnership is strategic to the continued development of our Horn River Asset as it is expected to yield reduced costs for treating and transporting gas to sales markets.

In October 2010, we sold all of our interests in KGS, a Barnett Shale midstream subsidiary, to Crestwood. Crestwood paid $700 million in cash and assumed debt of $58 million and we recognized a gain of $494 million. In February 2012, we received an additional $41 million for consideration of an earn-out on these assets.

In May 2010, we acquired an additional 25% working interest in our Lake Arlington Asset which represented 125 Bcf of proved reserves, for $62 million in cash and 3.6 million BBEP Units. Throughout 2010 and 2011, through this and other transactions, we continued to sell our BBEP Units. We have owned no BBEP Units since 2011.

In January 2010, we completed the sale of certain of our midstream assets to KGS for $95 million. KGS funded the purchase primarily with proceeds from an equity offering to the public.

In June 2009, we completed the Eni Transaction in which we sold 121 Bcf of proved reserves to Eni for $280 million. Also as part of the Eni Transaction, we and Eni formed a strategic alliance for the acquisition and development of unconventional natural gas resources in an area covering approximately 270,000 acres surrounding our Alliance Asset.

In December 2008, we sold the gathering system in our Lake Arlington Asset to KGS for $42 million.

In August 2008, we completed the $1.3 billion Alliance Acquisition that consisted of producing and non-producing leasehold, royalty and midstream assets in the Barnett Shale. Consideration in the transaction was $1 billion in cash and $262 million of our common stock.

**BUSINESS STRATEGY**

We have a multi-pronged strategy to increase share value through long-term cost-effective growth in production and reserves by focusing on unconventional resource plays onshore in North America. This strategy takes advantage of our proven record and expertise in identifying and developing properties containing fractured shale and coalbed methane. Our strategy includes the following key elements:

*Strive to achieve and then to maintain a prudent capital structure to ensure financial flexibility:* We believe that a flexible financial structure would enable us to capitalize on opportunities and to limit our financial risk. Accordingly, in 2013 we intend to pursue the monetization of selected assets to improve our liquidity and to reduce our debt. We also expect to access the capital markets to begin extending the maturity of our senior notes. Our capital program has been reduced to the level of estimated cash inflows. We believe that these efforts will provide financial flexibility.

*Focus on core areas of repeatable, low-risk development:* We believe that development activity in areas where we have acquired a contiguous acreage position allows us to efficiently deploy our resources, manage our costs and leverage our technical expertise. Additionally, we search for new acreage positions that are not only contiguous from a surface perspective, which is more efficient for drilling, but are also contiguous from a resource perspective, which results in a more profitable asset when developed.

*Pursue disciplined organic growth opportunities:* We generally spend about 10% of our capital program on high-potential, longer cycle-time exploration projects to replenish our inventory of development projects for the future. Through our activities in multiple unconventional resource basins, we have established significant expertise and a demonstrated history of identifying, developing and producing fractured shales and coal beds. We are focused on identifying and evaluating additional opportunities that allow us to apply this expertise and experience to the development and operation of other unconventional reservoirs in North America.

We believe our core strength lies in our ability to identify and acquire large resource targets at low cost per acre. When we have secured an acreage position, we then drill resource assessment wells and validation wells to determine the size and commerciality of the project. Once the project is validated, we may build additional midstream infrastructure to secure affordable gathering, processing and transportation costs. Finally, we move the project to the full development stage. We have historically monetized some of our mature assets to provide financial flexibility to pursue future projects.

In order to increase the predictability of the prices we receive for our natural gas and NGL production, we hedge the commodity price of a substantial portion of our expected production with financial derivatives. We regularly review the credit-worthiness of our derivative counterparties, and our derivative program is spread among numerous financial institutions, all of whom participated in our credit facilities at the time of entering into the derivative. We have entered into long-term derivatives to provide predictability over longer periods.

**BUSINESS STRENGTHS**

*High-quality asset base with long reserve life:* Our proved reserves totaled approximately 1.5 Tcfe as of December 31, 2012, of which 88.0% were developed. Our Barnett Shale Asset accounts for approximately 81% of our proved reserves and approximately 18% are located in our Horseshoe Canyon Asset and our Horn River Asset. These areas have a history of proven well performance and have the established and emerging infrastructure necessary to deliver our production to sales markets. We believe our reserves are characterized by long lives and predictable well production profiles. Based on our annualized fourth quarter 2012 average production from all of our properties, our implied reserve life (proved reserves divided by annualized fourth quarter 2012 production) was 11.7 years and our implied proved developed reserve life (proved developed reserves divided by annualized fourth quarter 2012 production) was 10.3 years. As of December 31, 2012, almost 97% of our proved reserves were attributable to properties we operate.

*Multi-year inventory of developmental drilling projects:* As of December 31, 2012, we owned leases covering more than 569,000 net acres in our three core areas, of which 65% were classified as held by production. Within our Barnett Shale Asset alone, we have identified drilling locations that provide us greater than a 15-year inventory of drilling locations based on our three year historical drilling rate. Our drilling success rate has averaged more than 99% during the past three years. We use 3-D seismic data to enhance our ongoing drilling and development efforts as well as to identify new targets in both new and existing fields, and our seismic library covers more than 90% of our acreage in our Barnett Shale Asset.

We have also identified exploratory opportunities that provide meaningful exposure to additional oil and natural gas resources. As of December 31, 2012, we have successfully drilled and completed 12 gas wells in our Horn River Asset, and 98% of our licensed acreage has been validated. Our total proved reserves in our Horn River Asset are 105 Bcfe. We have also encountered oil in our Niobrara Asset across a 35-mile east-to-west line, and we have drilled two productive wells in our West Texas Asset.

*Extensive technical experience and familiarity with developing and operating Barnett Shale properties and other unconventional resources.* We are one of the larger producers in the Barnett Shale. The development of the Barnett Shale helped pioneer unconventional shale development, and the Barnett Shale currently produces over 6.2 Bcf of natural gas per day with over 16,000 wells drilled since 2003, according to the Railroad Commission of Texas. Our staff of petroleum professionals, many of whom have significant engineering, geologic and other expertise, allows us to be competitive in unconventional resource plays. We intend to utilize these resources to optimize our recovery of reserves and to enhance the value of our assets.

## FINANCIAL INFORMATION ABOUT SEGMENTS AND GEOGRAPHICAL AREAS

The consolidated financial statements included in Item 8 of this Annual Report contain information on our segments and geographical areas, are incorporated herein by reference.

## PROPERTIES

Substantially all of our properties consist of interests in developed and undeveloped oil and natural gas leases. In addition, we have gathering facilities in our Horn River Asset with KKR, with whom we formed Fortune Creek.

## OIL AND NATURAL GAS OPERATIONS

Our oil and natural gas operations are focused onshore in North America, in basins containing unconventional reservoirs with predictable, long-lived production. Our current production and development operations are concentrated in our three core areas: the Barnett Shale, Horn River, and Horseshoe Canyon. At December 31, 2012, we had total proved reserves of approximately 1.5 Tcfe, of which 76% is natural gas and 23% is NGLs. For 2012, we had total production of 132 Bcfe or 360 MMcfed. In the last five years, our reserves have declined at an approximate compound annual decline rate of 1%, and our production has grown at an approximate compound annual growth rate of 11%.

We believe the development of our leasehold interests in our core areas, and our exploration activities in our Niobrara Asset and West Texas Asset will give us the flexibility over the next several years to further grow reserves and production. Although not a part of our plans for 2013, we may also pursue acquisitions of additional interests where economically feasible, which could allow for further capitalization on our proven expertise in unconventional resource plays. Details of our 2013 capital program and our projected production levels can be found in Item 7 of this Annual Report.

### *Barnett Shale*

Over 81% of our total proved reserves and over 76% of our total average daily production in 2012 were in our Barnett Shale Asset. In the fourth quarter of 2012, our net production from our wells in our Barnett Shale Asset was 247.1 MMcfed. We expect approximately two-thirds of our 2013 production to come from our Barnett Shale Asset.

At December 31, 2012, we had approximately 127,000 net acres in the Barnett Shale of which approximately 60% is currently held by production. Much of our acreage in Hood and Somervell counties contains high-Btu natural gas. NGLs are extracted through midstream facilities that we constructed and are now owned by CMLP. In the current pricing environment, where NGLs trade at a premium to methane, we are able to increase our revenue per Mcf of natural gas production by extracting and separately selling NGLs. In 2012, sales of NGLs represented 24% of our Barnett Shale Asset production.

During 2012, we drilled 22 (20.5 net) wells and completed 45 (33.0 net) wells in our Barnett Shale Asset primarily from multi-well drilling pads. On these multi-well pads, all the wells are drilled prior to initiating completion activities. At December 31, 2012, we had drilled a total of 1,052 (879.9 net) wells in our Barnett Shale Asset since we began exploration and development operations in 2003. At December 31, 2012, we did not and currently do not have drilling rigs operating in our Barnett Shale Asset, but expect to utilize a rig in the basin in 2013 on a periodic basis.

***West Texas***

During 2012, we continued to build an oil prospective acreage position in the Bone Springs and Wolfcamp formations in the Midland and Delaware basins in West Texas. Our leases total 125,000 acres across Reeves, Pecos, Jeff Davis, Upton and Crockett Counties. We drilled and completed our first short-lateral well in Pecos County in August 2012, which targeted the Third Bone Springs formation, and we drilled and completed another short-lateral well in Upton County in December 2012, which targeted the Wolfcamp formation. Total proved reserves in our West Texas Asset are 0.6 Bcfe at December 31, 2012.

***Niobrara***

We hold approximately 167,000 primarily non-operated net acres in the Sand Wash basin, which we believe are prospective for oil from the Niobrara formation. We are currently conducting exploratory activities and have eight producing wells as of December 31, 2012. During 2012, we drilled and completed three vertical wells using a variety of stimulation methods and drilled one well. Jointly with SWEPI, we plan to participate in up to an additional eight wells in 2013, after which we plan to advance to the development stage, pending continued positive well results. Total proved reserves in our Niobrara Asset are 0.5 Bcfe at December 31, 2012.

***Horn River***

We hold approximately 129,000 net acres in our Horn River Asset. During August 2012, we completed an eight-well pad, with projected flow rates from each well between 23 MMcfd and 34 MMcfd at very high flowing pressures. We believe the results from these wells, the continuous nature of the pay sections as shown in 3-D seismic and the pay mapping from the six exploration wells drilled on the northern part of our acreage are indicative of the continuity of the formation throughout our acreage position.

As of December 31, 2012, we had eight wells producing and four wells capable of production that were temporarily shut-in. Production was curtailed from the new eight-well pad since August 2012 due to a delay in commissioning of a third-party's treating facility and due to limitations of surface equipment. In December 2012, we secured temporary alternative treating and transportation and increased gross production to 100 MMcfd within 15 days. We do not have a firm date for when the new treating facility, at which we have firm capacity, will be commissioned, but we believe we have sufficient treating and transportation capacity in the interim to meet our needs. Our total proved reserves in our Horn River Asset were 104.8 Bcfe as of December 31, 2012, all of which were natural gas and developed.

On January 30, 2013, the Canadian NEB issued its report recommending against approval of NGTL's Komie North Project, which included a 75-mile pipeline that would connect NGTL's Alberta system to a meter station planned to be constructed on our acreage in the Horn River Basin. We believe the NEB's recommendation against the Komie North Project will be adopted by the federal authority. The NEB concluded that the evidence presented at this time did not justify a 36-inch line as proposed; however, its recommendation notwithstanding, the NEB emphasized its belief in the long-term prospects for development of the Horn River Basin. We believe NGTL will undertake efforts to secure additional producer support for this pipeline.

The company had previously provided $30 million in letters of credit, which were reduced to $14 million during March 2013. We expect future financial assurances upon a revised application would be reduced proportionately relative to additional producer support. Also, we expect the application may be delayed by up to two years. Likewise, Quicksilver is planning to defer drilling in the Horn River Basin until 2014 and may recommend that Fortune Creek defer construction of a natural gas treating facility until at least 2016 to coincide with the revised timelines for the Komie North Project. Our agreements with NGTL will continue to require us to deliver up to 1 Tcf of production over a 10-year period and are expected to be amended to reflect the updated project time line. Our requirements may be reduced by delivery of volumes from third-party producers.

Our ability to sell gas at the Station 2 and AECO hubs has not been impacted by the NEB's recommendation, as our acreage is served by existing treating facilities and pipelines which today can accommodate in excess of 1 billion cubic feet per day. Due to the pace of development in the basin by all producers, discounted excess capacity is available in the region to meet Quicksilver's needs.

***Horseshoe Canyon***

At December 31, 2012, our Horseshoe Canyon Asset proved reserves were 162.0 Bcfe, substantially all of which was natural gas. As of December 31, 2012, we had 40,526 (30,116 net) undeveloped acres in our Horseshoe Canyon Asset. During 2012 we spent $0.7 million for drilling and completion in our Horseshoe Canyon Asset, largely funded by cash flows its from operations. No substantial drilling or completion activity is anticipated for 2013.

### *Rockies*

The Rockies area includes our Southern Alberta Asset which is located in the Cut Bank field in Montana. We have approximately 143,000 net acres in the Southern Alberta basin, 73% of which is held by production. At December 31, 2012, proved reserves from these properties were 15.5 Bcfe, of which 90% was oil or NGLs. Additionally, we hold assets within the Greater Green River Basin prospective for natural gas. We have approximately 39,514 net acres located in northwest Colorado and southern Wyoming. No proved reserves are currently recognized in this area.

## OIL AND NATURAL GAS RESERVES

Our proved reserve estimates and related disclosures for 2012, 2011 and 2010 are presented in compliance with SEC rules and regulations. The information with respect to our proved reserves and related disclosures has been prepared by Schlumberger PetroTechnical Services ("Schlumberger") and LaRoche Petroleum Consultants, Ltd. ("LaRoche"), our independent reserve engineers for U.S. and Canada, respectively.

The process of estimating our proved reserves is complex. In order to prepare these estimates, we have developed, maintained and monitored internal processes and controls for estimating and recording proved reserves in compliance with the rules and regulations of the SEC. Compliance with the SEC reserve guidelines is the primary responsibility of our reservoir engineering team. We require that proved reserve estimates be made by qualified reserve estimators, as defined by the Society of Petroleum Engineers' standards. Our reservoir engineering team, which is responsible for our proved reserve estimates, participates in continuing education to maintain a current understanding of SEC reserve reporting requirements.

Our reservoir engineering team, led by Chris Mundy, Vice President - Chief Reservoir Engineer, is responsible for the preparation and maintenance of our engineering data and review of our proved reserve estimates with Schlumberger and LaRoche. Mr. Mundy has over 15 years of experience in the oil and gas industry. Mr. Mundy is licensed as a Professional Engineer, registered with the Association of Professional Engineers, Geologists and Geophysicists of Alberta and is a member of the Society of Petroleum Engineers. Mr. Mundy earned a Bachelor of Applied Science degree in civil engineering from the University of Waterloo in Ontario, Canada. The reservoir engineering team reports directly to him and is otherwise independent from management for our operating areas. Throughout the year, the reservoir engineering team analyzes the performance of producing properties for each operating area, identifies proved reserve additions and revisions and prepares internal proved reserve estimates. In addition, the team is responsible for maintaining all reserve engineering data. Integrity of reserve engineering data is enhanced by restricting full access to only the members of our reservoir engineering team. Limited other personnel have read-only access with no ability to modify reserve engineering data.

The technical person at Schlumberger responsible for overseeing the preparation of our estimates of proved reserves is Charles M. Boyer II, PG, CPG. Mr. Boyer is licensed in the Commonwealth of Pennsylvania and has over 30 years of geologic and engineering experience in the oil and gas industry. Mr. Boyer earned a Bachelor of Science degree in geological sciences from The Pennsylvania State University in University Park and completed graduate studies in mining and petroleum engineering at the University of Pittsburgh and The Pennsylvania State University. The technical persons at LaRoche responsible for preparing our estimates of Canadian proved reserves meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. The technical person at LaRoche primarily responsible for overseeing the preparation of our estimates of proved reserves is Stephen W. Daniel. Mr. Daniel is a Professional Engineer licensed in the State of Texas who has over 40 years of engineering experience in the oil and gas industry. Mr. Daniel earned a Bachelor of Science degree in Petroleum Engineering from University of Texas and has prepared reserves estimates for his employers throughout his career. He has prepared and overseen preparation of reports for public filings for LaRoche for the past 16 years. Prior to finalizing their proved reserve estimates, each of Schlumberger's and LaRoche's results are reviewed in detail by internal reservoir engineering teams, Mr. Mundy and the other members of our executive management team.

The Audit Committee of our Board has met with our executive management team, including Mr. Mundy, and with Schlumberger and LaRoche to discuss the process and results of proved reserve estimation. The analytical review of proved reserve estimates includes comparisons of ending proved undeveloped estimates to our average ending ultimate recoverable proved reserves for each of our operating areas. Additional reviews of drilling results and proved undeveloped estimates have been conducted with our executive management team and the Audit Committee of our Board.

Pursuant to the rules and regulations of the SEC, proved reserves are the estimated quantities of natural gas, NGLs and oil which, through analysis of geological and engineering data, demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic conditions, operating methods and government regulations. The term "reasonable certainty" connotes a high degree of confidence that the quantities of natural gas, NGLs and oil actually recovered will equal or exceed the estimate. To achieve reasonable certainty, the technologies used in the estimation process must have been demonstrated to yield results with consistency and repeatability. Proved developed reserves are expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are expected to be recovered from new wells on undrilled acreage. Proved reserves for undrilled wells are estimated only where it can be demonstrated that there is continuity of production from the existing productive formation. To achieve reasonable certainty of our proved reserve estimates, our reservoir engineering team assumes continued use of technologies with demonstrated success of yielding expected results, including the use of drilling results, well performance, well logs, seismic data, geologic maps, well stimulation techniques, well test data, and reservoir simulation modeling.

The proved reserve data we disclose are estimates and are subject to inherent uncertainties. The determination of our proved reserves is based on estimates that are highly complex and interpretive. Reserve engineering is a subjective process that depends upon the quality of available data and on engineering and geological interpretation and judgment. Although we believe our proved reserve estimates are reasonable, reserve estimates are imprecise and are expected to change as additional information becomes available. Additional information regarding risks associated with estimating our proved reserves may be found in Item 1A of this Annual Report.

The following table summarizes our proved reserves.

| | Proved Developed Reserves | | | Proved Undeveloped Reserves | | | Total Proved Reserves | | |
|---|---|---|---|---|---|---|---|---|---|
| | For the Years Ended December 31, | | | For the Years Ended December 31, | | | For the Years Ended December 31, | | |
| | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 |
| Natural gas (MMcf) | | | | | | | | | |
| U.S. | 725,361 | 1,244,187 | 1,312,777 | 122,687 | 584,717 | 628,946 | 848,048 | 1,828,904 | 1,941,723 |
| Canada | 266,783 | 299,371 | 242,941 | — | 31,260 | 22,947 | 266,783 | 330,631 | 265,888 |
| Total | 992,144 | 1,543,558 | 1,555,718 | 122,687 | 615,977 | 651,893 | 1,114,831 | 2,159,535 | 2,207,611 |
| NGL (MBbl) | | | | | | | | | |
| U.S. | 47,284 | 60,902 | 64,908 | 8,890 | 41,243 | 47,536 | 56,174 | 102,145 | 112,444 |
| Canada | 10 | 11 | 12 | — | — | — | 10 | 11 | 12 |
| Total | 47,294 | 60,913 | 64,920 | 8,890 | 41,243 | 47,536 | 56,184 | 102,156 | 112,456 |
| Oil (MBbl) | | | | | | | | | |
| U.S. | 2,416 | 2,545 | 2,775 | 113 | 490 | 533 | 2,529 | 3,035 | 3,308 |
| Canada | — | — | — | — | — | — | — | — | — |
| Total | 2,416 | 2,545 | 2,775 | 113 | 490 | 533 | 2,529 | 3,035 | 3,308 |
| Total (MMcfe) | | | | | | | | | |
| U.S. | 1,023,562 | 1,624,866 | 1,718,875 | 176,703 | 835,118 | 917,357 | 1,200,265 | 2,459,984 | 2,636,232 |
| Canada | 266,845 | 299,437 | 243,017 | — | 31,260 | 22,947 | 266,845 | 330,697 | 265,964 |
| Total | 1,290,407 | 1,924,303 | 1,961,892 | 176,703 | 866,378 | 940,304 | 1,467,110 | 2,790,681 | 2,902,196 |

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| Representative prices for reserve estimation purposes: | | | |
| Natural gas – Henry Hub, per MMBtu | $ 2.76 | $ 4.12 | $ 4.38 |
| Natural gas – AECO, per MMBtu | 2.35 | 3.65 | 4.08 |
| Oil – WTI Cushing, per Bbl | 94.71 | 95.71 | 79.43 |
| Standardized measure of discounted future net cash flows [(1)] (in millions) | $ 715.1 | $ 1,734.9 | $ 1,786.4 |

(1) Determined based on year-end unescalated costs in accordance with the guidelines of the SEC, discounted at 10% per annum, net of tax.

The reference price used for our NGLs was based on WTI Cushing, adjusted for local differentials, gravity and BTU.

## PROVED UNDEVELOPED RESERVES

Our 2012 drilling and completion activities related to our proved undeveloped locations as of December 31, 2011 were as follows:

| | For the Year Ended December 31, 2012 | | | | | |
|---|---|---|---|---|---|---|
| | Drilled | | Completed | | Producing | |
| | Gross | Net | Gross | Net | Gross | Net |
| Barnett Shale | 19.0 | 17.5 | 13.0 | 11.8 | 13.0 | 11.8 |
| Horn River | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| Total | 21.0 | 19.5 | 15.0 | 13.8 | 15.0 | 13.8 |

Costs incurred in 2012 relating to the drilling and completion activities related to our proved undeveloped locations as of December 31, 2011 were $61.9 million.

Our gross capital costs for a Barnett Shale Asset well from preparation of the multi-well drilling pad through the initiation of production have an estimated median of $2.5 million depending on factors such as the area, the depth and lateral length of each well, number of stages of fracture stimulation and its distance to central facilities. On each multi-well drilling pad, we drill all the wells prior to initiation of completion activities. As a result, we maintain an inventory of drilled wells awaiting completion.

The following table summarizes our proved undeveloped reserves activity during the year ended December 31, 2012 (in Mmcfe):

| | |
|---|---|
| Beginning proved undeveloped reserves | 866,378 |
| Extensions and discoveries | 42,518 |
| Transfers to proved developed | (96,263) |
| Revisions of previous estimates | (635,930) |
| Ending proved undeveloped reserves | 176,703 |

Proved undeveloped reserves decreased approximately 580 Mmcfe primarily because we reduced our multi-year drilling program as a result of economic conditions, which introduced the effects of the five-year limitation on undeveloped wells primarily in our Barnett Shale Asset. Transfers to proved developed reserves of 73 Bcfe and 23 Bcfe occurred in our Barnett Shale Asset and Horn River Asset, respectively.

As of December 31, 2012, we had total proved undeveloped reserves of 176.7 Bcfe in our Barnett Shale Asset on 60 well locations, all of which are scheduled for development before the end of 2017.

We estimate that our proved undeveloped well locations will be developed on the following timeline:

| | |
|---|---|
| 2013 | 5 |
| 2014 | 34 |
| 2015 | 13 |
| 2016 | 5 |
| 2017 | 3 |
| Total | 60 |

During 2013, we expect to spend $6.5 million to drill, complete and tie-in wells on proved locations. Estimated future development costs on proved locations as of December 31, 2012 are projected to be $82.2 million for 2014, $38.5 million for 2015, $17.3 million for 2016, and $12.4 million for 2017.

At December 31, 2012, none of our inventory of proved undeveloped drilling locations has been recognized as proved reserves for five years or longer.

## DEVELOPMENT AND EXPLORATION ACTIVITIES AT YEAR END

At December 31, 2012, we had no drilling rigs operating in our Barnett Shale Asset and no completion work was in progress. In the U.S. we had 29 (27.2 net) wells awaiting completion or tie-in to sales lines.

No drilling rigs were operating in our Horn River Asset at December 31, 2012. There are currently 6 (6.0 net) wells drilled and awaiting completion that have no proved reserves assigned. These wells were drilled to preserve acreage and will not be completed until the gathering infrastructure is extended into these areas. Additionally, 129 (100.3 net) wells in our Horseshoe Canyon Asset were awaiting completion or tie-in to sales lines at December 31, 2012. The remaining wells in our Horseshoe Canyon Asset were drilled on leases set to expire in the near term and have not been completed pending resolution of potential title defects.

## DRILLING ACTIVITY

During the periods indicated, we drilled the following exploratory and development wells:

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2012 | | 2011 | | 2010 | |
| | Gross | Net | Gross | Net | Gross | Net |
| **Development:** | | | | | | |
| U.S. | | | | | | |
| Productive [1] | 22 | 20.5 | 61 | 49.6 | 97 | 80.5 |
| Non-productive | — | — | — | — | 2 | 1.5 |
| Canada | | | | | | |
| Productive [2] | 2 | 2.0 | 18 | 14.9 | 18 | 9.9 |
| Non-productive | — | — | — | — | — | — |
| Total | 24 | 22.5 | 79 | 64.5 | 117 | 91.9 |
| **Exploratory:** | | | | | | |
| U.S. | | | | | | |
| Productive | 8 | 5.7 | 8 | 6.0 | — | — |
| Non-productive | — | — | — | — | — | — |
| Canada | | | | | | |
| Productive | 2 | 2.0 | 4 | 4.0 | 2 | 2.0 |
| Non-productive | — | — | — | — | — | — |
| Total | 10 | 7.7 | 12 | 10.0 | 2 | 2.0 |
| **Total:** | | | | | | |
| Productive | 34 | 30.2 | 91 | 74.5 | 117 | 92.4 |
| Non-productive | — | — | — | — | 2 | 1.5 |
| Total | 34 | 30.2 | 91 | 74.5 | 119 | 93.9 |

(1) U.S. development drilling includes non-operated drilling of 2 wells (0.0 net), 4 wells (0.0 net) and 3 wells (0.4 net) for 2012, 2011 and 2010, respectively.

(2) Canadian development drilling includes non-operated drilling of 2 wells (1.0 net) and 7 wells (0.4 net) for 2011 and 2010, respectively.

## VOLUME, SALES PRICES AND OIL AND GAS PRODUCTION EXPENSE

The discussion of volume produced from, revenue generated by and cost associated with operating our properties included in Management's Discussion and Analysis in Item 7 of this Annual Report is incorporated herein by reference.

## DELIVERY COMMITMENTS AND PURCHASERS OF NATURAL GAS, NGLs AND OIL

We have contracts with third parties that require we provide minimum daily natural gas or NGL volume for gathering, fractionation and transportation, as determined on a monthly basis, or pay for any deficiencies at a specified reservation fee rate. We will utilize production volumes from our wells plus royalty volumes we control and other third-party volumes towards meeting our commitments below. We will fund any shortfall with cash which could be between $5 million and $10 million in 2013 depending on the timing of the commissioning of the third-party gas treating facility and our production levels.

Our prospective obligations under existing agreements are summarized below:

| | Total | 2013 | 2014 | 2015 | 2016 | 2017 | Thereafter |
|---|---|---|---|---|---|---|---|
| | | | | (In Mmcfe) | | | |
| Gathering | | | | | | | |
| Barnett Shale | 29,650 | 9,125 | 9,125 | 9,125 | 2,275 | — | — |
| Horn River | 1,066,728 | 73,427 | 77,491 | 73,545 | 163,416 | 162,970 | 515,879 |
| Processing, Treating and Fractionation | | | | | | | |
| Barnett Shale | 39,420 | 39,420 | — | — | — | — | — |
| Horn River | 194,460 | 34,000 | 37,045 | 37,045 | 37,146 | 37,045 | 12,179 |
| Transportation | | | | | | | |
| Barnett Shale | 465,737 | 102,507 | 82,467 | 80,607 | 73,813 | 71,296 | 55,047 |
| Horseshoe Canyon | 16,608 | 11,996 | 3,861 | 738 | 13 | — | — |
| Horn River | 1,104,297 | 16,315 | 19,862 | 35,177 | 56,553 | 41,265 | 935,125 |

We have dedicated substantially all natural gas production from our Barnett Shale Asset for gathering and compression to CMLP through 2020. The rates charged by CMLP are fixed for each system but vary by system and range from $0.71 to $0.87 per Mcf of gathered volume, subject to annual inflationary increases. Processing fees are fixed at $0.70 per Mcf, and are also subject to annual inflationary increases. We are not obligated to guarantee CMLP any minimum volume (accordingly the above table of commitments does not include amounts which flow to CMLP).

We sell natural gas, NGLs and oil to a variety of customers, including utilities, major oil and natural gas companies or their affiliates, industrial companies, large trading and energy marketing companies and other users of petroleum products. Because our products are commodity products sold primarily on the basis of price and availability, we are not dependent upon one purchaser or a small group of purchasers. Accordingly, the loss of any single purchaser would not materially affect our revenue. During 2012, Targa Liquids Marketing and Trade and Lone Star NGL Product Services LLC, the largest purchasers of our production, accounted for 21% and 15%, respectively, of our cash collected for natural gas, NGL and oil sales.

## ACQUISITION, EXPLORATION AND DEVELOPMENT CAPITAL EXPENDITURES

The following table summarizes our acquisition, exploration and development costs incurred:

| | U.S. | Canada | Consolidated |
|---|---|---|---|
| | | (In thousands) | |
| **2012** | | | |
| Proved acreage | $ — | $ — | $ — |
| Unproved acreage | 23,711 | 5,612 | 29,323 |
| Development costs | 131,926 | 178,808 | 310,734 |
| Exploration costs | 35,244 | 8,304 | 43,548 |
| Total | $ 190,881 | $ 192,724 | $ 383,605 |
| **2011** | | | |
| Proved acreage | $ — | $ — | $ — |
| Unproved acreage | 145,099 | — | 145,099 |
| Development costs | 304,373 | 90,361 | 394,734 |
| Exploration costs | 37,673 | 41,338 | 79,011 |
| Total | $ 487,145 | $ 131,699 | $ 618,844 |
| **2010** | | | |
| Proved acreage | $ 125,647 | $ 19,271 | $ 144,918 |
| Unproved acreage | 44,271 | 827 | 45,098 |
| Development costs | 378,056 | 14,182 | 392,238 |
| Exploration costs | 9,385 | 57,896 | 67,281 |
| Total | $ 557,359 | $ 92,176 | $ 649,535 |

## PRODUCTIVE OIL AND GAS WELLS

The following table summarizes productive wells:

| | As of December 31, 2012 | | | |
|---|---|---|---|---|
| | Natural Gas | | Oil | |
| | Gross | Net | Gross | Net |
| U.S. | 1,031 | 839.2 | 220 | 210.9 |
| Canada | 2,884 | 1,411.1 | 4 | 1.1 |
| Total | 3,915 | 2,250.3 | 224 | 212.0 |

## OIL AND GAS ACREAGE

Our principal oil and gas properties consist of non-producing and producing oil and gas leases and mineral acreage, including reserves of natural gas and oil in place. Developed acres are defined as acreage allocated to wells that are producing or capable of producing. Undeveloped acres are acres on which wells are not to a point that would permit the production of commercial reserves or acreage which has not yet been allocated to any wells, regardless of whether such acreage contains proved reserves. Gross acres are the total number of acres in which we have a working interest. Net acres are the sum of our fractional interests owned in the gross acres.

The following table indicates our interest in developed and undeveloped acreage:

| | As of December 31, 2012 | | | |
|---|---|---|---|---|
| | Developed Acreage | | Undeveloped Acreage | |
| | Gross | Net | Gross | Net |
| Barnett Shale | 86,188 | 76,109 | 69,365 | 50,982 |
| West Texas (1) | 2,712 | 2,513 | 216,621 | 162,699 |
| Niobrara | 6,259 | 2,327 | 449,666 | 164,691 |
| Other U.S. | 120,264 | 109,370 | 114,046 | 91,958 |
| U.S. | 215,423 | 190,319 | 849,698 | 470,330 |
| Horseshoe Canyon | 459,721 | 282,728 | 40,526 | 30,116 |
| Horn River Basin | 12,864 | 12,246 | 127,556 | 116,863 |
| Canada | 472,585 | 294,974 | 168,082 | 146,979 |
| Total | 688,008 | 485,293 | 1,017,780 | 617,309 |

(1) Includes 77,194 gross (41,115 net) undeveloped acres located in Presidio County which we believe is not prospective for the Bone Springs or Wolfcamp formations.

The following table summarizes information regarding the total number of net undeveloped acres as of December 31, 2012:

| | | 2013 Expirations | | 2014 Expirations | | 2015 Expirations | |
|---|---|---|---|---|---|---|---|
| | Net Undeveloped Acres | Net Acres | Net Acres with Options to Extend | Net Acres | Net Acres with Options to Extend | Net Acres | Net Acres with Options to Extend |
| Barnett Shale | 50,982 | 7,502 | 102 | 5,899 | 426 | 5,237 | 523 |
| West Texas | 162,699 | 5,459 | — | 64,325 | 38,598 | 48,702 | 4,516 |
| Niobrara | 164,691 | 60,157 | 15,776 | 38,718 | 28,429 | 24,010 | 5,669 |
| Other U.S. | 91,958 | 12,723 | — | 15,036 | — | 3,352 | — |
| Canada | 146,979 | 6,997 | 386 | 4,258 | — | 3,063 | — |
| Total | 617,309 | 92,838 | 16,264 | 128,236 | 67,453 | 84,364 | 10,708 |

All of the acreage scheduled to expire can be held through drilling and producing operations. We believe that we have the ability to retain substantially all of the expiring acreage that we believe will provide economic returns either through drilling activities or through the exercise of extension options.

## COMPETITION

We compete for acquisitions of prospective oil and natural gas properties and oil and gas reserves. We also compete for drilling rigs and equipment used to drill for and produce oil and gas. Our competitive position is dependent upon our ability to recruit and retain geological, engineering and management expertise. We believe that the location of our leasehold acreage, our exploration and production expertise and the experience and knowledge of our management team enable us to compete effectively in our core operating areas. However, we face competition from a substantial number of other companies, many of which have larger technical staffs and greater financial and operational resources than we do and from companies in other, but potentially related, industries.

## GOVERNMENTAL REGULATION

Our operations are affected from time to time in varying degrees by political developments and U.S. and Canadian federal, state, provincial and local laws and regulations. In particular, our production and related operations are, or have been, subject to taxes and other laws and regulations relating to the industry. Failure to comply with such laws and regulations can result in substantial penalties and delayed operations. The regulatory burden on the industry increases our cost of doing business and affects our profitability. We do not anticipate any significant challenges in complying with laws and regulations applicable to our operations.

## SAFETY REGULATION

We are subject to a number of federal, state, provincial and local laws and regulations, whose purpose is to protect the health and safety of workers, both generally and within our industry. Regulations overseen by OSHA, the EPA, Human Resources and Skills Development Canada, Environment Canada and other agencies require, among other matters, that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We are also subject to safety regulations which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals.

## ENVIRONMENTAL MATTERS

We are subject to stringent and complex federal, state, provincial and local environmental laws, regulations and permits, including those relating to the generation, storage, handling, use, disposal, gathering, transmission and remediation of natural gas, NGLs, oil and hazardous materials; the emission and discharge of such materials to the ground, air and water; wildlife, habitat, water and wetlands protection; the storage, use, treatment and disposal of water, including processed water; and the placement, operation and reclamation of wells. In particular, many of these requirements are intended to help preserve water resources and regulate those aspects of our operations that could potentially impact surface water or groundwater. If we violate these requirements, or fail to obtain and maintain the necessary permits, we could be subject to sanctions, including the imposition of fines and penalties, as well as potential orders enjoining future operations or delays or other impediments in obtaining or renewing permits. Pursuant to such laws, regulations and permits, we may be subject to operational restrictions and have made and expect to continue to make capital and other compliance expenditures.

We could be liable for any environmental contamination at our or our predecessors' currently or formerly owned, leased or operated properties or third-party waste disposal sites. Certain environmental laws, including CERCLA, more commonly known as Superfund, impose joint and several strict liability for releases of hazardous substances at such properties or sites, without regard to fault or the legality of the original conduct. In addition to potentially significant investigation and remediation costs, environmental contamination can give rise to claims from governmental authorities and other third parties for fines or penalties, natural resource damages, personal injury and property damage.

Environmental laws, regulations and permits, and the enforcement and interpretation thereof, change frequently and generally have become more stringent over time. For example, various federal, state, provincial and local initiatives have been implemented or are under development to regulate or further investigate the environmental impacts of hydraulic fracturing, a practice that involves the pressurized injection of water, chemicals and other substances into rock formations to stimulate hydrocarbon production. In particular, the EPA has commenced a study to determine the environmental and health impacts of hydraulic fracturing and announced that it will propose standards for the treatment or disposal of wastewater from certain gas production operations. In addition, certain states and Canadian provinces in which we operate, including Colorado, Montana, Texas, Wyoming, British Columbia and Alberta, have adopted, or are considering adopting, regulations that have imposed, or could impose, more stringent permitting, transparency, disposal and well construction requirements. States and Canadian provinces in which we operate, including Texas, Colorado, Montana, Wyoming and British Columbia require public disclosure of chemicals in fluids used in the hydraulic fracturing process. Local ordinances or other regulations also may regulate, restrict or prohibit the performance of well drilling in general and hydraulic fracturing in particular, and may require baseline water well sampling. In October 2012, the Colorado Oil and Gas Conservation Commission proposed a requirement to conduct baseline water quality sampling prior to and following certain drilling operations. Such laws and regulations may result in increased scrutiny or third-party claims, or otherwise result in operational delays, liabilities and increased costs.

Regulators are also becoming increasingly focused on air emissions from our industry, including volatile organic compound emissions and water quality concerns. This increased scrutiny has led to heightened enforcement of existing regulations as well as the imposition of new air emission measures. In April 2012, the EPA issued new requirements for sulfur dioxide, volatile organic compound and hazardous air pollutant air emissions from oil and gas operations, including standards for wells that are hydraulically fractured. In addition, from time to time, initiatives are proposed that could further regulate certain exploration and production by-products as hazardous wastes and subject them to more stringent requirements. Any current or future air emission, hazardous waste or other environmental requirements applicable to our operations could curtail our operations or otherwise result in operational delays, liabilities and increased costs.

Greenhouse gas ("GHG") emission regulation is also becoming more stringent. We are currently required to implement a GHG recordkeeping and reporting program due to issuance of the EPA's subpart W regulation, which requires significant effort to quantify sources at all of our production sites and requires us to report our GHG emissions from operations. Our operations in British Columbia are subject to similar GHG reporting requirements. In addition, regulatory authorities are considering, or have developed, energy or emission measures to reduce GHG emissions. For example, the EPA has begun regulating GHG emissions from stationary sources pursuant to the Prevention of Significant Deterioration and Title V provisions of the federal Clean Air Act, as a result of which we might be required to obtain permits to construct, modify or operate facilities on account of, and implement emission control measures for, our GHG emissions. In British Columbia, we are subject to a carbon tax on our purchase or use of virtually all carbon-based fuels (including natural gas), which is payable at the time such fuel is purchased or otherwise used. Any limitation, or further regulation of GHG emissions, including through a cap-and-trade system, technology mandate, emissions tax, reporting requirement or other program, could restrict our operations and subject us to significant costs, including those relating to emission credits, pollution control equipment, monitoring and reporting. Although there is still significant uncertainty surrounding the scope, timing and effect of GHG regulation, any such regulation could have a material adverse impact on our business, financial condition, reputation and operating performance.

In addition, to the extent climate change results in more severe weather, our operations may be disrupted. For example, storms in the Gulf of Mexico could damage downstream pipeline infrastructure causing a decrease in takeaway capacity and potentially requiring us to curtail production. In addition, warmer temperatures might shorten the time during the winter months when we can access certain remote production areas resulting in decreased exploration and production activity.

## AVAILABILITY OF REPORTS AND CORPORATE GOVERNANCE DOCUMENTS

Our website is located at www.qrinc.com, and our investor relations website is located at investors.qrinc.com. The following filings are available through our investor relations website as soon as we electronically file or furnish such material to the SEC:

- our Annual Reports on Form 10-K
- Quarterly Reports on Form 10-Q
- Current Reports on Form 8-K and
- amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934.

All such postings and filings are available on our investor relations website free of charge. The SEC's web site, www.sec.gov, contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC.

We use our investor relations website as a routine channel for distribution of important information, including news releases, analyst presentations, and financial information, as a means of disclosing material non-public information and for complying with our disclosure obligations under Regulation FD. Additionally, we provide notifications of news or announcements as part of our investor relations website. Investors and others can receive notifications of new information posted on our investor relations website in real time by signing up for email alerts and RSS feeds. Accordingly, investors should monitor this portion of our website in addition to following press releases, SEC filings and public conference calls and webcasts. Further, charters for the committees of our Board and our Corporate Governance Guidelines and Code of Business Conduct and Ethics can be found on our website under the heading "Corporate Governance." Our website and the information contained therein or connected thereto shall not be deemed to be incorporated into this Annual Report on Form 10-K or in any other report or document we file with the SEC, and any references to our websites are intended to be inactive textual references only.

## EMPLOYEES

As of February 28, 2013, we had 417 employees, none of whom have collective bargaining agreements.

## EXECUTIVE OFFICERS OF THE REGISTRANT

The following information is provided with respect to our executive officers as of February 28, 2013.

| Name | Age | Position(s) |
|---|---|---|
| Thomas F. Darden | 59 | Director, Chairman of the Board |
| Glenn Darden | 57 | Director, President and Chief Executive Officer |
| Anne Darden Self | 55 | Director, Vice President - Human Resources |
| John C. Cirone | 63 | Executive Vice President, General Counsel and Secretary |
| John C. Regan | 43 | Senior Vice President - Chief Financial Officer and Chief Accounting Officer |
| Stan Page | 55 | Senior Vice President - U.S. Operations |
| Chris M. Mundy | 40 | Vice President - Chief Reservoir Engineer |
| John D. Rushford | 53 | Senior Vice President and Chief Operating Officer of Quicksilver Resources Canada Inc. |

Officers are elected by our Board of Directors and hold office at the pleasure of the Board until their successors are elected and qualified. Thomas F. Darden, Glenn Darden and Anne Darden Self are siblings. The following biographies describe the business experience of our executive officers:

**THOMAS F. DARDEN** has served on our Board of Directors since December 1997 and became Chairman of the Board in March 1999. Mr. Darden was previously employed by Mercury Exploration Company for 22 years in various executive level positions. He served as a director of Crestwood Gas Services GP LLC, the general partner of Crestwood Gas Services LP (formerly known as Quicksilver Gas Services LP), from July 2007 to September 2011.

**GLENN DARDEN** has served on our Board of Directors since December 1997 and became our Chief Executive Officer in December 1999. He served as our Vice President until he was elected President and Chief Operating Officer in March 1999. Prior to that time, he served with Mercury for 18 years, the last five as Executive Vice President. Mr. Darden previously worked as a geologist for Mitchell Energy Company LP (subsequently merged with Devon Energy). He served as a director of Crestwood Gas Services GP LLC, the general partner of Crestwood Gas Services LP (formerly known as Quicksilver Gas Services LP), from March 2007 to October 2010.

**ANNE DARDEN SELF** has served on our Board of Directors since August 1999, and became our Vice President - Human Resources in July 2000. She is also currently President of Mercury, where she has worked since 1992. From 1988 to 1991, she was employed by Banc PLUS Savings Association in Houston, Texas, initially as Marketing Director and for three years thereafter as Vice President of Human Resources. She worked from 1987 to 1988 as an Account Executive for NW Ayer Advertising Agency. Prior to 1987, she spent several years in real estate management.

**JOHN C. CIRONE** was named as our Executive Vice President - General Counsel in January 2012, after serving as our Senior Vice President - General Counsel since January 2006, and serving as our Vice President and General Counsel since July 2002. Mr. Cirone was also named as our Secretary in May 2012, and he served as our Secretary from July 2002 to November 2010. Mr. Cirone was employed by Union Pacific Resources (subsequently merged with Anadarko Petroleum Corporation) from 1978 to 2000. During that time, he served in various positions in the Law Department, and from 1997 to 2000 he was the Manager of Land and Negotiations. In 2000, he became Assistant General Counsel of Union Pacific Resources. After leaving Union Pacific Resources in August 2000, Mr. Cirone was engaged in the private practice of law prior to joining us in July 2002.

**JOHN C. REGAN** became our Senior Vice President - Chief Financial Officer and Chief Accounting Officer in April 2012, after serving as our Vice President and Chief Accounting Officer since September 2007. He also served as our Controller from September 2007 to August 2012. Mr. Regan is a Certified Public Accountant with more than 20 years of combined public accounting, corporate finance and financial reporting experience. Mr. Regan joined us from Flowserve Corporation where he held various management positions of increasing responsibility from 2002 to 2007, including Vice President of Finance for the Flow Control Division and Director of Financial Reporting. He was also a senior manager specializing in the energy industry in the audit practice of PricewaterhouseCoopers LLP, where he was employed from 1994 to 2002.

**STAN PAGE** became our Senior Vice President - U.S. Operations in June 2010, after serving as our Vice President - U.S. Operations since October 2007. Mr. Page joined us from BP America (formerly known as Amoco Production Company) where he held various management positions of increasing responsibility from 1979 to 2007, including Operations Center Manager for East Texas Operations from 2005 to 2007.

**CHRIS M. MUNDY** became our Vice President - Chief Reservoir Engineer in June 2012, after serving as our Vice President - Engineering responsible for corporate reserves from August 2010 to May 2012, Senior Director - Engineering from January 2010 to August 2010, Director - Engineering from May 2009 to January 2010 and Manager, Engineering from October 2008 to May 2009. Mr. Mundy previously served as Manager, Corporate Projects for Quicksilver Resources Canada Inc. where he led our Horseshoe Canyon Asset development program and was responsible for project planning and budgeting from September 2004 to September 2006. Prior to re-joining us in 2008, Mr. Mundy served as Manager, Engineering at Twin Butte Energy where he was responsible for corporate reserves and numerous acquisition and divestiture evaluations from September 2006 to October 2008. Mr. Mundy is a professional engineer with more than 15 years of oil and gas experience.

**JOHN D. RUSHFORD** became Senior Vice President and Chief Operating Officer of Quicksilver Resources Canada Inc. in August 2010. He is a Professional Engineer with more than 30 years of oil and gas experience in project development and business unit management. Mr. Rushford joined us from Cenovus Energy Inc. where he served as the Vice President of Business Services supporting Cenovus' business unit operations from 2005 to 2010. Prior to Cenovus he had more than 15 years of increasingly senior management positions at PanCanadian Petroleum Ltd. and EnCana Corp., including Vice President of the Chinook Business Unit that commercialized coalbed methane in Canada and as Vice President of the Fort Nelson Business Unit.

## ITEM 1A. Risk Factors

You should carefully consider the following risk factors together with all of the other information included in this Annual Report, including the financial statements and related notes, when deciding to invest in us. You should be aware that the occurrence of any of the events described in this Risk Factors section and elsewhere in this Annual Report could have a material adverse effect on our business, financial position, results of operations and cash flows.

***Commodity prices fluctuate widely, and low prices could adversely affect our ability to borrow under and comply with our debt agreements and have a material adverse impact on our business, financial condition and results of operations.***

Our revenue, profitability, and future growth depend in part on prevailing commodity prices. These prices also affect the amount of cash flow available to service our debt, fund our capital program and our other liquidity needs, as well as our ability to borrow, raise additional capital and comply with the terms of our various debt agreements, including our financial maintenance covenants. Among other things, the amount we can borrow under our Combined Credit Agreements is subject to periodic redetermination based in part on expected future prices. Lower prices may also reduce the amount of natural gas, NGLs and oil that we can economically produce.

Prices for our production fluctuate widely, particularly as evidenced by price movements between 2008 and 2012. Among the factors that can cause these fluctuations are:

- domestic and foreign demand for oil, natural gas and NGLs;
- the level and locations of domestic and foreign oil and natural gas supplies;
- the quality, price and availability of alternative fuels;
- the quantity of natural gas in storage;
- weather conditions;
- domestic and foreign governmental regulations, including environmental regulations;
- impact of trade organizations, such as the Organization of Petroleum Exporting Countries, or OPEC;
- political conditions in oil and natural gas producing regions;
- localized supply and demand fundamentals and transportation availability;
- technological advances affecting energy consumption;
- speculation by investors in oil and natural gas; and
- worldwide economic conditions.

Due to the volatility of commodity prices and the inability to control the factors that influence them, we cannot predict future pricing levels. A decrease in commodity prices without an offsetting significant increase in production or cash received from our derivatives program could have a material adverse impact on our business activities, financial condition and results of operations.

***If the prices we receive for our production decrease, our exploration and development efforts are unsuccessful or our costs increase substantially, we may be required to recognize non-cash impairment of our oil and gas properties, which could have a material adverse effect on our results of operations.***

We employ the full cost method of accounting for our oil and gas properties which, among other things, imposes limits to the capitalized cost of our assets. The capitalized cost pool cannot exceed the present value of the estimated cash flows from the underlying oil and gas reserves discounted at 10%. We recognized impairment to the carrying value of our oil and gas properties which is discussed in Item 7 of this Annual Report. We could recognize future impairments if the commodity prices utilized in determining proved reserve value cause the value of our proved reserves to decrease. Increased operating and capitalized costs without incremental increases in proved reserve value could also trigger impairment based upon decreased value of our proved reserves. The impairment of our oil and gas properties will cause us to reduce their carrying value and recognize non-cash expense, which could have a material adverse effect on our results of operations.

***Our proved reserve and production estimates depend on many assumptions that may turn out to be inaccurate and any material inaccuracies in these estimates or underlying assumptions may materially affect the quantities and present value of our proved reserves and our forecasted production.***

The process of estimating proved reserves and production is complex. In order to prepare these estimates, we and our independent reserve engineers must project future production rates and the timing and amount of future development expenditures and such projections may be inaccurate. We and the engineers must also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. In addition to interpreting available technical data, we and the engineers must also analyze other various assumptions and the estimated production. Actual future production, commodity prices, revenue, taxes, development expenditures, operating expenses and our estimated quantities of recoverable proved reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of proved reserves and the estimated production presented in our filings with the SEC. In addition, we may adjust estimates of production and estimates of proved reserves to reflect production history, results of exploration and development, prevailing commodity prices and other factors that may be beyond our control.

At December 31, 2012, 12% of our proved reserves were undeveloped. Recovery of undeveloped reserves requires additional capital expenditures and successful drilling and completion operations. Our proved reserve estimates assume that we will make significant capital expenditures to develop our proved reserves. Although we have prepared estimates of our proved reserves using SEC specifications, actual prices and costs may vary from these estimates, the development of our reserves may not occur as scheduled or actual results of that development may not be as estimated prior to drilling.

The present value of future net cash flows disclosed in Item 8 of this Annual Report is not necessarily the fair value of our proved reserves. In accordance with SEC requirements, the discounted future net cash flows from proved reserves for 2012 are based upon prices determined on an unweighted average of the preceding 12-month first-day-of-the-month prices adjusted for local differentials and operating and development costs as of period end. Actual future prices and costs may be materially higher or lower than the prices and costs used in our estimates, which are calculated in accordance with SEC requirements. Any changes in consumption by natural gas, NGL and oil purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the costs from the development and production of our oil and gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is specified by the SEC for calculating discounted future net cash flows, may not reflect current conditions. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general would affect the appropriateness of the 10% discount factor in arriving at the actual fair value of our proved reserves.

***All of our producing properties and operations are located in a small number of geographic areas, making us vulnerable to risks associated with operating in limited geographic areas.***

Our Barnett Shale Asset, Horseshoe Canyon Asset and Horn River Asset account for 76%, 15% and 8% of our 2012 production, respectively. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of oil or gas produced from the wells in these areas. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and gas producing areas, which may cause these conditions to occur with greater frequency or magnify the effect of these conditions. Due to the concentrated nature of our properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our business, financial condition and results of operations.

***Our Canadian operations present unique risks and uncertainties, different from or in addition to those we face in our U.S. operations.***

In addition to the various risks associated with our U.S. operations, risks associated with our operations in Canada, where we have substantial operations, include, among other things, risks related to increases in taxes and governmental royalties, aboriginal claims, changes in laws and policies governing operations of foreign-based companies, currency restrictions and exchange rate fluctuations and compliance with U.S. and Canadian laws and regulations, such as the U.S. Foreign Corrupt Practices Act. For example, in addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates and other matters. The royalty regime is a significant factor in the profitability of oil and gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced. Laws and policies of the U.S. affecting foreign trade and taxation may also adversely affect our Canadian operations.

In addition, the level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing our activity levels. Also, certain of our oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Therefore, seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity.

***If we are unable to obtain needed capital or financing on satisfactory terms, our ability to replace our reserves or to maintain current production levels may be limited.***

Historically, we have used our cash flow from operations, borrowings under our credit facilities and proceeds from issuances of debt and asset dispositions to fund our capital program, working capital needs and acquisitions. Our capital program may require additional financing above the level of cash generated by our operations to fund our growth. If our cash flow from operations decreases as a result of lower commodity prices or otherwise, our ability to expend the capital necessary to replace our reserves, maintain our leasehold acreage or maintain current production may be limited, resulting in decreased production and reserves over time. If our cash flow from operations is insufficient to satisfy our financing needs, we cannot be certain that additional financing will be available to us on acceptable terms or at all. Our ability to obtain bank financing or to access the capital markets for future equity or debt offerings may be limited by our financial condition or general economic conditions at the time of any such financing or offering. At December 31, 2012 we did not meet the interest coverage ratio related to our indentures which restricts our ability to incur additional debt although we can refinance our existing debt. We may need lender permission to access the capital markets and we may be unsuccessful in obtaining that permission. Even if we are successful in obtaining the necessary funds, the terms of such financings could have a material adverse effect on our business, results of operations and financial condition. If additional capital resources are unavailable, we may curtail our activities or be forced to sell some of our assets on an untimely or unfavorable basis. Drilling activity may be directed by our partners in certain areas and may result in us forfeiting acreage if we do not have sufficient capital resources to fund our portion of expenses.

***Our business involves many hazards and operational risks.***

Our operations are subject to many risks inherent in the oil and gas industry, including operating hazards such as well blowouts, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, formations with abnormal pressures, treatment plant "downtime," pipeline ruptures or spills, pollution, releases of toxic gas and other environmental hazards and risks, any of which could cause us to experience substantial losses. The occurrence of a significant accident or other event could curtail our operations and have a material adverse effect on our business, financial condition and results of operations.

***Liabilities and expenses not covered by our insurance could have a material adverse effect on our business, financial condition and results of operations.***

As a result of operating hazards, regulatory risks and other uninsured risks, we could incur substantial liabilities to third parties or governmental entities. We maintain insurance against some, but not all, of such risks and losses in accordance with customary industry practice. We are not insured against all incidents, claims or damages that might occur, and pollution and environmental risks generally are not fully insurable. Any significant accident or event that is not insured at levels that may become payable could materially adversely affect our business, financial condition and results of operations. In addition, we may be unable to economically obtain or maintain the insurance that we desire, or may elect not to obtain or renew insurance if we believe that the cost of available insurance is excessive relative to the risks presented. As a result of market conditions, premiums and deductibles for all or some certain of our insurance policies could escalate further. In some instances, certain insurance could become unavailable or available only at reduced coverage levels. Any type of catastrophic event that is not covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

***The failure to replace our proved reserves could adversely affect our business, financial condition, results of operations, production and cash flows.***

Oil and gas reserves are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our production decline rates may be significantly higher than currently estimated if our wells do not produce as expected. Further, our decline rate may change when we drill additional wells or make acquisitions or divestitures. Our proved reserves will generally decline as commodity prices decrease and as proved reserves are produced, except to the extent that we conduct successful exploration or development activities or acquire additional proved reserves. In order to maintain or increase proved reserves and production, we must continue our development drilling or undertake other replacement activities. Our planned exploration and development projects or any acquisition activities that we may undertake might not result in meaningful additional proved reserves, and we might not have continuing success drilling productive wells. Even in the event that our exploration and development projects do result in meaningful additional commercially viable proved reserves, midstream infrastructure for these proved reserves may not exist or may not be constructed, either of which could adversely impact our ability to benefit from those proved reserves. If our exploration and development efforts are unsuccessful, our leases covering acreage that is not already held by production could expire. If they do expire and if we are unable to renew the leases on acceptable terms, we will lose the right to conduct drilling activities and the resulting economic benefits associated therewith. If we are unable to develop or acquire additional proved reserves to replace our current and future production at economically acceptable terms, our business, financial condition and results of operations would be materially adversely affected. If we divest any of our producing assets our production and cash flows will be reduced. Drilling may occur at a rate directed by our partners in certain areas and may not be sufficient to grow production or reserves.

***We cannot control the operations of gas gathering, treating, processing, liquids fractionation and transportation facilities we do not own or operate.***

We deliver our production to market through gathering, treating, fractionation and transportation systems that we do not own or operate. The marketability of our production depends in part on the availability, proximity and capacity of pipeline systems owned by third parties. A portion of our production could be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, maintenance of third-party facilities or capital constraints that limit the ability of third parties to construct gathering systems, processing facilities or interstate pipelines to transport our production. Disruption of our production could negatively impact our ability to market, fractionate and deliver our production. Since we do not own or operate these assets, their continuing operation is not within our control. If any of these pipelines and other facilities becomes unavailable or capacity constrained, or if further planned development of such assets is delayed or abandoned, it could have a material adverse effect on our business, financial condition and results of operations.

***Competition in our industry is intense, and we are smaller and have a more limited operating history than many of our competitors.***

We compete with major and independent oil and gas companies for property acquisitions and for the equipment and labor required to develop and operate our properties. Many of our competitors have substantially greater financial and other resources than we do, and they may be better able to absorb the burden of drilling and infrastructure costs and any changes in federal, state, provincial and local laws and regulations than we can, which would adversely affect our competitive position. In addition, there is substantial competition for investment capital in the oil and gas industry. These competitors may be able to pay more for properties and may be able to define, evaluate, bid for and purchase a greater number of properties than we can. Our ability to explore for oil and gas prospects and to acquire additional properties in the future will depend upon our ability to conduct operations, to evaluate and select suitable properties and to complete transactions in this highly competitive environment. Furthermore, the oil and gas industry competes with other industries in supplying the energy and fuel needs of industrial, commercial and other consumers. Our inability to compete effectively with other oil and gas companies could have a material adverse impact on our business activities, financial condition and results of operations.

***Our economic hedging policy may not effectively mitigate the impact of commodity price volatility on our cash flows, and our economic hedging activities could result in losses or limit our ability to benefit from price increases. In addition, the commodity derivatives covering a significant portion our production expire in 2015 or earlier, and we may not be able to enter into commodity derivatives covering our production in future periods on favorable terms or at all.***

To reduce our exposure to commodity price fluctuations, we have entered and intend to continue to enter into commodity derivatives covering our future production, which may limit the benefit we would receive from increases in commodity prices. These arrangements also expose us to risk of financial losses in some circumstances, including the following:

- our production could be materially less than expected; or
- the counterparties to the contracts could fail to perform their contractual obligations.

If our actual production and sales for any period are less than the production covered by commodity derivatives (including reduced production due to operational delays) or if we are unable to perform our exploration and development activities as planned, we might be required to satisfy a portion of our obligations under those commodity derivatives without the benefit of the cash flow from the sale of that production, which may materially impact our liquidity. Additionally, if market prices for our production exceed collar ceilings or swap prices, we would be required to make monthly cash payments, which could materially adversely affect our liquidity.

The price for natural gas set by our derivatives has been significantly higher than the prevailing price for natural gas over the past two years. We currently maintain a portfolio of commodity derivatives covering approximately 72% of our estimated production over the next three years. However, the commodity derivatives covering a significant portion of our production expire in 2015 or earlier, and we may not be able to enter into additional commodity derivatives covering our production in future periods on favorable terms or at all. If we cannot or choose not to enter into commodity derivatives in the future, we could be more affected by changes in commodity prices than our competitors who engage in hedging arrangements. Our inability to hedge the risk of low commodity prices in the future, on favorable terms or at all, could have a material adverse impact on our business, financial condition and results of operations.

Our decision to cease accounting for our derivatives as hedges will mean that changes in their fair value will be recorded in earnings. This change, particularly on our multi-year derivatives, may create volatility to our reported earnings levels compared with our earnings had we continued to apply hedge accounting.

***Delays in obtaining oil field equipment and increases in drilling and other service costs could adversely affect our ability to pursue our drilling program.***

As commodity prices increase and exploration and development activity increases in established and emerging basins, demand and costs for drilling equipment, crews and associated supplies, equipment and services can increase significantly. We cannot be certain that in a higher commodity price environment we would be able to obtain necessary drilling equipment and supplies in a timely manner, on satisfactory terms or at all, and we could experience difficulty in obtaining, or there may be material increases in the cost of, drilling equipment, crews and associated supplies, equipment and services. In addition, drilling operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, including urban drilling, and possible title issues. As a result of increased activity levels, we have seen increases and supply limitations for the services we procure. Any such shortages or delays and price increases could adversely affect our ability to execute our drilling program.

***Our activities are regulated by complex laws and regulations that can adversely affect the cost, manner or feasibility of doing business.***

Our operations are subject to various U.S. and Canadian federal, state, provincial and local government laws and regulations that could change in response to economic or political conditions. Matters that are typically regulated include:

- discharge permits for drilling operations;
- water obtained for drilling purposes;
- drilling permits and bonds;
- reports concerning operations;
- spacing of wells;
- operations and personnel safety;
- waste disposal, including disposal wells;
- air emissions limits and permitting;
- hydraulic fracturing chemical disclosures;
- unitization and pooling of properties; and
- taxation.

From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of natural gas and oil wells below actual production capacity to conserve supplies of natural gas and oil. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, laws, regulations and tax requirements frequently are changed and subject to interpretation, and we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. We cannot assure you that existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations, will not materially adversely affect our business, results of operations and financial condition.

***We benefit from federal income tax provisions with respect to natural gas and oil exploration and development, and those provisions may be limited or repealed by future legislation.***

The Obama administration's 2013 budget proposes to eliminate certain U.S. federal income tax benefits currently available to oil and gas exploration and production companies. These proposals include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the manufacturing deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. These changes are similar to proposals in prior years that were not enacted into law. It is unclear whether such changes will be enacted or how soon they would be effective if enacted. Enactment of these proposals or other similar changes in U.S. federal income tax law could eliminate or defer certain tax credits or deductions that are currently available with respect to our activities, and any such change could negatively affect our financial condition and results of operations. See also "-Our activities are regulated by complex laws and regulations that can adversely affect the cost, manner or feasibility of doing business."

***We are subject to environmental laws, regulations and permits, including greenhouse gas requirements, which may expose us to significant costs, liabilities and obligations.***

We are subject to stringent and complex U.S. and Canadian federal, state, provincial and local environmental laws, regulations and permits relating to, among other things, the generation, storage, handling, use, disposal, gathering, transmission and remediation of natural gas, NGLs, oil and hazardous materials; the emission and discharge of such materials to the ground, air and water; wildlife, habitat, water and wetlands protection; the storage, use, treatment and disposal of water, including process water; the placement, operation and reclamation of wells; and the health and safety of our employees. These requirements may impose operational restrictions and remediation obligations, including requirements to close pits. In particular, many of these requirements are intended to help preserve water resources and regulate those aspects of our operations that could potentially impact surface water or groundwater. Failure to comply with these laws, regulations and permits may result in our being subject to litigation, fines or other sanctions, including the revocation of permits and suspension of operations, and could otherwise delay or impede the issuance or renewal of permits. We expect to continue to incur significant capital and other compliance costs related to such requirements.

We could be subject to joint and several strict liability for any environmental contamination at our and our predecessors' currently or formerly owned, leased or operated properties or third-party waste disposal sites. In addition to potentially significant investigation and remediation costs, such matters can give rise to claims from governmental authorities and other third parties for fines or penalties, natural resource damages, personal injury and property damage.

These laws, regulations and permits, and the enforcement and interpretation thereof, change frequently and generally have become more stringent over time. For example, federal and state regulators are becoming increasingly focused on air emissions from our industry, including volatile organic compound emissions. This increased scrutiny has led to heightened enforcement of existing regulations as well as the imposition of new air emission measures. With respect to GHG emissions, we are currently required to report annual GHG emissions from certain of our operations, and additional GHG emission related requirements have been implemented or are in various stages of development. Any current or future GHG or other air emission requirements could curtail our operations or otherwise result in operational delays, liabilities and increased compliance costs. In addition, to the extent climate change results in more severe weather, our or our customers' operations may be disrupted, which could curtail our exploration and production activity, increase operating costs and reduce product demand.

Our costs, liabilities and obligations relating to environmental matters could have a material adverse effect on our business, reputation, results of operations and financial condition.

***Our hydraulic fracturing operations are subject to laws and regulations that could expose us to increased costs and additional operating restrictions and delays, and adversely affect production.***

We rely and expect to continue to rely upon hydraulic fracturing, a practice that involves the pressurized injection of water, chemicals and other substances into rock formations to stimulate hydrocarbon production. Various federal, state, provincial and local initiatives have been implemented or are under development to regulate or further investigate the environmental impacts of hydraulic fracturing. In particular, the EPA has commenced a study to determine the environmental and health impacts of hydraulic fracturing and announced that it will propose standards for the treatment or disposal of wastewater from certain gas production operations. In April 2012, the EPA issued new air standards that require measures to reduce volatile organic compound emissions at new hydraulically fractured natural gas wells and existing wells that are re-fractured. Certain municipalities and states and Canadian provinces in which we operate, including Texas, Colorado, Montana, Wyoming, British Columbia and Alberta, have adopted, or are considering adopting, regulations that have imposed, or could impose, more stringent permitting, transparency, disposal and well construction requirements on hydraulic fracturing operations. For example the Railroad Commission of Texas and the Colorado Oil and Gas Conservation Commission require public disclosure of chemicals in fluids used in the hydraulic fracturing process. Similar regulations exist in British Columbia and Alberta. Local ordinances or other regulations also may regulate, restrict or prohibit the performance of well drilling in general and hydraulic fracturing in particular. In October 2012, the Colorado Oil and Gas Conservation Commission proposed a requirement to conduct baseline water quality sampling prior to and following certain drilling operations. Such laws and regulations may result in increased scrutiny or third-party claims, or otherwise result in operational delays, liabilities and increased costs. Baseline water sampling and studies are a regulatory requirement in British Columbia and Alberta.

Hydraulic fracturing can require significant quantities of water. Recently, Texas and northeastern British Columbia have been experiencing drought conditions. Any diminished access to water for use in hydraulic fracturing in Texas or other locations in which we operate, whether due to usage restrictions or drought or other weather conditions, could curtail our operations or otherwise result in operations delays or increased costs. Any current or future federal, state, provincial or local hydraulic fracturing requirements applicable to our operations, or diminished access to water for use in hydraulic fracturing, could have a material adverse effect on our business, results of operations and financial condition.

***The risks associated with our debt could adversely affect our business, financial condition and results of operations, and could cause our securityholders to experience a partial or total loss of their investment in us.***

Subject to the limits and conditions contained in our various debt agreements, we may incur additional debt. Our ability to incur additional debt and to comply with the terms of our debt agreements is affected by a variety of factors, including commodity prices and their effects on the value of our proved reserves, financial condition, results of operations and cash flows. In addition, we expect our ability to borrow under our Combined Credit Agreements will depend on our borrowing base, which will be redetermined periodically and at least twice each year based on our reserve reports and such other information deemed appropriate by the administrative agent in a manner consistent with its normal oil and gas lending criteria as it exists at the time of the redetermination. The semi-annual redetermination of the Combined Credit Agreements is scheduled for April 2013. We expect a reduction in the borrowing base from $850 million to approximately $550 million. As of February 28, 2013 we had approximately $490 million outstanding under our Combined Credit Agreements, including letters of credit. While we believe that the remaining availability of approximately $60 million together with operating cash flow will be adequate to meet our liquidity needs for the remainder of 2013, the borrowing base could be reduced below $550 million during the April or autumn redetermination and that amount may be insufficient to meet our liquidity needs. If we incur additional debt or fail to increase the quantity and value of our proved reserves, the risks that we expect to face as a result of our indebtedness could intensify.

We have demands on our cash resources, including operating expense, funding of our capital expenditures and the interest expense we expect to have on our outstanding debt. Our level of debt, the value of our oil and gas properties and other assets, the demands on our cash resources, and the provisions of our outstanding debt could have materially adverse effects on our business and on the value of our securities. For example, the provisions of our outstanding debt could:

- make it more difficult for us to satisfy our obligations with respect to our debt;
- require us to dedicate a substantial portion of our cash flow from operations to payments on our debt, thereby reducing the amount of our cash flow available for working capital, capital expenditures, acquisitions and other general corporate purposes;
- require us to make principal payments if the quantity and value of our proved reserves are insufficient to support our level of borrowings;
- limit our flexibility in planning for, or reacting to, changes in the oil and gas industry;
- place us at a competitive disadvantage compared to our competitors who may have lower debt service obligations and greater financing flexibility than we do;
- limit our financial flexibility, including our ability to borrow additional funds;
- increase our interest expense on our variable rate borrowings if interest rates increase;
- limit our ability to make capital expenditures to develop our properties;
- increase our vulnerability to exchange risk associated with Canadian dollar denominated indebtedness;
- increase our vulnerability to general adverse economic and industry conditions; and
- result in a default or event of default under our outstanding debt, which, if not cured or waived, could adversely affect our financial condition, results of operations and cash flows.

Our ability to pay principal and interest on our debt, to otherwise comply with the provisions of our outstanding debt and to refinance our debt may be affected by economic and capital markets conditions and other factors that may be beyond our control. If we are unable to service our debt and fund our other liquidity needs, we will be forced to adopt alternative strategies that may include:

- reducing or delaying capital expenditures;
- seeking additional debt financing or equity capital;
- selling assets;
- restructuring or refinancing debt; or
- reorganizing our capital structure.

We may be unable to implement any of these strategies on satisfactory terms, or at all, and our inability to do so could cause our securityholders to experience a partial or total loss of their investment in us.

***The provisions of our debt agreements and the risks associated with our debt could adversely affect our business, financial condition and results of operations.***

Our debt agreements restrict our ability to, among other things:

- incur additional debt;
- pay dividends on, or redeem or repurchase capital stock;
- make certain investments;
- incur or permit certain liens to exist;
- enter into certain types of transactions with affiliates;
- merge, consolidate or amalgamate with another company;

- transfer or otherwise dispose of assets, including capital stock of subsidiaries; and
- redeem subordinated debt.

Our debt agreements, among other things, require the maintenance of and compliance with financial and other covenants that are more fully described in Note 11 to our consolidated financial statements found in Item 8 of this Annual Report. Our ability to comply with the covenants and other provisions of our debt agreements may be affected by events beyond our control, and we may be unable to comply with all aspects of our debt agreements in the future. In addition, our ability to borrow under our Combined Credit Agreements is dependent upon the quantity and value of our proved reserves and other assets. While we believe that we will be able to comply with these covenants through the end of 2013, we do not expect to exceed the required levels by a significant margin. Accordingly, even a modest decline in prices for natural gas and NGLs, our failure to achieve anticipated cost savings or the inaccuracy in any material respect of any of the other assumptions underlying our forecast could cause us to fail to comply with the covenants contained in the Combined Credit Agreements. In addition, absent an improvement in natural gas and NGL prices, significant deleveraging from a strategic transaction, reduced interest costs on our debt through refinancing or significant reductions to our operating costs, we expect to need to seek additional covenant relief under the Combined Credit Agreements for 2014.

The provisions of our debt agreements may affect the manner in which we obtain future financing, pursue attractive business opportunities and plan for and react to changes in business conditions. In addition, failure to comply with the provisions of our debt agreements could result in an event of default which could enable the applicable creditors to declare the outstanding principal and accrued interest to be immediately due and payable. Moreover, any of our debt agreements that contain a cross-default or cross-acceleration provision could also be subject to acceleration. If we were unable to repay the accelerated amounts, the creditors could proceed against the collateral granted to them to secure such debt. If the payment of our debt is accelerated, we may have insufficient assets to repay such debt in full, and the holders of our securities could experience a partial or total loss of their investment and our business, financial condition and results of operations could be adversely affected.

***Parties with whom we do business may become unable or unwilling to timely perform their obligations to us.***

We enter into contracts and transactions with various third parties, including contractors, suppliers, customers, lenders, joint venture and other partners, and counterparties to hedging arrangements, under which such third parties incur performance or payment obligations to us. Any delay or failure on the part of one or more of such third parties to perform their obligations to us could, depending upon the nature and magnitude of such failure or failures, have a material adverse effect on our business, financial condition and results of operations.

The operations of the third parties on whom we rely for gathering and transportation services are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state, provincial and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third-party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely could have a material adverse effect on our business, financial condition and results of operations.

***We have substantial financial and other commitments related to our development of a gathering, processing and transportation system for Horn River.***

We agreed to provide NGTL with financial assurance in the form of a letter of credit to cover its costs related to the Komie North Project under our current agreement with NGTL which we expect may be amended based on the report of the NEB recommending against approval of the Komie North Project. Our financial exposure is staged in increments as the project is built and ultimately, the costs for the project could be C$296.8 million, including taxes, although we expect our exposure to be much lower if other producers commit to the project. Upon completion of the project, the requirement to provide the letters of credit will terminate.

We have also committed to deliver gas from our Horn River Asset for gathering and transport and must pay fees related to those services whether or not we deliver gas. These commitments are presented in Delivery Commitments and Purchases of Natural Gas, NGLs and Oil in Item 1. Our ability to fund these commitments may be affected by economic and capital markets conditions and other factors that may be beyond our control. In addition, we only have 104.8 Bcfe of proved reserves in our Horn River Asset as of December 31, 2012. Accordingly, our ability to deliver up to 1 Tcf of gas depends upon our ability to drill additional successful wells in our Horn River Asset, find third-party sources to supplement or satisfy our obligation or to pay a demand charge. Failure to satisfy our financial or other commitments could have a material adverse effect on our business, results of operations and financial condition.

Upon formation of Fortune Creek, we committed to drilling and completion activities in our Horn River Asset through 2014, which are detailed in Note 16 to the consolidating financial statements included in Item 8 of this Annual Report. If we do not incur these capital expenditures or are unable to negotiate a deferral of this commitment we may be subject to a penalty payment.

***Drilling locations that we decide to drill may not meet our pre-drilling expectations, may not yield oil or natural gas in commercially viable quantities and are susceptible to uncertainties that could materially alter the occurrence, timing or success of drilling.***

As of December 31, 2012, we had 60 proved undeveloped locations with proved undeveloped reserves. These identified drilling locations represent an important part of our strategy. Our ability to execute our drilling program is subject to a number of uncertainties, including the availability of capital, regulatory approvals, commodity prices, costs and drilling results. In addition, the cost and timing of drilling, completing, and operating any well are often uncertain, and new wells may not be productive. We cannot assure you that the analogies we draw from available data from other wells will be applicable to our identified drilling locations. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. Because of these uncertainties, we do not know if the drilling locations we have identified will ever be drilled or if we will be able to produce commercially viable quantities of oil or natural gas from these or any other potential drilling locations. The failure to drill our identified drilling locations on a timely basis or the failure of our drilling locations to yield oil or natural gas in commercially viable quantities could cause a decline in our proved reserves and adversely affect our ability to maintain leases, borrowing capacity, financial condition, results of operations and cash flows.

***Many of our properties are in areas that may have been partially depleted or drained by offset wells and certain of our wells may be adversely affected by actions other operators may take when operating wells that they own.***

Many of our properties are in areas that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling additional wells, that could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids towards the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations could cause a depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells could cause production from our wells to be shut in for indefinite periods of time, could result in increased lease operating expense and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

***We have multiple assets in early stages of development which have limited infrastructure.***

Our Horn River Asset, West Texas Asset and Niobrara Asset are at early stages of development. As such, there is limited information on reservoir quality which may affect the development schedule and well spacing requirements to fully recover the natural gas reserves. Additionally, the infrastructure is still in development, which could lead to delays or unexpected costs associated with getting our production to market.

***Aboriginal peoples hold certain constitutionally protected rights in Canada that could materially affect our business, financial condition and results of operations.***

Aboriginal peoples in Canada hold certain constitutionally protected rights pursuant to historic occupation of lands, historic customs and treaties with governments. Such rights may include, among other things, rights to access lands and hunting and fishing rights. The extent and nature of aboriginal rights vary from place to place in Canada, depending on historic and contemporary circumstances. All of our Horn River Asset acreage is located within the Treaty 8 settlement negotiated between the Federal Crown and First Nations and is subject to aboriginal rights associated with traditional use of the lands that could potentially impact our ability to develop and produce our mineral rights. We are not aware that any claims have been made against us in respect of our properties and assets in connection with aboriginal rights; however, if a claim arose and was successful, such claim may have a material adverse effect on our business, financial condition and results of operations. In addition, prior to making decisions that may adversely affect existing or claimed aboriginal rights, governments in Canada have a duty to consult with aboriginal people potentially affected, and in some instances, a duty to accommodate concerns raised through such consultation. Regulatory authorizations for our operations may be affected by the time required for the completion of aboriginal consultation, and operational restrictions imposed by governmental authorities pursuant to such consultation may materially affect our business, financial condition and results of operations.

***A significant increase in the differential between the NYMEX price or other benchmark prices and the prices we receive for our production could adversely affect our financial condition.***

The prices that we receive for our production often reflect a regional discount, based on the location of production, to the relevant benchmark prices, such as NYMEX, that are used for calculating the fair value of our commodity derivatives. Although there has been a demonstrated and consistent basis spread between NYMEX and where we sell our production, any increase in these differentials, if significant, could adversely affect our financial condition.

***Derivatives regulations adopted under the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, could have an adverse effect on our ability to use derivatives to reduce the effect of commodity price risk, interest rate and other risks associated with our business.***

We use commodity derivatives to manage our commodity price risk. In 2010, the U.S. Congress adopted comprehensive financial reform legislation that, among other things, establishes comprehensive federal oversight and regulation of over-the-counter derivatives, termed "swaps" and "security-based swaps" by the Dodd-Frank Act, and many of the entities that participate in the swaps markets. The Commodity Futures Trading Commission (the "CFTC") and the SEC, along with certain other regulators, must promulgate final rules and regulations to implement many of the Dodd-Frank Act swap regulatory provisions. The CFTC was given regulatory authority over swaps, which includes commodity swaps. The CFTC has finalized many, but not all, of its rules. The SEC's rules governing security-based swaps have largely not been finalized. As a result, the final form and timing of the implementation of the new swap regulatory regime affecting commodity derivatives remains uncertain.

In particular, the Dodd-Frank Act provides the CFTC with authority to adopt position limits for swaps. In 2011, the CFTC adopted a swap position limits rule, however, that rule was vacated by the U.S. District Court for the District of Columbia under a lawsuit brought by the financial services industry organizations. The CFTC has filed an appeal of the District Court's decisions with the U.S. Court of Appeals for the District of Columbia Circuit, which has not yet ruled on the appeal. It also is expected that the CFTC will revise and re-adopt position limit rules, which are expected to include position limits on commodity swaps. While the timing of implementation of final rules on position limits, their applicability to, and impact on, us and the success of any legal challenge to their validity remain uncertain, there can be no assurance that, when in place, position limit rules will not have a material adverse impact on us by affecting the prices of or market for commodities relevant to our operations and/or by reducing the availability to us of commodity derivatives.

The Dodd-Frank Act will also impose a number of other new requirements on swap transactions and subject swap dealers and major swap participants to significant new regulatory requirements, which in certain cases may cause them to conduct their activities through new entities that may not be as creditworthy as our current counterparties, all of which may have a material adverse effect on us. The impact of this new regulatory regime on the availability, pricing and terms and conditions of commodity derivatives, remains uncertain, but there can be no assurance that it will not have a materially adverse effect on our ability to hedge our exposure to commodity prices.

In addition, under the Dodd-Frank Act, swap dealers and major swap participants will be required to collect initial and variation margin from certain end-users of swaps. The rules implementing many of these requirements have not all been finalized and therefore the timing of their implementation and their applicability to us remains uncertain. Depending on the final rules and definitions ultimately adopted, we might in the future be required to post collateral for some or all of our derivative transactions, which could cause liquidity issues for us by reducing our ability to use our cash or other assets for capital expenditures or other corporate purposes and reduce our ability to execute strategic hedges to reduce commodity price uncertainty and protect cash flows.

If we reduce our use of derivatives as a result of the Dodd-Frank Act, the regulations promulgated under it and the changes to the nature of the derivatives markets, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. In addition, the Dodd-Frank Act was intended, in part, to reduce the volatility of commodity prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to natural gas, NGLs and oil. Our revenue could, therefore, be adversely affected if commodity prices were to decrease.

***The loss of key personnel could adversely affect our ability to operate.***

Our operations are dependent on a relatively small group of key management personnel, including our executive officers. There is a risk that the services of all of these individuals may not be available to us in the future. Because competition for experienced personnel in our industry can be intense, we may be unable to find acceptable replacements with comparable skills and experience and their loss could adversely affect our ability to operate our business.

***A small number of existing stockholders exercise significant control over our company, which could limit your ability to influence the outcome of stockholder votes.***

As of February 28, 2013, members of the Darden family, together with entities controlled by them, beneficially owned approximately 30% of our outstanding common stock. As a result, they are generally able to significantly affect the outcome of stockholder votes, including votes concerning the election of directors, the adoption or amendment of provisions in our charter or bylaws and the approval of mergers and other significant corporate transactions.

***Our amended and restated certificate of incorporation, restated bylaws and stockholder rights plan contain provisions that could discourage an acquisition or change of control without our board of directors' approval.***

Our amended and restated certificate of incorporation and restated bylaws contain provisions that could discourage an acquisition or change of control without our board of directors' approval. In this regard:

- our board of directors is authorized to issue preferred stock without stockholder approval;
- our board of directors is classified; and
- advance notice is required for director nominations by stockholders and actions to be taken at annual meetings at the request of stockholders.

In addition, we have amended and extended a stockholder rights plan, which could also impede a merger, consolidation, takeover or other business combination involving us, even if that change of control might be beneficial to stockholders, thus increasing the likelihood that incumbent directors will retain their positions. In certain circumstances, the fact that corporate devices are in place that will inhibit or discourage takeover attempts could reduce the market value of our common stock.

***If our plan to separate certain of our Barnett Shale assets into a new publicly-traded master limited partnership is further delayed or not completed, our stock price may decline and our growth potential may not be enhanced.***

In 2011, we announced a plan to separate certain of our mature onshore oil and gas properties in our Barnett Shale Asset into a new publicly-traded master limited partnership ("MLP"). In February 2012, we filed an initial registration statement on Form S-1 in connection with this planned initial public offering. Completion of this plan is subject to market conditions and numerous other risks beyond our control, including, but not limited to, the general economy, credit markets, equity markets and energy prices. Therefore, it is possible that MLP will not complete an offering of securities, will not raise the planned amount of capital even if an offering of securities is completed and will not be able to complete its proposed actions on the desired timetable. Furthermore, the structure, nature, purpose and proposed manner of offering of MLP securities may change materially from those anticipated, including the effects of our current joint venture marketing process. If the MLP transaction is not completed or is delayed, our stock price may decline and our growth potential may not be enhanced.

If completed, our plan to separate portions of our Barnett Shale Asset may not achieve its intended results and could have an adverse effect on us due to a number of factors. Following the completion of the planned initial public offering, we will initially be the largest unitholder of MLP, holding common units, subordinated units and incentive distribution rights. We cannot assure you that the trading price of our common stock, which will include our retained investment in MLP, as adjusted for any changes in the combined capitalization of these companies, will be equal to or greater than the trading price of our common stock prior to the planned initial public offering of MLP.

In addition, MLP, and therefore our retained investment in MLP, will be subject to the risks normally attendant to businesses in the oil and natural gas industry, including most of the same risks to which we are subject.

Our 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. Any offers, solicitations of offers to buy, or any sales of securities of MLP will be made only in accordance with the registration requirements of the Securities Act of 1933 or an exemption therefrom.

***We have identified material weaknesses in our internal controls that, if not properly corrected, could result in material misstatements in our financial statements.***

We have identified two material weaknesses in our system of internal control over financial reporting as of December 31, 2012. A material weakness is a deficiency, or combination of deficiencies in internal controls over financial reporting that results in a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

We did not maintain operating effectiveness of our controls over the documentation in 2012 for derivatives that had fair value at the designation date. Our controls failed to detect that, for contracts designated as hedges that had a fair value on the date of designation, there were undocumented potential sources of ineffectiveness. Specifically, our documentation did not include an assessment of whether interest rate changes could cause the derivatives to not be effective over their lives, which is required due to the presence of fair value on the designation date. Effective December 31, 2012, management discontinued the use of hedge accounting on all derivative contracts and does not expect the material weakness associated with hedge accounting to recur. If, in the future, we were to begin to designate our derivatives as hedges we would need to enhance our controls regarding consideration of all sources of ineffectiveness.

We also had a material weakness related to the operating effectiveness of controls over deferred income taxes. We had difficulty in preparing a timely reconciliation of certain temporary differences, particularly related to the tax basis in property, plant and equipment, from our provision to our tax returns and our tax subledger. The Company is in the process of implementing system and procedural changes to prevent these issues from recurring in 2013. These issues were exacerbated by turnover within the tax department in 2012 and 2013, and the Company is in the process of evaluating its resource needs in this area.

A significant deficiency as of December 31, 2012 relates to the operating effectiveness of our controls for our calculation of the asset retirement obligation for our Canadian assets. In response, management has enhanced its controls in this area and believes that these enhancements, when repeated as applicable in future periods, will remediate the matter.

If we are not able to remedy the control deficiencies in a timely manner, we may be unable to provide holders of our securities with the required financial information in a timely and reliable manner, either of which could subject us to litigation and regulatory enforcement actions.

## ITEM 1B. Unresolved Staff Comments

None.

## ITEM 2. Properties

A detailed description of our significant properties and associated 2012 developments can be found in Item 1 of this Annual Report, which is incorporated herein by reference.

## ITEM 3. Legal Proceedings

On December 18, 2012, Vantage Fort Worth Energy LLC ("Vantage") served a lawsuit against us and others in the 352nd Judicial District Court of Texas in Tarrant County, Texas asserting claims for trespass to try title, suit to quiet title, trespass and conversion in connection with 16 wells located on a 158.75 acre tract in Tarrant County, Texas. They seek declaratory and injunctive relief, an accounting and an unspecified amount of actual damages, interest and court costs. We filed our answer on January 14, 2013. On January 28, 2013, Vantage filed its Motion for Non-suit with respect to certain defendants and First Amended Petition. Vantage's current complaint also seeks an unspecified amount of actual damages, interest and costs. We plan a vigorous defense in this matter.

## ITEM 4. Mine Safety Disclosures

Not applicable.

## PART II

### ITEM 5. Market For Registrant's Common Equity, Related Stockholder Matters and Issuer Purchase of Equity Securities

**Market Information**

Our common stock is traded on the New York Stock Exchange under the symbol "KWK."

The following table sets forth the quarterly high and low in-trading sales prices of our common stock for the periods indicated below.

| | HIGH | LOW |
|---|---|---|
| **2012** | | |
| Fourth Quarter | $ 4.96 | $ 2.62 |
| Third Quarter | 5.97 | 3.28 |
| Second Quarter | 5.65 | 2.93 |
| First Quarter | 7.18 | 4.14 |
| **2011** | | |
| Fourth Quarter | $ 8.87 | $ 6.17 |
| Third Quarter | 14.90 | 7.41 |
| Second Quarter | 15.41 | 13.00 |
| First Quarter | 15.98 | 13.63 |

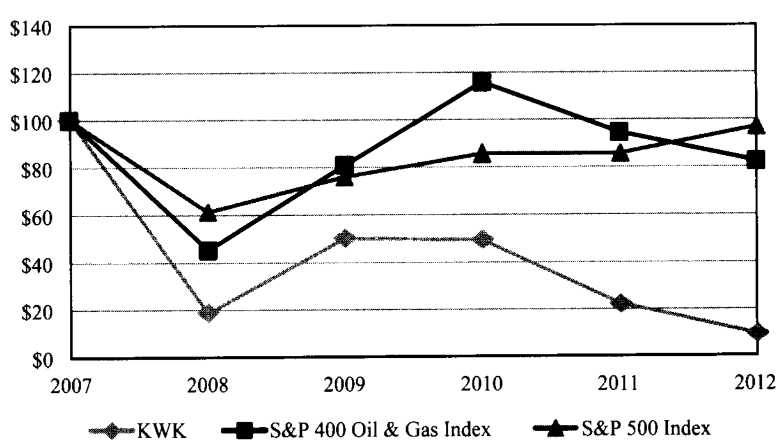
As of February 28, 2013, there were approximately 660 common stockholders of record.

We have not paid cash dividends on our common stock and intend to retain our cash flow from operations for the future operation and development of our business. In addition, we have debt agreements that restrict payments of dividends.

**Performance Graph**

The following performance graph compares the cumulative total stockholder return on Quicksilver common stock (KWK) with the Standard & Poor's 500 Stock Index (the "S&P 500 Index") and the Standard & Poor's 400 Oil and Gas Index (the "S&P 400 Oil & Gas Index") for the period from December 31, 2007 to December 31, 2012, assuming an initial investment of $100 and the reinvestment of all dividends, if any.

**Comparison of Cumulative Five Year Total Return**



**Issuer Purchases of Equity Securities**

The following table summarizes our repurchases of Quicksilver common stock during the quarter ended December 31, 2012.

| Period | Total Number of Shares Purchased [1] | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Plan [2] | Maximum Number of Shares that May Yet Be Purchased Under the Plan [2] |
|---|---|---|---|---|
| October 2012 | 1,323 | $ 4.19 | — | — |
| November 2012 | 103,486 | $ 3.17 | — | — |
| December 2012 | — | — | — | — |
| Total | 104,809 | $ 3.18 | — | — |

(1) Represents shares of common stock surrendered by employees to satisfy the income tax withholding obligations arising upon the vesting of restricted stock issued under our stock plans.

(2) We do not have a publicly announced plan for repurchasing our common stock.

## ITEM 6. Selected Financial Data

The following table sets forth, as of the dates and for the periods indicated, our selected financial information and is derived from our audited consolidated financial statements for such periods. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and notes thereto contained in this Annual Report. The following information is not necessarily indicative of our future results:

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2012 (1) | 2011 (2) | 2010 (3) | 2009 (4) | 2008 (5) |
| | (In thousands, except for per share data) | | | | |
| **Operating Results Information** | | | | | |
| Total revenue | $ 709,038 | $ 943,623 | $ 928,331 | $ 832,735 | $ 800,641 |
| Operating income (loss) | (2,465,761) | 122,604 | 804,134 | (613,873) | (249,697) |
| Income (loss) before income taxes | (2,648,176) | 147,909 | 713,828 | (836,856) | (585,077) |
| Net income (loss) | (2,352,606) | 90,046 | 455,290 | (545,239) | (373,622) |
| Net income (loss) attributable to Quicksilver | (2,352,606) | 90,046 | 445,566 | (557,473) | (378,276) |
| Diluted earnings (loss) per common share | $ (13.83) | $ 0.52 | $ 2.50 | $ (3.30) | $ (2.33) |
| Dividends paid per share | — | — | — | — | — |
| **Financial Condition Information** | | | | | |
| Property, plant and equipment - net | $ 1,029,058 | $ 3,460,519 | $ 3,063,245 | $ 2,542,845 | $ 3,298,830 |
| Midstream assets held for sale - net | — | — | 27,178 | 548,508 | 492,733 |
| Total assets | 1,381,788 | 3,995,462 | 3,507,734 | 3,612,882 | 4,498,208 |
| Long-term debt | 2,063,206 | 1,903,431 | 1,746,716 | 2,427,523 | 2,586,045 |
| All other long-term obligations | 283,588 | 495,939 | 248,762 | 121,877 | 282,101 |
| Total equity | (1,132,797) | 1,261,919 | 1,069,905 | 696,822 | 1,211,563 |
| **Cash Flow Information** | | | | | |
| Cash provided by operating activities | $ 227,727 | $ 253,053 | $ 397,720 | $ 612,240 | $ 456,566 |
| Capital expenditures | 485,479 | 690,607 | 695,114 | 693,838 | 1,286,715 |

(1) Operating loss for 2012 includes charges for impairment of $2.6 billion for certain midstream assets in Colorado and U.S. and Canadian oil and gas properties. Net loss includes a tax valuation allowance of $595.3 million.

(2) Operating income for 2011 includes gains of $217.9 million from the sale of BBEP Units. Operating income also includes charges for impairment of $58.0 million and $49.1 million for our midstream assets in Texas, and Canadian oil and gas properties, respectively.

(3) Operating income for 2010 includes gains of $494.0 million and $57.6 million from the sales of KGS and BBEP Units, respectively. Operating income also includes charges for impairment of $28.6 million and $19.4 million for our HCDS and Canadian oil and gas properties, respectively.

(4) Operating loss for 2009 includes charges of $786.9 million and $192.7 million for impairments associated with our U.S. and Canadian oil and gas properties, respectively. Net loss also includes $75.4 million of income attributable to our proportionate ownership of BBEP and a charge of $102.1 million for impairment of that investment.

(5) Operating loss for 2008 includes a charge of $633.5 million for impairment associated with our U.S. oil and gas properties. Net loss also includes $93.3 million for pre-tax income attributable to our proportionate ownership of BBEP and a pre-tax charge of $320.4 million for impairment of that investment.

## ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following Management's Discussion and Analysis ("MD&A") is intended to help readers of our financial statements understand our business, results of operations, financial condition, liquidity and capital resources. MD&A is provided as a supplement to, and should be read in conjunction with, the other sections of this Annual Report. Until the sale of all of our interests in KGS, we conducted our operations in two segments: (1) our more dominant exploration and production segment, and (2) our significantly smaller midstream segment. Except as otherwise specifically noted, or as the context requires otherwise, and except to the extent that differences between these segments or our geographic segments are material to an understanding of our business taken as a whole, we present this MD&A on a consolidated basis.

Our MD&A includes the following sections:

- *Overview of quarter restatement* – a description of the restatement of our historical quarterly financial statements
- *Overview* – a general description of our business; the value drivers of our business; and key indicators
- *2012 Highlights* – a summary of significant activities and events affecting Quicksilver
- *2013 Capital Program* – a summary of our planned capital expenditures during 2013
- *Financial Risk Management* – information about debt financing and financial risk management
- *Results of Operations* – an analysis of our consolidated results of operations for the three years presented in our financial statements
- *Liquidity, Capital Resources and Financial Position* – an analysis of our cash flows, sources and uses of cash, contractual obligations and commercial commitments
- *Critical Accounting Estimates* – a discussion of critical accounting estimates that represent choices between acceptable alternatives and/or require management judgments and assumptions.

## OVERVIEW OF QUARTER RESTATEMENT

As part of our year-end 2012 procedures, we concluded that the documentation for our derivatives designated during 2012 that had fair value on the dates they were initially designated as hedges failed to give consideration to all sources of ineffectiveness. Specifically, our documentation did not include an assessment of whether interest rate changes could cause the instruments to not be effective over the life of the contract, which was required given the presence of fair value at the date of hedge designation. Management had documented its assessment of interest rate risk in 2011 on similar derivatives and concluded its effect to be immaterial and, thus, did not document the risk in 2012. Accordingly, these derivatives did not qualify for hedge accounting in 2012 and their changes in value must be recognized in earnings.

Because the derivatives did not qualify for hedge accounting, their inclusion in the U.S. and Canadian full cost ceiling was inappropriate. Thus, our full cost ceiling calculations were revised and resulted in restatements to impairment expense recognized in earlier quarters. Also, we determined that the deferred taxes used in our Canadian ceiling test for the first two quarters of 2012 included temporary differences for non-property related items. We have restated the ceiling impairments from the interim quarters to correct for these inclusions. The impairment expense that resulted from the ceiling calculation restatements also caused reductions to our depletion rates for the quarters and we have restated depletion expense. Income taxes have also been restated for each of the 2012 quarters to reflect the foregoing restated items.

The following table and subsequent section discuss the effect of the restatement for impacted line items on the consolidated statement of income (loss) for the first three quarters in 2012. Amounts related to derivatives previously classified in other revenue have been reclassified to derivative gains (losses), net. The total impact to the income statement is shown in the Supplemental Selected Quarterly Financial Statements included in Item 8 to this Annual Report.

| | For the Three Months Ended March 31, 2012 | | For the Three Months Ended June 30, 2012 | | For the Three Months Ended September 30, 2012 | |
|---|---|---|---|---|---|---|
| | As previously reported | As restated | As previously reported | As restated | As previously reported | As restated |
| Production revenue | 171,820 | 166,454 | 150,503 | 150,311 | 157,699 | 156,288 |
| Derivative gain (loss), net | — | (6,664) | — | 33,139 | — | (60,377) |
| Total revenue | 145,469 | 172,866 | 168,562 | 194,018 | 177,702 | 118,188 |
| Depletion, depreciation and accretion | 54,439 | 54,439 | 51,942 | 48,016 | 43,209 | 34,014 |
| Impairment | 62,746 | 317,928 | 991,921 | 1,199,726 | 546,835 | 551,132 |
| Operating income (loss) | (40,200) | (267,985) | (974,589) | (1,153,012) | (521,935) | (576,551) |
| Income (loss) before income taxes | (85,018) | (312,803) | (1,019,430) | (1,197,853) | (569,410) | (624,026) |
| Income tax (expense) benefit | 25,094 | 101,238 | 346,889 | 395,831 | (82,352) | (166,494) |
| Net income (loss) | (59,924) | (211,565) | (672,541) | (802,022) | (651,762) | (790,520) |
| Earnings (loss) per common share - diluted | (0.35) | (1.24) | (3.96) | (4.72) | (3.83) | (4.65) |

*Quarter Ended March 31, 2012*

The derivative restatement adjustment decreased production revenue by $3.6 million and $1.8 million for the U.S. and Canada, respectively, while derivative gains increased $20.7 million and $12.0 million for the U.S. and Canada, respectively. Impairment expense increased as the result of these derivatives no longer being included in the cost center ceiling by $115.7 million and $139.5 million for the U.S. and Canada, respectively. The income tax impact of these adjustments resulted in an increase to the tax benefit of $41.9 million and $34.2 million for the U.S. and Canada, respectively. Our consolidated net loss increased $151.6 million. The restatement increased diluted net loss per share by $0.89, from diluted net loss per share of $0.35 as previously reported, to diluted net loss per share of $1.24.

*Quarter Ended June 30, 2012*

The derivative restatement adjustment increased production revenue by $1.3 million for the U.S. and decreased production revenue by $1.5 million for Canada, while derivative gains increased $22.2 million and $3.5 million for the U.S. and Canada, respectively. Impairment expense increased as the result of these derivatives no longer being included in the cost center ceiling by $144.0 million and $63.8 million for the U.S. and Canada, respectively, while depletion expense decreased $1.3 million and $2.6 million for the U.S. and Canada, respectively. The income tax impact of these adjustments resulted in an increase to the tax benefit of $34.3 million and $14.6 million for the U.S. and Canada, respectively. Our consolidated net loss increased $129.5 million. The restatement increased diluted net loss per share by $0.76, from diluted net loss per share of $3.96 as previously reported, to diluted net loss per share of $4.72.

*Quarter Ended September 30, 2012*

The derivative restatement adjustment decreased production revenue by $0.3 million and $1.1 million for the U.S. and Canada, respectively, while derivative losses increased $42.8 million and $15.3 million for the U.S. and Canada, respectively. Impairment expense increased as the result of these derivatives no longer being included in the cost center ceiling by $43.4 million for the U.S. and decreased impairment expense by $39.1 million for Canada, while depletion expense decreased $3.3 million and $5.9 million for the U.S. and Canada, respectively. The income tax impact of these adjustments resulted in an increase to the tax expense of $75.3 million and $8.8 million for the U.S. and Canada, respectively. Our consolidated net loss increased $138.8 million. The restatement increased diluted net loss per share by $0.82, from diluted net loss per share of $3.83 as previously reported, to diluted net loss per share of $4.65.

## OVERVIEW

We are an independent oil and gas company engaged primarily in the acquisition, exploration, development, and production of onshore oil and gas based in Fort Worth, Texas. We focus primarily on unconventional reservoirs where hydrocarbons may be found in challenging geological conditions such as fractured shales, coalbeds and tight sands. We generate revenue, income and cash flows by producing and selling natural gas, NGLs and oil. We conduct acquisition, exploration, development, and production activities to replace the reserves that we produce.

At December 31, 2012, 76% and 23% of our proved reserves were natural gas and NGLs, respectively. Consistent with one of our business strategies, we continue to develop our unconventional resources by applying our expertise to our development projects in our Barnett Shale Asset, Horseshoe Canyon Asset and Horn River Asset, which had 81%, 11% and 7%, respectively, of our proved reserves at December 31, 2012. During 2012, based on the success of our exploration in our Horn River Asset, we began to consider this a development area, particularly in the southern portion of our acreage. Our acreage in our Horn River Asset provides us the most immediate additional opportunity for further application of our unconventional resources expertise.

Our focus for 2013 is on the execution of strategic transactions and the improvement of our capital structure through deleveraging and the extension of our debt maturities. If we are successful with these priorities in 2013, we would expect that we would focus on three other value drivers in the future:

- reserve growth;
- production growth; and
- maximizing our operating margin.

Our reserve growth depends on our ability to fund a drilling program. It also relies on our ability to apply our technical and operational expertise to explore and develop unconventional reservoirs. We strive to increase reserves and production through aggressive management of our operations and through relatively low-risk developmental drilling. All of our development and exploratory programs are aimed at providing us with opportunities to develop unconventional reservoirs.

We believe the acreage we hold in our core operating areas is well suited for production increases through developmental drilling. We perform workover and infrastructure projects to reduce ongoing operating costs and enhance current and future production rates. We regularly review the properties we operate to determine if steps can be taken to efficiently increase reserves and production.

In evaluating the results of our efforts, we consider the capital efficiency of our drilling program and also measure the following key indicators, whose recent results are shown below:

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2012** [2] | **2011** | **2010** |
| Organic reserve growth [1] | (42)% | 1% | 19% |
| Production volume (Bcfe) | 131.8 | 150.6 | 129.6 |
| Cash flow from operating activities (in millions) | $ 227.7 | $ 253.1 | $ 397.7 |
| Diluted earnings (loss) per share | $ (13.83) | $ 0.52 | $ 2.50 |

(1) This ratio is calculated by subtracting beginning of the year proved reserves from adjusted end of the year proved reserves and dividing by beginning of the year proved reserves. Adjusted end of the year reserves are calculated by adding back divested reserves and production and deducting acquired reserves from end of the year reserves.

(2) During 2012, Quicksilver recognized substantial negative reserve revisions due to lower average SEC commodity prices compared to prior periods. As such, we recognized a 1.2 Tcfe negative revision for all of 2012, which represents a 44% decline compared to 2011 year-end reserves. Organic reserve adds in 2012 were approximately 49 Bcfe, which represents less than 2% growth from 2011. The modest level of reserve additions results from two main factors: 1) approximately 85% of the 22 gross wells drilled in the Barnett Shale in 2012 were PUD locations at year-end 2011. Therefore, no new reserves were recognized for these PUD locations after bringing them on line; and 2) we did not recognize significant additional PUD locations at year-end 2012 due the influence of commodity prices on the five-year development profile. Customarily, we would recognize additional PUD locations to offset drilled locations during the year provided the new PUDs meet the SEC's standards, including the five-year limitation.

The organic reserve growth ratio is a supplemental measure that we use to assess how successfully we are implementing our business strategy of pursuing disciplined organic growth. We believe that total reserve growth is a multi-year key value driver of which organic reserve growth is a component. Reserve estimation has inherent limitations which are detailed in our Risk Factors in Item 1A and include assumptions regarding future production rates, timing and amount of future development expenditures, results of geological, geophysical, production and engineering data and economic factors. Any inaccuracies in these assumptions could materially affect the estimated quantities of proved reserves. Item 8 "Supplemental Oil and Gas Information" contains additional information about our reserves.

## 2012 HIGHLIGHTS

*Joint Venture Update*

On December 28, 2012, we entered into an agreement with SWEPI LP to jointly develop our oil and gas interests in the Niobrara formation of the Sand Wash Basin and to establish an Area of Mutual Interest ("AMI") covering in excess of 850,000 acres. Each party assigned to the other a 50% working interest in the majority of its combined acreage so that each party owns a 50% interest in more than 320,000 acres and has the right to a 50% interest in any acquisition within the AMI. SWEPI paid us an equalization payment for 50% of the acreage contributed by us in excess of the acreage that SWEPI contributed. SWEPI is the operator of the majority of the jointly owned lands. This relationship is strategic to the development of the Niobrara Asset as it created contiguous acreage blocks, which will lead to a more orderly and cost-effective development of the basin.

Quicksilver is engaged in confidential negotiations with a potential buyer to sell a non-operated minority working interest in its Barnett Shale Asset.

We continue our efforts to achieve a joint venture in our Horn River Asset in Northeast British Columbia, with the downstream marketing of the gas a top priority. We plan minimal capital spending in our Horn River Asset pending completion of a joint venture.

*Horn River Development*

We completed our first multi-well pad in our Horn River Asset during June and July 2012. The initial instantaneous production results from these new wells ranged between 23 MMcfd and 34 MMcfd, which exceeded our expectations. Production was curtailed from the new eight-well pad since August 2012 due to a delay in commissioning of a third-party's treating facility and limitations of surface equipment. In December 2012, we secured temporary alternative treating and transportation and increased gross production to 100 MMcfd within 15 days. We do not have a firm date for when the new treating facility, at which we have firm capacity, will be operable, but we believe we have sufficient treating and transportation capacity in the interim to meet our needs.

On January 30, 2013, the Canadian NEB issued its report recommending against approval of NGTL's Komie North Project, which included a 75-mile pipeline that would connect NGTL's Alberta system to a meter station planned to be constructed on our acreage in the Horn River Basin. We believe the NEB's recommendation against the Komie North Project will be adopted by the federal authority. The NEB concluded that the evidence presented at this time did not justify a 36-inch line as proposed; however, its recommendation notwithstanding, the NEB emphasized its belief in the long-term prospects for development of the Horn River Basin. We believe NGTL will undertake efforts to secure additional shipper support for this pipeline.

We had previously provided $30 million in letters of credit, which were reduced to $14 million during March 2013. We believe future financial assurances, upon a revised application, which we expect may be delayed by up to two years, would be reduced proportionately relative to additional shipper support. Likewise, we are planning to defer drilling in the Horn River Basin until 2014 and have the ability to defer construction of a natural gas treating facility until at least 2016 to coincide with the revised timelines for the Komie North Project.

Our ability to sell gas at the Station 2 and AECO hubs has not been impacted by the NEB's recommendation, as its acreage is served by existing treating facilities and pipelines which today can accommodate in excess of 1 billion cubic feet per day. Due to the pace of development in the basin by all producers, discounted excess capacity is available in the region to meet Quicksilver's needs.

*Emerging Basins*

During 2012, we drilled and completed three vertical wells in the Sand Wash Basin using a variety of stimulation methods and drilled one well. We are currently conducting exploratory activities and have eight producing wells as of December 31, 2012.

During 2012, we continued to build an oil prospective acreage position in the Bone Springs and Wolfcamp formations in the Midland and Delaware basins in West Texas. Our leases total 125,000 acres across Reeves, Pecos, Jeff Davis, Upton and Crockett Counties. We drilled and completed our first short-lateral well in Pecos County in August 2012, which targeted the Third Bone Springs formation, and we drilled and completed another short-lateral well in Upton County in December 2012, which targeted the Wolfcamp formation.

*Master Limited Partnership*

In February 2012, we filed a Form S-1 with the SEC to begin the registration and sale of limited partnership interests in a master limited partnership holding certain of our mature properties in our Barnett Shale Asset. We amended the registration statement in May to include financial statements for 2011 and to address comments received from the SEC and again in June to include financial statements for the first quarter of 2012 and to address further comments received from the SEC. In July 2012, we were informed that the SEC had no further comments. During the fourth quarter of 2012 we recognized an expense for the deferred filing fees associated with this offering since the transaction has been dormant since June 2012. This accounting treatment does not preclude us from updating the registration document at a later date and we will continue to monitor market conditions to assess the timing of an offering, which may be influenced by a joint venture covering our Barnett Shale Asset.

*Significant Contract Revisions*

In August 2012, we amended our Combined Credit Agreements primarily to relax the financial covenants through the second quarter of 2014. Specific changes to the Combined Credit Agreements are outlined in Note 11 to the consolidated financial statements in Item 8.

## 2013 CAPITAL PROGRAM

We expect our 2013 capital program to be spent in the following areas:

| | (In millions) |
|---|---|
| Barnett Shale | $ 10 |
| Niobrara | 35 |
| West Texas | 6 |
| Total U.S. | 51 |
| Horn River | 29 |
| Horseshoe Canyon | 3 |
| Total Canada | 32 |
| Corporate [1] | 37 |
| Total Company | $ 120 |

[1] Includes capitalized interest expense and capitalized internal costs.

We expect our 2013 production volume to be between 335 and 345 MMcfe per day.

## FINANCIAL RISK MANAGEMENT

We have established internal control policies and procedures for managing risk within our organization. The possibility of decreasing prices received for our natural gas, NGL and oil production is one of the several risks that we face. We seek to manage this risk by entering into derivative contracts. We have mitigated the downside risk of adverse price movements through the use of these derivatives but, in doing so, have also limited our ability to benefit from favorable price movements. Our commodity price strategy enhances our ability to execute our development and exploration programs, meet debt service requirements and pursue acquisition opportunities even in periods of price volatility or depression. Item 7A of this Annual Report contains details of our commodity price and interest rate risk management.

## RESULTS OF OPERATIONS

"Other U.S." refers to the combined amounts for our operations in our Niobrara Asset, West Texas Asset and Southern Alberta Asset.

### Revenue

We aggregate production revenue and realized cash gains (losses) on derivatives not treated as hedges in measuring revenue from our oil and gas production. Historically, we have used hedge accounting and combining these items mirrors our views of the derivatives' usefulness and provides more comparability.

Production Revenue and Realized Cash Gains (Losses) on derivatives by operating area:

| | Natural Gas | | | NGL | | | Oil | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 |
| | | | | | | (In millions) | | | | | | |
| Barnett Shale | $ 200.9 | $ 376.5 | $ 321.2 | $ 137.5 | $ 216.6 | $ 160.6 | $ 10.9 | $ 11.8 | $ 11.8 | $ 349.3 | $ 604.9 | $ 493.6 |
| Other U.S. | 0.6 | 1.1 | 2.3 | 0.5 | 0.6 | 0.5 | 13.7 | 12.3 | 10.0 | 14.8 | 14.0 | 12.8 |
| Hedging | 151.3 | 100.2 | 250.2 | 23.5 | (46.1) | (24.1) | — | — | — | 174.8 | 54.1 | 226.1 |
| U.S. | 352.8 | 477.8 | 573.7 | 161.5 | 171.1 | 137.0 | 24.6 | 24.1 | 21.8 | 538.9 | 673.0 | 732.5 |
| Horseshoe Canyon | 48.2 | 79.2 | 90.4 | 0.1 | 0.1 | 0.2 | — | — | — | 48.3 | 79.3 | 90.6 |
| Horn River | 23.9 | 17.4 | 10.6 | — | — | — | — | — | — | 23.9 | 17.4 | 10.6 |
| Hedging | 19.8 | 30.8 | 22.7 | — | — | — | — | — | — | 19.8 | 30.8 | 22.7 |
| Canada | 91.9 | 127.4 | 123.7 | 0.1 | 0.1 | 0.2 | — | — | — | 92.0 | 127.5 | 123.9 |
| Consolidated production revenue | $ 444.7 | $ 605.2 | $ 697.4 | $ 161.6 | $ 171.2 | $ 137.2 | $ 24.6 | $ 24.1 | $ 21.8 | $ 630.9 | $ 800.5 | $ 856.4 |
| U.S. realized cash derivative gains | 23.0 | — | — | — | — | — | — | — | — | 23.0 | — | — |
| Canada realized cash derivative gains | 19.8 | — | — | — | — | — | — | — | — | 19.8 | — | — |
| Consolidated realized cash derivative gains | 42.8 | — | — | — | — | — | — | — | — | 42.8 | — | — |
| Consolidated production revenue and realized cash derivative gains [1] | $ 487.5 | $ 605.2 | $ 697.4 | $ 161.6 | $ 171.2 | $ 137.2 | $ 24.6 | $ 24.1 | $ 21.8 | $ 673.7 | $ 800.5 | $ 856.4 |

(1) Realized cash derivative gains from derivatives not treated as hedges are included in derivative gains (losses), net. Unrealized derivative gains and losses and hedge ineffectiveness make up the the remainder of derivative gains (losses), net as reported on our statement of income. A discussion of derivative gains (losses), net is found elsewhere in our discussion of our results of operation. Total revenue is comprised of production revenue, derivative gains (losses), net, sales of purchased natural gas and other revenue.

Average Daily Production Volume by operating area:

| | Natural Gas | | | NGL | | | Oil | | | Equivalent Total | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 |
| | | (MMcfd) | | | (Bbld) | | | (Bbld) | | | (MMcfed) | |
| Barnett Shale | 206.2 | 261.8 | 207.9 | 11,090 | 12,117 | 11,913 | 333 | 352 | 433 | 274.8 | 336.6 | 281.9 |
| Other U.S. | 0.6 | 0.8 | 1.5 | 26 | 24 | 25 | 451 | 396 | 397 | 3.5 | 3.3 | 4.0 |
| U.S. | 206.8 | 262.6 | 209.4 | 11,116 | 12,141 | 11,938 | 784 | 748 | 830 | 278.3 | 339.9 | 285.9 |
| Horseshoe Canyon | 54.6 | 58.4 | 61.2 | 5 | 6 | 8 | — | — | — | 54.6 | 58.5 | 61.2 |
| Horn River | 27.1 | 14.1 | 8.0 | — | — | — | — | — | — | 27.1 | 14.1 | 8.0 |
| Canada | 81.7 | 72.5 | 69.2 | 5 | 6 | 8 | — | — | — | 81.7 | 72.6 | 69.2 |
| Consolidated | 288.5 | 335.1 | 278.6 | 11,121 | 12,147 | 11,946 | 784 | 748 | 830 | 360.0 | 412.5 | 355.1 |

Average Realized Price by operating area:

| | Natural Gas | | | NGL | | | Oil | | | Equivalent Total | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 |
| | (per Mcf) | | | (per Bbl) | | | (per Bbl) | | | (per Mcfe) | | |
| Barnett Shale | $ 2.66 | $ 3.94 | $ 4.23 | $ 33.87 | $ 48.98 | $ 36.93 | $ 89.85 | $ 91.83 | $ 74.71 | $ 3.47 | $ 4.92 | $ 4.80 |
| Other U.S. | 2.59 | 4.06 | 4.16 | 50.83 | 72.92 | 56.04 | 83.13 | 84.87 | 68.77 | 11.57 | 11.65 | 8.68 |
| Hedging | 2.00 | 1.05 | 3.28 | 5.77 | (10.41) | (5.53) | — | — | — | 1.72 | 0.44 | 2.17 |
| U.S. | $ 4.66 | $ 4.99 | $ 7.51 | $ 39.67 | $ 38.61 | $ 31.44 | $ 85.98 | $ 88.15 | $ 71.87 | $ 5.29 | $ 5.42 | $ 7.02 |
| Horseshoe Canyon | $ 2.41 | $ 3.71 | $ 5.06 | $ 61.12 | $ 64.64 | $ 66.03 | $ — | $ — | $ — | $ 2.41 | $ 3.72 | $ 5.07 |
| Horn River | 2.40 | 3.39 | 3.64 | — | — | — | — | — | — | 2.41 | 3.39 | 3.64 |
| Hedging | 0.66 | 1.16 | 0.90 | — | — | — | — | — | — | 0.66 | 1.16 | 0.90 |
| Canada | $ 3.07 | $ 4.81 | $ 4.90 | $ 67.91 | $ 64.64 | $ 66.03 | $ — | $ — | $ — | $ 3.07 | $ 4.82 | $ 4.90 |
| Consolidated production revenue | $ 4.21 | $ 4.95 | $ 6.86 | $ 39.69 | $ 38.63 | $ 31.46 | $ 85.98 | $ 88.15 | $ 71.90 | $ 4.79 | $ 5.32 | $ 6.61 |
| U.S. realized cash derivative gains | $ 0.30 | — | — | — | — | — | — | — | — | $ 0.23 | — | — |
| Canada realized cash derivative gains | 0.66 | — | — | — | — | — | — | — | — | 0.66 | — | — |
| Consolidated realized cash derivative gains | 0.41 | — | — | — | — | — | — | — | — | 0.32 | — | — |
| Consolidated production revenue and realized cash derivative gains | $ 4.62 | $ 4.95 | $ 6.86 | $ 39.69 | $ 38.63 | $ 31.46 | $ 85.98 | $ 88.15 | $ 71.90 | $ 5.11 | $ 5.32 | $ 6.61 |

The following table summarizes the changes in our natural gas, NGL and oil production revenue and realized cash derivative gains (losses):

| | Natural Gas | NGL | Oil | Total |
|---|---|---|---|---|
| | (In thousands) | | | |
| Production Revenue for 2010 | $ 697,413 | $ 137,161 | $ 21,775 | $ 856,349 |
| Volume variances | 86,142 | 2,727 | (2,140) | 86,729 |
| Hedge settlement variances | (142,014) | (22,033) | — | (164,047) |
| Price variances | (36,336) | 53,410 | 4,438 | 21,512 |
| Production Revenue for 2011 | $ 605,205 | $ 171,265 | $ 24,073 | $ 800,543 |
| Volume variances | (64,614) | (17,820) | 1,235 | (81,199) |
| Hedge settlement variances | 40,171 | 69,602 | — | 109,773 |
| Price variances | (136,048) | (61,505) | (617) | (198,170) |
| Production Revenue for 2012 | $ 444,714 | $ 161,542 | $ 24,691 | $ 630,947 |
| Realized cash derivative variance (1) | 42,799 | — | — | 42,799 |
| Production Revenue and Realized cash derivative gains | $ 487,513 | $ 161,542 | $ 24,691 | $ 673,746 |

(1) This amount is also included in the production revenue and realized cash derivatives gains table above.

Natural gas and NGL revenue for 2012 decreased from 2011 as a result of a decrease in both realized prices without hedging gains and production. The decrease in natural gas volume from our Barnett Shale Asset was primarily due to production declines resulting from the aging of existing wells and a reduction of our capital program related to our Barnett Shale Asset. On a lesser basis, natural gas production volumes were also impacted by temporary shut-ins in support of new development activity.

Natural gas revenue for 2011 decreased from 2010 despite a 20% increase in production. Realized prices, before hedge settlements, were lower for 2011 as compared to 2010, which more than offset production increases. The 2011 increase in natural gas volume from our Barnett Shale Asset was primarily the result of additional producing wells in our Alliance Asset to meet our Eni commitment as well as production throughout the basin up-lift from well work over activity. The Canadian natural gas production increase was primarily the result of two additional producing wells in our Horn River Asset that were brought on line in December 2010. The decrease in our Horseshoe Canyon Asset production was the result of reduced capital spending and the aging of the field.

The increase in NGL revenue for 2011 resulted from an increase in both realized prices and in production primarily from our Barnett Shale Asset compared to 2010. The increase in production resulted from additional producing wells and work over activity in the southern portion of the basin.

*Sales of Purchased Natural Gas and Costs of Purchased Natural Gas*

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | | (In thousands) | |
| Sales of purchased natural gas: | | | |
| Purchases from Eni | $ 58,881 | $ 71,921 | $ 53,340 |
| Purchases from others | 3,524 | 14,724 | 10,749 |
| Total | 62,405 | 86,645 | 64,089 |
| Costs of purchased natural gas sold: | | | |
| Purchases from Eni | 58,915 | 71,746 | 61,121 |
| Purchases from others | 3,126 | 13,652 | 10,825 |
| Unrealized valuation gain on Gas Purchase Commitment | — | — | (6,625) |
| Total | 62,041 | 85,398 | 65,321 |
| Net sales and purchases of natural gas | $ 364 | $ 1,247 | $ (1,232) |

We purchase Eni's interest in natural gas production in our Alliance Asset and then sell the natural gas to others. The decrease from 2012 compared to 2011 is due to decreased production primarily as a result of fewer new wells brought online in 2012 and lower realized prices. As the Gas Purchase Commitment with Eni expired on December 31, 2010, no unrealized valuation gain or loss was recognized for 2011 or 2012.

*Derivative Gains (Losses), net*

The following table summarizes our net derivative gains and losses:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | | (In thousands) | |
| Unrealized mark-to-market changes in fair value of natural gas derivative gains (losses) (1) | $ (17,880) | $ 45,852 | $ — |
| Realized cash settlements of natural gas derivative gains | 42,798 | — | — |
| Non-cash loss in fair value from restructured natural gas derivatives | (14,755) | — | — |
| Gain (loss) from hedge ineffectiveness | 1,281 | 5,928 | (2,629) |
| Derivative gains (losses), net | 11,444 | 51,780 | (2,629) |

(1) Unrealized mark-to-market changes in fair value are subject to continuing market risk.

In 2012 we began to account for the fair value changes of certain natural gas derivatives in the income statement as reflected in the above table and discussed earlier in the Overview of Quarter Restatement. In 2012, we terminated a number of our ten-year derivative instruments in exchange for derivative instruments with shorter durations at above market terms. The decrease in the fair value between the terminated ten -year instrument and the new shorter term instrument was recognized as a non-cash loss in fair value from restructured derivatives. Unrealized mark-to-market gains for 2011 is due to our recognition of $48.9 million for unrealized gains on commodity derivatives that were not designated as hedges at inception. These instruments were subsequently designated as hedges in August 2011 with unrealized gains and losses from that date forward recognized as a component of AOCI. These unrealized gains were partially offset by a decrease in fair value of the related hedge assets due to credit risk of our counterparties as of December 31, 2011.

*Other Revenue*

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | | (In thousands) | |
| Midstream revenue from third parties: | | | |
| KGS | $ — | $ — | $ 6,512 |
| Canada | 2,523 | 3,139 | 2,373 |
| Texas | 1,687 | 1,018 | 1,352 |
| Total midstream revenue | 4,210 | 4,157 | 10,237 |
| Other | 32 | 498 | 285 |
| Total | $ 4,242 | $ 4,655 | $ 10,522 |

U.S. midstream revenue declined in 2011 primarily as a result of the sale of our interests in KGS in October 2010 and a decrease in volumes gathered in our HCDS (which contributed to the 2011 impairment more fully discussed elsewhere in these results of operations). The increase in Canada was primarily the result of additional customers under contract for the transportation of natural gas.

**Operating Expense**

*Lease Operating Expense*

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2012 | | 2011 | | 2010 | |
| | (In thousands, except per unit amounts) | | | | | |
| | | Per Mcfe | | Per Mcfe | | Per Mcfe |
| Barnett Shale | | | | | | |
| Cash expense | $ 53,509 | $ 0.53 | $ 62,158 | $ 0.50 | $ 47,231 | $ 0.46 |
| Equity compensation | 997 | 0.01 | 904 | 0.01 | 841 | 0.01 |
| | $ 54,506 | $ 0.54 | $ 63,062 | $ 0.51 | $ 48,072 | $ 0.47 |
| Other U.S. | | | | | | |
| Cash expense | $ 8,317 | $ 6.49 | $ 6,327 | $ 5.24 | $ 5,945 | $ 4.05 |
| Equity compensation | 166 | 0.13 | 224 | 0.19 | 182 | 0.12 |
| | $ 8,483 | $ 6.62 | $ 6,551 | $ 5.43 | $ 6,127 | $ 4.17 |
| Total U.S. | | | | | | |
| Cash expense | $ 61,826 | $ 0.61 | $ 68,485 | $ 0.55 | $ 53,176 | $ 0.51 |
| Equity compensation | 1,163 | 0.01 | 1,128 | 0.01 | 1,023 | 0.01 |
| | $ 62,989 | $ 0.62 | $ 69,613 | $ 0.56 | $ 54,199 | $ 0.52 |
| Horseshoe Canyon | | | | | | |
| Cash expense | $ 29,107 | $ 1.46 | $ 29,853 | $ 1.40 | $ 27,221 | $ 1.21 |
| Equity compensation | 375 | 0.02 | 461 | 0.02 | 1,271 | 0.06 |
| | $ 29,482 | $ 1.48 | $ 30,314 | $ 1.42 | $ 28,492 | $ 1.27 |
| Horn River | | | | | | |
| Cash expense | $ 2,862 | $ 0.29 | $ 2,947 | $ 0.57 | $ 2,145 | $ 0.74 |
| Equity compensation | — | — | — | — | — | — |
| | $ 2,862 | $ 0.29 | $ 2,947 | $ 0.57 | $ 2,145 | $ 0.74 |
| Total Canada | | | | | | |
| Cash expense | $ 31,969 | $ 1.07 | $ 32,800 | $ 1.24 | $ 29,366 | $ 1.16 |
| Equity compensation | 375 | 0.01 | 461 | 0.02 | 1,271 | 0.05 |
| | $ 32,344 | $ 1.08 | $ 33,261 | $ 1.26 | $ 30,637 | $ 1.21 |
| Total Company | | | | | | |
| Cash expense | $ 93,795 | $ 0.71 | $ 101,285 | $ 0.67 | $ 82,542 | $ 0.63 |
| Equity compensation | 1,538 | 0.01 | 1,589 | 0.01 | 2,294 | 0.02 |
| | $ 95,333 | $ 0.72 | $ 102,874 | $ 0.68 | $ 84,836 | $ 0.65 |

Lease operating expense for 2012 on a gross basis in the U.S. decreased compared to 2011 primarily due to the Barnett Shale Asset experiencing lower gas lift costs, workover expenses and saltwater disposal costs compared to 2011 through continued cost containment initiatives. On a per Mcfe basis the Barnett Shale Asset lease operating expense increased due to production decreases during the year. Other U.S. lease operating costs were impacted on a gross and unit basis by increased production and costs for our Niobrara Asset. In Canada, lease operating expense for 2012 decreased compared to 2011 due to lower well and compressor repair and maintenance costs and lower labor costs incurred during 2012.

Lease operating expense for 2011 in the U.S. increased compared to 2010 primarily due to higher production volumes in our Barnett Shale Asset, including costs attributable to new producing wells such as gas lift, chemicals and overhead of approximately $8 million. In addition, non-variable costs such as compressor overhauls, repairs and replacements, environmental compliance and other costs increased by approximately $7 million. Notably, saltwater disposal costs increased only slightly despite a 16% increase in water volumes due to a higher percentage being piped and disposed of in our own disposal wells at a lower cost.

In 2011 our Horseshoe Canyon Asset lease operating expense increased primarily due to increases in compression overhauls, utilities and surface costs. Notably, costs per Mcfe in our Horn River Asset decreased as a consequence of increased production levels creating greater coverage of the fixed portion of expense.

*Gathering, Processing and Transportation Expense*

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2012 | | 2011 | | 2010 | |
| | (In thousands, except per unit amounts) | | | | | |
| | | Per Mcfe | | Per Mcfe | | Per Mcfe |
| Barnett Shale | $ 141,269 | $ 1.40 | $ 172,128 | $ 1.40 | $ 82,976 | $ 0.81 |
| Other U.S. | 13 | 0.01 | 70 | 0.05 | 22 | 0.01 |
| Total U.S. | $ 141,282 | $ 1.39 | $ 172,198 | $ 1.39 | $ 82,998 | $ 0.80 |
| Horseshoe Canyon | 3,547 | 0.18 | 4,157 | 0.19 | 4,867 | 0.22 |
| Horn River | 21,487 | 2.16 | 14,205 | 2.77 | 6,143 | 2.11 |
| Total Canada | 25,034 | 0.84 | 18,362 | 0.69 | 11,010 | 0.44 |
| Total | $ 166,316 | $ 1.26 | $ 190,560 | $ 1.27 | $ 94,008 | $ 0.73 |

U.S. GPT decreased in total for 2012 compared to 2011 primarily due to lower production volume from the Barnett Shale Asset. Canadian GPT increased both in total dollars and on a per Mcfe basis primarily as a result of fixed costs under our firm agreements with third parties in our Horn River Asset. Canadian GPT includes unused firm capacity of $6.7 million and $4.6 million for 2012 and 2011, respectively. The Horn River Asset decrease on a per Mcfe basis is primarily attributable to increased production during 2012.

GPT for 2011 compared to 2010 increased primarily due to the loss of fees earned by KGS for gathering and processing production from our Barnett Shale Asset following the closing of the Crestwood Transaction and the increase in our Barnett Shale Asset production. KGS' revenue, net of associated operating expenses, was $72.9 million, or 0.71 per Mcfe, for 2010. The remainder of the increase is attributable to increases in production although unit costs were lower in 2010 (excluding KGS effects) because more production came from the northern portion of the basin. Canadian GPT increased for 2011 as compared to 2010 both in total dollars and on a per Mcfe basis primarily as a result of higher gathering fees and increased production from our Horn River Asset for 2011 and the recognition of $4.6 million for unutilized capacity under the Company's firm transportation agreements with third parties. The decrease in our Horseshoe Canyon Asset is primarily due to reduced transportation fees and a decrease in production volumes. Our Horseshoe Canyon Asset GPT also decreased due to reduced operating costs on gathering lines which feature cost sharing arrangements.

*Production and Ad Valorem Taxes*

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2012 | | 2011 | | 2010 | |
| | (In thousands, except per unit amounts) | | | | | |
| | | Per Mcfe | | Per Mcfe | | Per Mcfe |
| Production taxes | | | | | | |
| Barnett Shale | $ 4,982 | $ 0.05 | $ 7,886 | $ 0.06 | $ 8,184 | $ 0.08 |
| Other U.S. | 857 | 0.67 | 1,097 | 0.91 | 987 | 0.67 |
| Total U.S. | 5,839 | 0.06 | 8,983 | 0.07 | 9,171 | 0.09 |
| Horseshoe Canyon | 167 | 0.01 | 231 | 0.01 | 609 | 0.03 |
| Horn River | — | — | — | — | — | — |
| Total Canada | 167 | 0.01 | 231 | 0.01 | 609 | 0.03 |
| Total production taxes | 6,006 | 0.05 | 9,214 | 0.06 | 9,780 | 0.07 |
| Ad valorem taxes | | | | | | |
| Barnett Shale | $ 15,963 | $ 0.16 | $ 16,875 | $ 0.14 | $ 21,592 | $ 0.21 |
| Other U.S. | 470 | 0.37 | 220 | 0.18 | 205 | 0.14 |
| Total U.S. | 16,433 | 0.16 | 17,095 | 0.14 | 21,797 | 0.21 |
| Horseshoe Canyon | 2,696 | 0.13 | 2,850 | 0.13 | 2,549 | 0.11 |
| Horn River | 260 | 0.03 | 67 | 0.01 | 30 | 0.02 |
| Total Canada | 2,956 | 0.10 | 2,917 | 0.11 | 2,579 | 0.10 |
| Total ad valorem taxes | 19,389 | 0.15 | 20,012 | 0.13 | 24,376 | 0.19 |
| Total | $ 25,395 | $ 0.19 | $ 29,226 | $ 0.19 | $ 34,156 | $ 0.26 |

Production taxes in the U.S. decreased in 2012 primarily as a result of decreased volumes while the decrease on a per Mcfe basis is a result of decreased prices compared to 2011.

U.S. production taxes for 2011 reflect the refund of 2008 severance taxes in the amount of $1.1 million. The decrease in Canadian production taxes from 2010 to 2011 is primarily the result of decreased volumes attributable to freehold acreage, which is subject to taxation, and due to decreased pricing upon which tax is levied. The decrease in 2011 U.S. ad valorem taxes as compared to 2010 is primarily the result of the sale of KGS, attributing $3.8 million to the decrease. The remaining approximately $1 million decrease is attributable to reduced assessed property values as a function of lower prices. The increase in 2011 Canadian ad valorem taxes is due to increased rates on freehold lands and an increase in the midstream property base.

*Depletion, Depreciation and Accretion*

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2012 | | 2011 | | 2010 | |
| | (In thousands, except per unit amounts) | | | | | |
| | | Per Mcfe | | Per Mcfe | | Per Mcfe |
| Depletion | | | | | | |
| U.S. | $ 116,005 | $ 1.14 | $ 164,493 | $ 1.33 | $ 129,843 | $ 1.24 |
| Canada | 24,897 | 0.83 | 38,228 | 1.44 | 38,825 | 1.54 |
| Total depletion | 140,902 | 1.07 | 202,721 | 1.35 | 168,668 | 1.30 |
| Depreciation of other fixed assets: | | | | | | |
| U.S. | $ 8,913 | $ 0.09 | $ 12,931 | $ 0.10 | $ 30,252 | $ 0.29 |
| Canada | 9,687 | 0.32 | 7,415 | 0.28 | 4,698 | 0.19 |
| Total depreciation | 18,600 | 0.14 | 20,346 | 0.14 | 34,950 | 0.27 |
| Accretion | 4,122 | 0.03 | 2,696 | 0.02 | 3,585 | 0.03 |
| Total | $ 163,624 | $ 1.24 | $ 225,763 | $ 1.50 | $ 207,203 | $ 1.60 |

U.S. depletion expense for 2012 decreased from 2011 as production decreased in addition to a decreased depletion rate. Canadian depletion expense remained consistent due to increased production partially offset by a rate decrease. Both our U.S. and Canadian depletion rates have been impacted by the impairment charges recognized during 2012. We expect that our U.S. and Canadian depletion rate for 2013 will be approximately $0.52 and $0.14 per Mcfe, respectively.

The decrease in 2012 U.S. depreciation expense as compared to 2011 is the result of midstream impairments from 2011. The Canadian depreciation expense increased in 2012 compared to 2011 as a result of additions of other fixed assets in support of our increased activity in the Horn River Asset.

U.S. depletion for 2011 reflected an increase in the U.S. depletion rate and an increase in U.S. production when compared to the 2010 period. The increase in the rate was due to a 7% decrease in reserves and an increase in the depletion base associated with our 2011 capital program. Price deterioration adversely affected reserves in 2011. Canadian depletion rate in 2011 was impacted by the impairment recognized in 2011 as the 24% increase in proved reserves resulted in only a 8% increase in the depletion base.

U.S. depreciation decreased in 2011 from 2010 primarily as the result of 2010 including KGS depreciation of $15.9 million and a $55.0 million impairment of midstream assets. Canadian depreciation for 2011 reflects seven months of depreciation on our Horn River Asset midstream additions which were contributed in the formation of Fortune Creek.

*Impairment Expense*

As required under GAAP, we perform quarterly ceiling tests to assess impairment of our oil and gas properties. We also assess our fixed assets reported outside the full-cost pool when circumstances indicate impairment may have occurred. Information detailing the calculation of any impairment is more fully described in our "Critical Accounting Policies" found below and in Note 8 to the consolidated financial statements in Item 8 of this Annual Report.

In 2012, we recognized non-cash charges of $2.2 billion and $465.9 million for our U.S. and Canadian oil and gas properties, respectively, as a result of our quarterly ceiling tests. The natural gas and natural gas liquids pricing used in our quarterly ceiling tests declined throughout the year resulting in impairment charges being recognized in each quarter. Additionally, effective December 31, 2012, we no longer account for derivatives as hedges and therefore our year-end ceiling test did not include this benefit. In performing our quarterly ceiling tests, we utilize the average first of month prices for the preceding 12 months. We do not anticipate additional impairment related to our oil and gas properties in 2013 as natural gas prices in 2013 are forecasted to be improved compared to 2012.

We recognized impairment expense on other property and equipment of $7.9 million, including $7.3 million on pipelines and processing facilities located in Colorado and Texas as a result of reduced utilization and lower reserves. We also impaired general properties $0.6 million related to reduced utilization of a compressed natural gas station in Texas.

We recognized a $49.1 million non-cash charge for impairment of our Canadian oil and gas properties in 2011. The AECO natural gas price used to prepare the March 31, 2011 estimate of the ceiling limit for our Canadian full-cost pool decreased approximately 12% from the AECO price used at December 31, 2010 when we also recognized an impairment charge for our Canadian oil and gas properties. Our Canadian ceiling test prepared at June 30, 2011, September 30, 2011 and December 31, 2011 resulted in no additional impairment of our Canadian oil and gas properties. Our U.S. ceiling tests, prepared quarterly, resulted in no impairment of our U.S. oil and gas properties in 2011.

In 2011, we recognized a $44.7 million impairment for certain midstream assets in Texas that we retained after the sale of KGS. The primary factors for the impairment were our inability to attract third-party customers to utilize the pipe and a decrease in reserves from our assets that utilize the laterals. During 2011, we discontinued our efforts to actively market the HCDS assets and recognized additional impairment of HCDS. We conducted an impairment analysis of the HCDS and recorded $13.3 million during 2011 to reduce the carrying value to estimated fair value.

In 2010, we recognized impairment expense of $48.0 million. As a result of the decision by our board of directors to approve a plan for disposal of our HCDS, we conducted an impairment analysis of the HCDS and recognized a $28.6 million non-cash charge for impairment. We also recognized a non-cash $19.4 million charge for impairment of our Canadian oil and gas properties. Our Canadian full-cost pool has undergone significant change associated with the cost of bringing our initial Horn River Asset wells online and associated field costs while the proved reserves recognized had been limited due to the lack of any substantial production history for the area.

*General and Administrative Expense*

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2012 | | 2011 | | 2010 | |
| | (In thousands, except per unit amounts) | | | | | |
| | | Per Mcfe | | Per Mcfe | | Per Mcfe |
| Equity compensation | $ 20,709 | $ 0.16 | $ 19,272 | $ 0.13 | $ 22,144 | $ 0.17 |
| Audit and accounting fees | 6,179 | 0.05 | 1,216 | 0.01 | 1,132 | 0.01 |
| Strategic transactions | 8,503 | 0.06 | 4,978 | 0.03 | 4,746 | 0.04 |
| Litigation settlement | — | — | 8,500 | 0.06 | 2,650 | 0.02 |
| Other | 40,306 | 0.31 | 45,616 | 0.30 | 49,435 | 0.38 |
| Total | $ 75,697 | $ 0.58 | $ 79,582 | $ 0.53 | $ 80,107 | $ 0.62 |

General and administrative expense for 2012 was $3.9 million lower than 2011 due to a decrease in litigation settlement expense and strategic transaction costs during the year. These decreases were partially offset by an increase in our audit fees incurred related to our 2011 audit and an increase in our equity compensation during the year due to accelerated stock compensation expense in connection with a previously announced executive retirement. In 2012, we recognized expense of $7.2 million related to previously deferred filing fees for our Barnett Shale Asset master limited partnership since the transaction has been dormant since June 2012. The recognition of these fees in 2012 does not preclude us from continuing the offering process. We expect our audit fees to return to more typical levels in 2013.

General and administrative costs for the 2011 period included $8.5 million for litigation settlement and $5.0 million for legal, accounting and professional fees incurred in connection with the evaluation of possible strategic transactions. General and administrative expense for the 2010 period included costs for the settlement of a separate legal matter for $2.4 million, professional and legal fees incurred in connection with the Crestwood Transaction of $2.6 million plus $5.0 million of KGS general and administrative expense arising prior to the Crestwood Transaction.

*Gain on Sale of KGS*

In October 2010, we recognized a $494.0 million gain upon closing of the Crestwood Transaction. Further information regarding the transaction can be found in Note 3 to our consolidated financial statements included in Item 8 of this Annual Report.

*Crestwood Earn-Out*

In February 2012, we collected $41 million of earn-out payments from Crestwood. We will not receive any additional payment in 2013.

**Income from Earnings of BBEP**

We recorded our portion of BBEP's earnings during the quarter in which its financial statements became publicly available. As a result, our 2011 and 2010 annual results of operations included BBEP's earnings for the 12 months ended September 30, 2011 and 2010, respectively. We reduced our ownership of BBEP Units in 2010 and eliminated our remaining ownership position in 2011. As of December 31, 2011, we no longer owned any BBEP Units.

We recognized an $8.4 million loss and income of $22.3 million for equity earnings from our investment in BBEP based upon its reported earnings for the 12-month periods ended September 30, 2011 and 2010, respectively. During the time we owned BBEP Units, BBEP experienced significant volatility in its net earnings primarily due to changes in the value of its derivative instruments for which it did not employ hedge accounting.

**Other Income**

We recognized gains of $217.9 million in 2011 from the sale of 15.7 million BBEP Units. We also recognized a gain of $35.4 million from the conveyance of 3.6 million BBEP Units as consideration in the acquisition of additional working interests in our Lake Arlington Asset in May 2010. Gains totaling $22.2 million were recognized in September and October 2010 from the sale of 2.05 million BBEP Units. In 2010, we also finalized a settlement of our litigation with BBEP and received $18.0 million from BBEP and a third party. Note 3 to the consolidated financial statements found in this Annual Report contains additional information about the Lake Arlington transaction.

**Fortune Creek Accretion**

In December 2011, we and KKR formed a midstream partnership to construct and operate natural gas midstream assets to support producer customers in British Columbia. In connection with the partnership formation, KKR contributed $125 million cash in exchange for a 50% interest in Fortune Creek. KKR's contribution is shown as Partnership liability in the condensed consolidated balance sheet, and we recognize accretion expense to reflect the rate of return earned by KKR via its investment.

**Interest Expense**

| | Years Ended December 31, 2012 | 2011 | 2010 |
|---|---|---|---|
| | | (In thousands) | |
| Interest costs on debt outstanding | $ 172,502 | $ 172,696 | $ 174,906 |
| Add: | | | |
| Fees paid on letters of credit outstanding | 118 | 1,674 | 971 |
| Cash premium on early debt extinguishment | — | 2,560 | — |
| Non-cash interest [(1)] | 9,854 | 16,510 | 17,226 |
| Total interest cost incurred | 182,474 | 193,440 | 193,103 |
| Less: | | | |
| Interest capitalized | (18,423) | (7,416) | (4,750) |
| Interest expense | $ 164,051 | $ 186,024 | $ 188,353 |

(1) Amortization of deferred financing costs and original issue discount.

Interest costs on debt outstanding for 2012 were flat compared to 2011. 2012 non-cash interest decreased as a result of lower deferred financing costs compared to 2011. Interest capitalized in 2012 increased compared to 2011 as unevaluated property balances increased primarily in our Niobrara Asset and West Texas Asset. As of December 31, 2012, we have moved our Niobrara Asset to the full cost pool and will no longer capitalize interest on these costs.

Interest costs on debt outstanding for 2011 were flat compared to 2010. 2011 included slightly higher credit facility borrowing offset by lower senior debt and convertible debentures which offset the overall level of interest expense on all debt. 2011 included non-cash interest attributable to the repurchased senior notes and deferred financing fees attributable to the terminated 2007 Senior Secured Credit Facility and the Initial U.S Credit Facility. 2010 included interest expense attributable to KGS of $6.9 million in 2010.

In 2011, we repurchased notes as summarized below:

| Instrument | Repurchase Price | Face Value | Premium on Repurchase |
|---|---|---|---|
| | | (In thousands) | |
| Senior notes due 2015 | $ 38,134 | $ 37,000 | $ 1,134 |
| Senior notes due 2016 | 10,646 | 9,380 | 1,266 |
| Senior notes due 2019 | 2,160 | 2,000 | 160 |
| | $ 50,940 | $ 48,380 | $ 2,560 |

**Income Taxes**

The U.S effective tax rates for the three years ended December 31, 2012 are as follows:

| | Years Ended December 31, 2012 | 2011 | 2010 |
|---|---|---|---|
| | | (In thousands) | |
| Income (loss) before income taxes | $ (2,142,730) | $ 146,090 | $ 708,081 |
| Income tax expense (benefit) | $ (227,913) | $ 53,599 | $ 255,207 |
| Effective tax rate | 10.64% | 36.69% | 36.04% |

In 2012, our U.S. income tax expense includes a valuation allowance of $534.0 million, which when excluded from our U.S. effective tax rate results in an adjusted tax rate of 35.6% which is comparable to our statutory rate discussed below.

The Canadian effective tax rates for the three years ended December 31, 2012 are as follows:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | | (In thousands) | |
| Income (loss) before income taxes | $ (505,446) | $ 1,819 | $ 5,747 |
| Income tax expense (benefit) | $ (67,657) | $ 4,264 | $ 3,331 |
| Effective tax rate | 13.39% | 234.41% | 57.96% |

In 2012, our Canadian income tax expense includes a valuation allowance of $61.3 million, which when excluded from our Canadian effective tax rate results in an adjusted tax rate of 25.5% which is comparable to our statutory rate discussed below.

The consolidated effective tax rates for the three years ended December 31, 2012 are as follows:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | | (In thousands) | |
| Income (loss) before income taxes | $ (2,648,176) | $ 147,909 | $ 713,828 |
| Income tax expense (benefit) | $ (295,570) | $ 57,863 | $ 258,538 |
| Effective tax rate | 11.16% | 39.12% | 36.22% |

In 2012, our consolidated income tax expense includes a valuation allowance of $595.3 million, which when excluded from our consolidated effective tax rate results in an adjusted tax rate of 33.6%.

Taxation in the U.S. for the three years utilized a federal tax rate of 35% and a state tax rate of 1%. Actual effective tax rates excluding valuation allowance differed from the combined U.S. and state rates primarily as a result of permanent items related to the non-deductible expenses.

The Canadian effective tax rates for the three years utilized a combined federal and provincial rate of 25%. The increase in the Canadian effective rate for 2011 was the result of an audit assessment imposed during 2011 and the application of capital gains rates related to the formation of Fortune Creek.

During 2012, we recognized a U.S. and Canadian valuation allowance of $534.0 million and $61.3 million, respectively, as we determined that it is no longer more likely than not that we will realize the deferred tax benefits primarily related to our cumulative net operating losses because we have been in a cumulative three-year loss for both the U.S. and Canada. For 2012, our effective rate in the U.S. was 35.6% and in Canada, it was 25.5%.

Our income tax provision for 2011 decreased from the income tax provision recognized for 2010, primarily as a result of the decrease in pretax earnings. The 2010 pretax earnings included the gain on the sale of KGS. Canadian taxes increased for 2011 due to the recognition of capital gain resulting from the formation of Fortune Creek. For 2011, our effective rate in the U.S. was 36.7% and in Canada, it was 234.4%.

**Quicksilver Resources Inc. and its Restricted Subsidiaries**

Information about Quicksilver and our restricted and unrestricted subsidiaries is included in Note 19 to our consolidated financial statements included in Item 8 in this Annual Report.

The combined results of operations for Quicksilver and our restricted subsidiaries are substantially similar to our consolidated results of operations, which are discussed above under *"Results of Operations."* The combined financial position of Quicksilver and our restricted subsidiaries and our consolidated financial position are materially the same except for the property, plant and equipment purchased by the unrestricted subsidiaries, which prior to October 1, 2010 consisted of KGS and its subsidiaries, and the balances held by Fortune Creek, which were included in the consolidated financial position as of December 31, 2012. The combined operating cash flows, financing cash flows and investing cash flows for Quicksilver and our restricted subsidiaries are substantially similar to our consolidated operating cash flows, financing cash flows and investing cash flows, which are discussed below in "Cash Flow Activity."

## LIQUIDITY, CAPITAL RESOURCES AND FINANCIAL POSITION

### Cash Flow Activity

*Operating Cash Flows*

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | (In thousands) | | |
| Net cash provided by operating activities | $ 227,727 | $ 253,053 | $ 397,720 |

Net cash provided by operations for 2012 decreased from 2011, primarily due to lower realized prices (including hedging effects) and lower production volumes partially offset by positive changes in working capital.

Net cash provided by operations for 2011 decreased from 2010, primarily due to higher net payments to CMLP for GPT costs of $97 million and a $56 million decrease in production revenue due to our lower realized prices, partially offset by $18 million in settlement of litigation in 2010.

*Investing Cash Flows*

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | (In thousands) | | |
| Purchases of property, plant and equipment | $ (485,479) | $ (690,607) | $ (695,114) |
| Proceeds from sale of KGS | — | — | 699,973 |
| Proceeds from Crestwood earn-out | 41,097 | — | — |
| Proceeds from sale of BBEP units | — | 272,965 | 34,016 |
| Proceeds from sales of properties & equipment | 72,725 | 4,163 | 9,953 |
| Net cash provided (used) by investing activities | $ (371,657) | $ (413,479) | $ 48,828 |

For each of the three years in the period ended December 31, 2012, we have spent significant cash resources for the development of our large acreage positions in our core areas in the Barnett Shale and Horn River. During 2012, we collected $41.1 million from Crestwood pursuant to the earn-out provisions of our agreement with them, and received a confidential equalization payment upon closing of the SWEPI transaction. During 2011, we sold 15.7 million BBEP Units for an average price of $17.40 or total proceeds of $273.0 million that was used to repay borrowings outstanding under our senior secured credit facilities. During 2010, we sold 2.0 million BBEP Units at an average price of $16.70 or total proceeds of $34.0 million and completed the Crestwood Transaction with net cash proceeds of $700 million after transaction costs.

Costs incurred reflect the true nature of the activity of the 2012 capital program, while capital expenditures shown in the consolidated statement of cash flows also reflect the related changes in working capital due to timing of actual invoice payments. Our 2012 capital costs incurred included 75% associated with direct drilling and completion activities, while 8% was spent for leasehold acquisitions and 3% spent for midstream activities. The majority of 2012 drilling and completion expenditures were associated with our Horn River and Barnett Shale Assets, but also included activity in our West Texas Asset and our Niobrara Asset. Leasehold expenditures reflected new acreage acquisitions and extensions in our Niobrara Asset and in our West Texas Asset. Midstream capital expenditures were concentrated in our Horn River Asset.

Our 2011 capital expenditures included 59% that was associated with drilling and completion activities, while 24% was spent for leasehold acquisitions and 11% spent for midstream activities. The majority of 2011 drilling and completion expenditures were associated with our Barnett Shale Asset, but also included increased activity in our Niobrara Asset and our Horn River Asset with expenditures of $36 million and $95 million, respectively. Leasehold expenditures reflected new acreage acquisitions in our Niobrara Asset of approximately $79 million and in our West Texas Asset of approximately $52 million. Midstream capital expenditures were concentrated in our Horn River Asset and principally related to the construction of the gathering system that was contributed in the formation of Fortune Creek.

The majority of the 2010 capital expenditures were associated with drilling, completion, and leasehold acquisition activity in the Barnett Shale which accounted for approximately 81% of such expenditures compared to only 45% in 2011.

*Financing Cash Flows*

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | | (In thousands) | |
| Net borrowings | $ 157,529 | $ 12,714 | $ (341,678) |
| Debt issuance costs | (3,022) | (12,506) | (3,111) |
| Partnership funds received (distributed) | (14,285) | 122,913 | — |
| Gas Purchase Commitment repayments | — | — | (44,119) |
| Issuance of KGS common units | — | — | 11,054 |
| Distributions paid on KGS common units | — | — | (13,550) |
| Proceeds from exercise of stock options | 11 | 1,299 | 1,801 |
| Taxes paid on vesting of KGS equity compensation | — | — | (1,144) |
| Excess tax benefits on exercise of stock options | — | — | 3,513 |
| Purchase of treasury stock | (3,144) | (4,864) | (4,910) |
| Net cash provided (used) by financing activities | $ 137,089 | $ 119,556 | $ (392,144) |

Net financing cash flows in 2012 include net borrowings of $157.5 million under our senior secured credit facilities, partially offset by $14.3 million of distributions from Fortune Creek. Net financing cash flows in 2011 include net borrowings of $227.5 million under our senior secured credit facilities and $122.9 million of funds received from Fortune Creek, partially offset by $48.4 million of purchases and retirement of our senior notes and repurchases of substantially all our $150 million convertible debentures. Financing cash flows in 2010 included $455 million to repay all outstanding balances on our 2007 Senior Secured Credit facility using a portion of the proceeds from the Crestwood Transaction. 2010 also included repayments of $44.1 million under the Gas Purchase Commitment.

*Liquidity and Borrowing Capacity*

In August 2012, in light of then prevailing prices for natural gas and NGLs, we amended our Combined Credit Agreements primarily to relax the financial covenants contained therein through the second quarter of 2014. The next semi-annual redetermination of our global borrowing base was scheduled to be completed in October 2012. However, in conjunction with the amendments to our Combined Credit Agreements, our global borrowing base was also redetermined and the next redetermination is scheduled for April 2013. We expect a reduction in the borrowing base from $850 million to approximately $550 million. As of February 28, 2013 we had approximately $490 million outstanding under our Combined Credit Agreements, including letters of credit. While we believe that the remaining availability of approximately $60 million together with operating cash flow will be adequate to meet our liquidity needs for the remainder of 2013, the borrowing base may be reduced below $550 million during the April or autumn redetermination or that amount may be insufficient to meet our liquidity needs. "2012 Highlights" contains additional information about the changes to our debt.

Our ability to remain in compliance with the financial covenants in our Combined Credit Agreements may be affected by events beyond our control. While we believe that we will be able to comply with these covenants through the end of 2013, we do not expect to exceed the required levels by a significant margin. Accordingly, even a modest decline in prices for natural gas and NGLs, our failure to achieve anticipated cost savings or the inaccuracy in any material respect of any of the other assumptions underlying our forecast could cause us to fail to comply with the covenants contained in the Combined Credit Agreements. In addition, absent an improvement in natural gas and NGL prices, significant deleveraging from a strategic transaction, reduced interest costs on our debt through refinancing or significant reductions to our operating costs, we expect to need to seek additional covenant relief under the Combined Credit Agreements for 2014. Any future inability to comply with these covenants, unless waived or amended by the requisite lenders, could materially and adversely affect our liquidity by rendering us unable to borrow further under our credit facilities and by accelerating the maturity of our debt.

We have an incurrence test under our indentures that requires EBITDA to exceed interest expense by 2.25 times. At December 31, 2012, we did not meet this test and, as a result, we are limited in our ability to, among other things, incur additional debt, except for specific baskets. We do retain, however, the ability to utilize the full borrowing capacity under our Combined Credit Agreements and our ability to refinance existing debt. Not meeting this ratio does not represent an event of default in our indentures. We are presently unable to predict when or if we will meet the incurrence test.

Additional information about our debt and related covenants is more fully described in Note 11 to the consolidated financial statements in Item 8 of this Annual Report.

We anticipate that our 2013 capital program will be substantially funded by cash flow from operations and could be further supplemented by proceeds from asset sales, although we could also borrow under the Combined Credit Agreements. If our capital resources are insufficient to fund our 2013 capital expenditure plan, we will need to reduce our capital expenditures or seek other financing alternatives. We may not be able to obtain financing needed in the future on terms that would be acceptable to us, or at all. If we limit or defer our 2013 capital expenditure plan, we could adversely affect the recoverability and ultimate value of our oil and gas properties.

We are currently pursuing joint venture partners in our Barnett Shale Asset and Horn River Asset. Any joint venture is likely to result in cash proceeds to us, a reduction in our capital expenditure and liquidity requirements or both.

Depending upon conditions in the capital markets and other factors, we will from time to time consider the issuance of debt or other securities or other possible capital markets transactions, the proceeds of which could be used to refinance current indebtedness or for other corporate purposes. We will also consider from time to time additional acquisitions of, and investments in, assets or businesses that complement our existing asset portfolio. Acquisition transactions, if any, are expected to be financed through cash flow from operations, borrowings under the Combined Credit Agreements, proceeds from asset sales, the issuance of debt or other securities or a combination of those sources.

To manage our exposure to commodity prices and to provide a level of certainty in the cash flows that will support our capital expenditure program, we hedge a portion of our production and, as of February 28, 2013, we had hedged approximately 200 MMcf per day of our estimated March through December 2013 natural gas production at a weighted average floor or swap price of $5.10 per Mcf.

*Financial Position*

The following impacted our balance sheet as of December 31, 2012, as compared to our balance sheet as of December 31, 2011:

- Our net property, plant and equipment balance decreased $2.4 billion from December 31, 2011 to December 31, 2012. We incurred capital expenditures of $390.5 million during 2012 and also recognized assets for retirement obligations established for new wells and facilities. DD&A, impairment expense and changes to U.S.-Canadian exchange rates reduced our property, plant and equipment balances $163.6 million, $2.6 billion and $8.9 million, respectively.
- The valuation of our current and non-current derivative assets and liabilities was $141.6 million lower on a net basis at December 31, 2012 as compared to December 31, 2011. The decrease was primarily the result of $263.6 million in settlements received partially offset by deferred unrealized gains of $110.6 million recognized in OCI.
- Long-term debt increased $159.8 million from net borrowings under our Combined Credit Agreements including exchange rate impacts.
- Our net deferred income tax position changed from a net liability position of $304.3 million to $0. Both the U.S. and Canada incurred losses in 2012 resulting in our deferred tax positions becoming a net deferred tax asset. We recorded a full valuation allowance on our deferred tax assets of $534.0 million and $61.3 million in the U.S. and Canada, respectively, as we determined a reduced likelihood of realizing deferred tax benefits primarily related to our cumulative net operating losses.

**Contractual Obligations and Commercial Commitments**

*Contractual Obligations*

Information regarding our contractual and scheduled interest obligations, at December 31, 2012, is set forth in the following table:

| | Payments Due by Period | | | | |
|---|---|---|---|---|---|
| | Total | Less than 1 Year | 1-3 Years | 4-5 Years | More than 5 Years |
| | | | (In thousands) | | |
| Long-term debt | $ 2,064,770 | $ — | $ 1,766,770 | $ — | $ 298,000 |
| Scheduled interest obligations | 624,328 | 174,432 | 378,599 | 54,385 | 16,912 |
| GPT contracts | 802,418 | 85,513 | 251,410 | 149,571 | 315,924 |
| Drilling rig contracts | 3,171 | 3,171 | — | — | — |
| Purchase obligations | 5,203 | 5,004 | 199 | — | — |
| Asset retirement obligations | 116,608 | 577 | 1,170 | 780 | 114,081 |
| Operating lease obligations | 39,299 | 4,723 | 13,276 | 10,123 | 11,177 |
| Total obligations | $ 3,655,797 | $ 273,420 | $ 2,411,424 | $ 214,859 | $ 756,094 |

- *Long-Term Debt.* As of December 31, 2012, our outstanding indebtedness included $438 million of senior notes due 2015, $591 million of senior notes due 2016, $298 million of senior notes due 2019, $350 million of senior subordinated notes, and outstanding amounts under our Combined Credit Agreements. Based upon our debt outstanding and interest rates as of December 31, 2012, we anticipate interest payments, including our scheduled interest obligations, to be $174.4 million in 2013.
- *Scheduled Interest Obligations.* As of December 31, 2012, we had scheduled interest payments of $36.1 million annually on our senior notes due 2015, $69.4 million annually on our senior notes due 2016, $27.2 million annually on our senior notes due 2019, $24.9 million annually on our $350 million of senior subordinated notes, and $16.8 million annually on our Combined Credit Agreements based on the amount outstanding and current rates.
- *Gathering, Processing and Transportation Contracts.* Under contracts with various third parties, we are obligated to provide minimum daily natural gas volume for gathering, processing, fractionation or transportation, as determined on a monthly basis, or pay for any volume deficiencies at a specified reservation fee rate.
- *Drilling Rig Contracts.* We utilize drilling rigs from third parties in our development and exploration programs. The outstanding drilling rig contracts, net of assignments, require payment of a specified day rate ranging from $6,005 to $12,500 for the entire lease term regardless of our utilization of the drilling rigs.
- *Purchase Obligations.* At December 31, 2012, we were under contract to purchase goods and services for use in field and gas plant operations.
- *Asset Retirement Obligations.* Our obligations result from the acquisition, construction or development and the normal operation of our long-lived assets.
- *Operating Lease Obligations.* We lease office buildings and other property under operating leases.

*Commercial Commitments*

We had the following commercial commitments as of December 31, 2012:

| | Amounts of Commitments by Expiration Period | | | | |
|---|---|---|---|---|---|
| | Total | Less than 1 Year | 1-3 Years | 4-5 Years | More than 5 Years |
| | | | (In thousands) | | |
| Surety bonds | $ 8,941 | $ 8,941 | $ — | $ — | $ — |
| Standby letters of credit | 60,820 | 60,820 | — | — | — |
| Total | $ 69,761 | $ 69,761 | $ — | $ — | $ — |

- *Surety Bonds.* Our surety bonds have been issued to fulfill contractual, legal or regulatory requirements. Surety bonds generally have an annual renewal option.
- *Standby Letters of Credit.* Our letters of credit have been issued to fulfill regulatory or contractual requirements including $29.8 million related to the Komie North Project as of December 31, 2012, but which was reduced to

$14 million during March 2013. All of these letters of credit were issued under our Combined Credit Agreements and generally have an annual renewal option.

*Project and Expenditure Authorization*

In September 2012, we amended the Project and Expenditure Authorization ("PEA") with NGTL, which supports the Komie North Project through our commitment for future delivery of gas from our Horn River Asset. In order to deliver gas that meets NGTL's specifications, we, through Fortune Creek, will construct a treatment facility for our gas. Under the amended PEA, we agreed to provide financial assurances to cover NGTL's after tax costs for the Komie North Project, estimated to be C $296.8 million, which is estimated to occur in stages based on NGTL's forecast of the Komie North Project costs, in the following cumulative amounts:

| | NGTL Cumulative Financial Assurances [1] | | |
|---|---|---|---|
| | (C$ in thousands) | | (US$ in thousands) |
| April 1, 2014 | 59,360 | $ | 59,663 |
| July 1, 2014 | 148,400 | $ | 149,157 |
| September 1, 2014 | 296,800 | $ | 298,314 |

(1) A letter of credit for C$29.7 million is outstanding for the Komie North Project as of December 31, 2012 which was reduced to C$14 million during March 2013.

The PEA also requires that we execute firm transportation agreements for delivery of a minimum volume of gas of approximately 100 Mmcfd, increasing to 300 Mmcfd, over a ten-year term commencing with the in-service date of the Komie North Project.

The PEA may be terminated prior to completion of the Komie North Project for various reasons, including the failure to obtain NEB approval upon terms and conditions satisfactory to NGTL. Based upon our current agreement with NGTL, which we expect may be amended as a result of the report of the NEB recommending against approval of the Komie North Project, we must pay actual costs incurred or paid by NGTL, or for which NGTL is liable, as of the termination date except in certain limited situations. If we do not amend the agreement and if termination occurs, we would pay those costs plus C$26.4 million with the option to purchase the project for an additional $1.

*Commitment Letter Agreement*

In April 2011, we entered into a Commitment Letter Agreement (the "Commitment Letter") with NGTL. Under the Commitment Letter, we agreed to deliver gas to NGTL beginning upon commissioning one of its pipelines. The obligation terminates on the earlier of NGTL's recovery of project costs or upon delivery of 1 Tcf cumulatively from us and any third-party producers. If neither has occurred by the end of the term of the transportation agreements, we will be required to renew the contract on an annual basis for a minimum volume of 106 Mmcfd until either the cost recovery or volume delivery requirements have been met. The Commitment Letter terminates if the PEA terminates for any reason other than the completion of the Komie North Project.

## CRITICAL ACCOUNTING ESTIMATES

Our consolidated financial statements are prepared in accordance with GAAP. In connection with the preparation of our financial statements, we are required to make assumptions and estimates about future events, and apply judgments that affect the reported amounts of assets, liabilities, revenue, expense and the related disclosures. We base our assumptions, estimates and judgments on historical experience, current trends and other factors that management believes to be relevant at the time we prepare our consolidated financial statements. On a regular basis, management reviews the accounting policies, assumptions, estimates and judgments to ensure that our financial statements are presented fairly and in accordance with GAAP. However, because future events and their effects cannot be determined with certainty, actual results could differ materially from our assumptions and estimates.

Our significant accounting policies are discussed in Note 2 to the consolidated financial statements included in Item 8 of this Annual Report. Management believes that the following accounting estimates are the most critical in fully understanding and evaluating our reported financial results, and they require management's most difficult, subjective or complex judgments, resulting from the need to make estimates about the effect of matters that are inherently uncertain. Management has reviewed these critical accounting estimates and related disclosures with our Audit Committee.

## Oil and Gas Reserves

*Policy Description*

Proved oil and gas reserves are the estimated quantities of oil, natural gas, and NGLs that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. We use an unweighted average of the preceding 12-month first-day-of-the-month prices for determination of proved reserve values included in calculating full cost ceiling limitations and for annual proved reserve disclosures. We assume continued use of technologies with demonstrated success of yielding expected results, including the use of drilling results, well performance, well logs, seismic data, geological maps, well stimulation techniques, well test data and reservoir simulation modeling.

Operating costs are the period end operating costs at the time of the reserve estimate and are held constant into future periods. Our estimates of proved reserves are determined and reassessed at least annually using available geological and reservoir data as well as production performance data. Revisions may result from changes in, among other things, reservoir performance, prices, economic conditions and governmental restrictions.

We recognize PUD reserves beyond one offset location where reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. In our Barnett Shale Asset, we had 60 proved undeveloped gas well locations at December 31, 2012, including 12 locations that are more than one offset. Additional information regarding our proved oil and gas reserves may be found under "Oil and Natural Gas Reserves" found in Item 1 of this Annual Report.

*Judgments and Assumptions*

All of the reserve data in this Annual Report are based on estimates. Estimates of our oil, natural gas and NGL reserves are prepared in accordance with guidelines established by the SEC. Reservoir engineering is a subjective process of estimating recoverable underground accumulations of oil, natural gas and NGLs. There are numerous uncertainties inherent in estimating recoverable quantities of proved oil and natural gas reserves. Uncertainties include the projection of future production rates and the expected timing of development expenditures. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of oil, natural gas and NGLs that are ultimately recovered.

The passage of time provides more qualitative information regarding estimates of reserves, and revisions are made to prior estimates to reflect updated information. The weighted average annual revisions to our reserve estimates over the last four years have been less than 7% of the weighted average previous year's estimate (excluding revisions due to price changes). However, there can be no assurance that more significant revisions will not be necessary in the future. If future significant revisions are necessary that reduce previously estimated reserve quantities, it could result in ceiling test-related impairments. In addition to the impact of the estimates of proved reserves on the calculation of the ceiling limitation, estimation of proved reserves is also a significant component of the calculation of depletion expense. For example, if estimates of proved reserves decline, the depletion rate will increase, resulting in a decrease in net income.

## Full Cost Ceiling Calculations

*Policy Description*

We use the full cost method to account for our oil and gas properties. Under the full cost method, all costs associated with the acquisition, exploration, and development of oil and gas properties are capitalized and accumulated in cost centers on a country-by-country basis. This includes any internal costs that are directly related to development and exploration activities, but does not include any costs related to production, general corporate overhead or similar activities. Proceeds received from disposals are credited against accumulated cost except when the sale represents a significant disposal of reserves, in which case a gain or loss is calculated and recognized. The application of the full cost method generally results in higher capitalized costs and higher depletion rates compared to its alternative, the successful efforts method. The sum of net capitalized costs and estimated future development and dismantlement costs for each cost center is depleted on the equivalent unit-of-production basis using proved oil and gas reserves. Excluded from amounts subject to depletion are costs associated with unevaluated properties.

Under the full cost method, net capitalized costs are limited to the lower of unamortized cost reduced by the related net deferred tax liability and asset retirement obligations or the cost center ceiling. The cost center ceiling is defined as the sum of (1) estimated future net revenue, discounted at 10% per annum, from proved reserves, based on the unweighted average of the preceding 12-month first day-of the-month prices adjusted to reflect local differentials and contract provisions, unescalated year-end costs and derivatives that are accounted for as hedges which are included in our oil and gas revenue, (2) the cost of properties not being amortized, (3) the lower of cost or market value of unproved properties included in the cost being amortized less (4) income tax effects related to differences between the book and tax bases of the oil and gas properties. If the net book value reduced by the related net deferred income tax liability and asset retirement obligations exceeds the cost center ceiling limitation, a non-cash impairment charge is required.

*Judgments and Assumptions*

The discounted present value of future net cash flows from our proved oil, natural gas and NGL reserves is the major component of the ceiling calculation, and is determined in connection with the estimation of our proved oil, natural gas and NGL reserves. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the timing of future expenditures. The process of reserve estimation requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. Different reserve engineers may make different estimates of reserve quantities based on the same data.

While the quantities of proved reserves require substantial judgment, the associated prices of natural gas, NGL and oil reserves, and the applicable discount rate that are used to calculate the discounted present value of the reserves do not require judgment. The current SEC rule requires the use of the future net cash flows from proved reserves discounted at 10%. Therefore, the future net cash flows associated with the proved reserves is not based on our assessment of future prices or costs. In calculating the ceiling, we adjust the future net cash flows by the discounted value of derivative contracts in place that hedge future prices. This valuation is determined by calculating the difference between reserve pricing and the contract prices for such hedges also discounted at 10%. At December 31, 2012, no derivatives were included in the ceiling.

Because the ceiling calculation dictates that our historical experience be held constant indefinitely and requires a 10% discount factor, the resulting value is not necessarily indicative of the fair value of the reserves or the oil and gas properties. Oil and natural gas prices have historically been volatile. At any time that we conduct a ceiling test, forecasted prices can be either substantially higher or lower than our historical experience. Also, marginal borrowing rates may be well below the required 10% used in the calculation. Rates below 10%, if they could be utilized, would have the effect of increasing the otherwise calculated ceiling amount. Therefore, oil and gas property ceiling test-related impairments that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves, should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

**Derivative Instruments**

*Policy Description*

We enter into derivatives to mitigate risk associated with the prices received from our natural gas, NGL and oil production. We may also utilize derivatives to hedge the risk associated with interest rates on our outstanding debt. All derivatives are recognized as either an asset or liability on the balance sheet measured at their fair value determined by reference to published future market prices and interest rates.

To designate a derivative as a cash flow hedge, we document at the hedge's inception our assessment that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which is updated at least quarterly, includes performing regression analysis and is generally based on the most recent relevant historical correlation between the derivative and the item hedged. If, during the derivative's term, we determine the hedge is no longer highly effective, hedge accounting is prospectively discontinued and any remaining unrealized gains or losses, based on the effective portion of the derivative at that date, are reclassified to earnings as revenue or interest expense when the underlying transaction occurs.

For derivatives that qualify as cash flow hedges, the effective portions of gains and losses are deferred in accumulated other comprehensive income and recognized in revenue or interest expense in the period in which the hedged transaction is recognized. Gains or losses on derivatives terminated prior to their original expiration date are deferred and recognized as earnings during the period covered by the hedge. If the hedged transaction is no longer probable, the deferred gain or loss would be immediately recorded to earnings. Changes in value of ineffective portions of hedges, if any, are recognized currently as a component of derivative gains (losses), net.

For derivatives that qualify as fair value hedges, such as interest rate swaps, the gains or losses are recognized currently in earnings, while the gains or losses on the hedged items adjust the carrying value of the hedged items and are recognized currently in earnings. Any gains or losses on the derivatives not offset by the gains or losses on the hedged items are recognized as the value of ineffectiveness in the hedge relationships. For derivatives that are not designated at their inception, we record an asset or liability for each instrument and recognize changes in fair value in earnings as a component of derivative (gains) losses, net.

Effective December 31, 2012, we discontinued the use of hedge accounting on all existing hedge contracts. Net deferred hedge gains deferred in AOCI associated with these contracts as of December 31, 2012 will be reclassified to earnings during the same periods in which the hedged transactions are recognized in our earnings. In the future we will recognize changes in the fair values of derivative contracts as gains or losses in the earnings of the periods in which they occur.

We enter into derivatives with counterparties who are our lenders at the inception of the derivative. All versions of our credit facility provide for collateralization of amounts outstanding from our derivatives in addition to amounts outstanding under the facility. Additionally, default on any of our obligations under derivatives with counterparty lenders could result in acceleration of the amounts outstanding under the credit facility. Our credit facility and our internal credit policies require that any counterparties, including facility lenders, with whom we enter into commodity derivatives have credit ratings that meet or exceed BBB- or Baa3 from Standard and Poor's or Moody's, respectively. The fair value for each derivative takes credit risk into consideration, whether it be our counterparties' or our own. Derivatives are classified as current or non-current derivative assets and liabilities, based on the expected timing of settlements.

*Judgments and Assumptions*

The estimates of the fair values of our commodity and interest rate derivative instruments require substantial judgment. Valuations are based upon multiple factors such as futures prices, volatility data from major oil and gas trading points, length of time to maturity, credit risks and interest rates. We compare our estimates of fair value for these instruments with valuations obtained from independent third parties and counterparty valuation confirmations. The values we report in our financial statements change as these estimates are revised to reflect actual results. Future changes to forecasted or realized commodity prices could result in significantly different values and realized cash flows for such instruments.

**Stock-Based Compensation**

*Policy Description*

An estimate of fair value is determined for all share-based payment awards. Recognition of compensation expense for all share-based payment awards is recognized over the vesting period for each award.

*Judgments and Assumptions*

Estimating the grant date fair value of our stock-based compensation requires management to make assumptions and to apply judgment to determine the grant date fair value of our awards. These assumptions and judgments include estimating the future volatility of our stock price, expected dividend yield, future employee turnover rates and future employee stock option exercise behaviors. Changes in these assumptions can materially affect the fair value estimate.

We do not believe there is a reasonable likelihood that there will be a material change in the future estimates or assumptions that we use to determine stock-based compensation expense. However, if actual results are not consistent with our estimates or assumptions, we may be exposed to changes in stock-based compensation expense that could be material. If actual results are not consistent with the assumptions used, the stock-based compensation expense reported in our financial statements may not be representative of the actual economic cost of the stock-based compensation.

**Income Taxes**

*Policy Description*

Deferred income taxes are established for all temporary differences between the book and the tax basis of assets and liabilities. In addition, deferred tax balances must be adjusted to reflect tax rates that we expect will be in effect during years in which we expect the temporary differences will reverse. Canadian taxes are computed at rates in effect or expected to be in effect in Canada. U.S. deferred tax liabilities are not recognized on profits that are expected to be permanently reinvested in Canada and thus are not considered available for distribution to us. Net operating loss carry-forwards and other deferred tax assets are reviewed annually for recoverability, and if necessary, are recorded net of a valuation allowance.

*Judgments and Assumptions*

We must assess the likelihood that deferred tax assets will be recovered from future taxable income. To the extent that we believe our deferred tax assets are not more likely than not to be realized, we must establish a valuation allowance. In making that assessment, we consider both positive and negative evidence related to the likelihood of realization of the deferred tax assets on a jurisdictional basis to determine, based on the weight of available evidence, whether it is more likely than not that some or all of the deferred tax assets will not be realized. Examples of positive and negative evidence include historical taxable income or losses, forecasted income or losses, the estimated timing of the reversals of existing temporary differences as well as prudent and feasible tax planning strategies. We consider a cumulative loss in recent years as a significant piece of negative evidence. A valuation allowance, by taxing jurisdiction, is established when necessary to reduce deferred tax assets to the amounts more likely than not expected to be realized. Significant management judgment is also required in determining the amount of financial statement benefit to record for uncertain tax positions. We consider the amounts and probabilities of the outcomes that could be realized upon ultimate settlement of an uncertain tax position using the facts, circumstances and information available at the reporting date to establish the appropriate amount of financial statement benefit. Our income tax provision would increase or decrease in the period in which the assessment is changed.

## OFF-BALANCE SHEET ARRANGEMENTS

Under our current contracts with NGTL, we expect to provide financial assurances to it during the construction phase of the Komie North Project, which is expected to begin no earlier than 2016 and be in place through 2018. Assuming the project is fully constructed at estimated costs of C$296.8 million, we expect to provide financial assurances in the form of letters of credit for some fractional portion of these costs. Note 14 to the consolidated financial statements found in Item 8 of this Annual Report contains additional information about our contracts with NGTL.

## RECENTLY ISSUED ACCOUNTING STANDARDS

The information regarding recent accounting pronouncements materially affecting our consolidated financial statements is included in Note 2 to our consolidated financial statements in Item 8 of this Annual Report, which is incorporated herein by reference.

## ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

### Commodity Price Risk

We enter into financial derivative contracts to mitigate our exposure to commodity price risk associated with anticipated future production and to increase the predictability of our revenue. As of December 31, 2012, the following forecasted production has been hedged with price swaps.

| Production Year | Daily Production Volume Gas |
|---|---|
| | MMcfd |
| **2013** | 200 |
| **2014** | 170 |
| **2015** | 150 |
| **2016-2021** | 40 |

We do not have NGL derivatives as of December 31, 2012.

Utilization of our financial hedging program will most often result in realized prices from the sale of our natural gas, NGL and oil that vary from market prices. As a result of settlements of derivative contracts, our revenue from natural gas, NGL and oil production was greater by $194.6 million, $84.8 million and $248.9 million for 2012, 2011 and 2010, respectively.

Effective December 31, 2012, we discontinued the use of hedge accounting. The net deferred hedge gain that is included in AOCI as of December 31, 2012 will be released into revenue from natural gas, NGL and oil production during the periods in which the hedged transaction is recognized in earnings. Subsequent to December 31, 2012, we will account for the derivative instruments utilizing the mark-to-market accounting method, whereby we recognize the changes in the fair values of our derivative contracts as gains or losses in the earnings of the period in which they occur.

The following table details our open derivative positions at December 31, 2012:

| | | | | | | Fair Value | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Country | Product | Type | Remaining Contract Period | Volume | Price Per Mcf | Total | 2013 | 2014 | 2015 | 2016 | 2017 | Thereafter |
| | | | | | | | | | (In thousands) | | | |
| Canada | Gas | Swap | Jan 2013-Dec 2013 | 10 MMcfd | $ 5.00 | 5,312 | 5,312 | — | — | — | — | — |
| Canada | Gas | Swap | Jan 2013-Dec 2015 | 10 MMcfd | 6.42 | 27,078 | 10,479 | 8,673 | 7,926 | — | — | — |
| Canada | Gas | Swap | Jan 2013-Dec 2015 | 10 MMcfd | 6.45 | 27,405 | 10,588 | 8,782 | 8,035 | — | — | — |
| Canada | Gas | Swap | Jan 2013-Dec 2015 | 10 MMcfd | 4.04 | 1,162 | 1,809 | 34 | (681) | — | — | — |
| Canada | Gas | Swap | Jan 2013-Dec 2021 | 10 MMcfd | 4.63 | (801) | 3,916 | 2,118 | 1,391 | 726 | (9) | (8,943) |
| US | Gas | Swap | Jan 2013-Dec 2013 | 10 MMcfd | 5.00 | 5,312 | 5,312 | — | — | — | — | — |
| US | Gas | Swap | Jan 2013-Dec 2013 | 20 MMcfd | 5.00 | 10,624 | 10,624 | — | — | — | — | — |
| US | Gas | Swap | Jan 2013-Dec 2014 | 10 MMcfd | 3.91 | 898 | 1,336 | (438) | — | — | — | — |
| US | Gas | Swap | Jan 2013-Dec 2014 | 10 MMcfd | 3.89 | 752 | 1,263 | (511) | — | — | — | — |
| US | Gas | Swap | Jan 2013-Dec 2015 | 20 MMcfd | 6.00 | 45,010 | 17,898 | 14,297 | 12,815 | — | — | — |
| US | Gas | Swap | Jan 2013-Dec 2015 | 10 MMcfd | 6.00 | 22,505 | 8,949 | 7,149 | 6,407 | — | — | — |
| US | Gas | Swap | Jan 2013-Dec 2015 | 5 MMcfd | 6.23 | 12,505 | 4,893 | 3,992 | 3,620 | — | — | — |
| US | Gas | Swap | Jan 2013-Dec 2015 | 5 MMcfd | 6.20 | 12,341 | 4,839 | 3,937 | 3,565 | — | — | — |
| US | Gas | Swap | Jan 2013-Dec 2015 | 5 MMcfd | 5.68 | 9,510 | 3,892 | 2,994 | 2,624 | — | — | — |
| US | Gas | Swap | Jan 2013-Dec 2015 | 5 MMcfd | 4.15 | 1,180 | 1,105 | 217 | (142) | — | — | — |
| US | Gas | Swap | Jan 2013-Dec 2015 | 5 MMcfd | 4.13 | 1,071 | 1,068 | 180 | (177) | — | — | — |
| US | Gas | Swap | Jan 2013-Dec 2015 | 7.5 MMcfd | 5.48 | 12,591 | 5,277 | 3,932 | 3,382 | — | — | — |
| US | Gas | Swap | Jan 2013-Dec 2015 | 7.5 MMcfd | 5.50 | 12,795 | 5,346 | 4,000 | 3,449 | — | — | — |
| US | Gas | Swap | Jan 2014-Dec 2015 | 5 MMcfd | 4.25 | 437 | — | 398 | 39 | — | — | — |
| US | Gas | Swap | Jan 2014-Dec 2015 | 5 MMcfd | 4.26 | 455 | — | 407 | 48 | — | — | — |
| US | Gas | Swap | Jan 2013-Dec 2021 | 10 MMcfd | 4.54 | (3,406) | 3,608 | 1,815 | 1,093 | 431 | (298) | (10,055) |
| US | Gas | Swap | Jan 2013-Dec 2021 | 5 MMcfd | 4.38 | (4,151) | 1,515 | 623 | 266 | (61) | (421) | (6,073) |
| US | Gas | Swap | Jan 2013-Dec 2021 | 5 MMcfd | 4.35 | (4,611) | 1,460 | 569 | 213 | (113) | (472) | (6,268) |
| US | Gas | Swap | Jan 2013-Dec 2021 | 10 MMcfd | 4.37 | (8,609) | 2,993 | 1,210 | 496 | (157) | (875) | (12,276) |
| | | | Grand Total | | | $ 187,365 | $ 113,482 | $ 64,378 | $ 54,369 | $ 826 | $ (2,075) | $ (43,615) |

The fair value of all derivative instruments included in these disclosures was estimated using prices quoted in markets for the periods covered by the derivatives and the value confirmed by counterparties and does not include an adjustment for counterparty credit risk. Estimates were determined by applying the net differential between the prices in each derivative and market prices for future periods to the amounts stipulated in each contract to arrive at an estimated future value. This estimated future value was discounted on each contract at rates commensurate with federal treasury instruments with similar contractual lives.

**Interest Rate Risk**

Changes in interest rates affect the interest rate we pay on borrowings under our Combined Credit Agreements. Our senior notes and senior subordinated notes have fixed interest rates and thus do not expose us to risk from fluctuations in market interest rates. Changes in interest rates do affect the fair value of our fixed rate debt.

In 2010, we executed early settlements of our interest rate swaps that were designated as fair value hedges of our senior notes due 2015 and our senior subordinated notes. We deferred gains of $30.8 million as a fair value adjustment to our debt, which we began to recognize over the life of the associated debt instruments. For 2012, 2011 and 2010, interest expense was reduced $5.1 million, $4.8 million and $14.0 million, respectively, because of our interest rate swaps.

Should we be required to borrow under our Combined Credit Agreements, and based on interest rates as of December 31, 2012, each $50 million in borrowings would result in additional annual interest payments of $1.7 million. If the current borrowing availability under our Combined Credit Agreements were to be fully utilized by year-end 2013 at interest rates as of December 31, 2012, we estimate that annual interest payments would increase by $13.5 million. If interest rates change by 1% on our December 31, 2012 variable debt balances of $388.2 million, our annual pre-tax income would decrease or increase by $3.9 million.

In the future, we may enter into interest rate derivative contracts on a portion of our outstanding debt to mitigate the risk of fluctuation of rates or manage the floating versus fixed rate risk.

**Foreign Currency Risk**

Our Canadian subsidiary uses the Canadian dollar as its functional currency. To the extent that business transactions in Canada are not denominated in Canadian dollars, we are exposed to foreign currency exchange rate risk. Non-functional currency transactions resulted in a gain of $0.1 million, included in net earnings for 2012 and losses of $2.5 million, and $0.5 million, respectively, included in net earnings for 2011 and 2010. Furthermore, the Amended and Restated Canadian Credit Facility permits Canadian borrowings to be made in either U.S. or Canadian-denominated amounts. However, the aggregate borrowing capacity of the entire facility is calculated using the U.S. dollar equivalent. Accordingly, there is a risk that exchange rate movements could impact our available borrowing capacity.

## ITEM 8. Financial Statements and Supplementary Data

### QUICKSILVER RESOURCES INC.
### INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Quicksilver Resources Inc.

We have audited the accompanying consolidated balance sheet of Quicksilver Resources Inc. as of December 31, 2012, and the related consolidated statements of income (loss) and comprehensive income (loss), equity, and cash flows for the year ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit 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 audit provides 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 Quicksilver Resources Inc. at December 31, 2012, and the consolidated results of its operations and its cash flows for the year ended December 31, 2012, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Quicksilver Resources Inc.'s 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 and our report dated March 22, 2013 expressed an adverse opinion on the effectiveness of internal control over financial reporting because of material weaknesses.

*/s/* Ernst & Young LLP

Fort Worth, Texas
March 22, 2013

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Quicksilver Resources Inc.
Fort Worth, Texas

We have audited the accompanying consolidated balance sheet of Quicksilver Resources Inc. and subsidiaries (the "Company") as of December 31, 2011, and the related consolidated statements of income (loss) and comprehensive income (loss), equity, and cash flows for the years ended December 31, 2011 and 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements 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, such consolidated financial statements present fairly, in all material respects, the financial position of Quicksilver Resources Inc. and subsidiaries at December 31, 2011, and the results of their operations and their cash flows for the years ended December 31, 2011 and 2010, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Fort Worth, Texas
April 15, 2012

## QUICKSILVER RESOURCES INC.
## CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)
## FOR THE YEARS ENDED DECEMBER 31, 2012, 2011 AND 2010
**In thousands, except for per share data**

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| Revenue | | | |
| Production | $ 630,947 | $ 800,543 | $ 856,349 |
| Sales of purchased natural gas | 62,405 | 86,645 | 64,089 |
| Derivative gains (losses), net (including realized gains of $42,798, $0 and $0, respectively) | 11,444 | 51,780 | (2,629) |
| Other | 4,242 | 4,655 | 10,522 |
| Total revenue | 709,038 | 943,623 | 928,331 |
| Operating expense | | | |
| Lease operating | 95,333 | 102,874 | 84,836 |
| Gathering, processing and transportation | 166,316 | 190,560 | 94,008 |
| Production and ad valorem taxes | 25,395 | 29,226 | 34,156 |
| Costs of purchased natural gas | 62,041 | 85,398 | 65,321 |
| Depletion, depreciation and accretion | 163,624 | 225,763 | 207,203 |
| Impairment | 2,625,928 | 107,059 | 47,997 |
| General and administrative | 75,697 | 79,582 | 80,107 |
| Other operating | 1,562 | 557 | 4,522 |
| Total expense | 3,215,896 | 821,019 | 618,150 |
| Gain on sale of KGS | — | — | 493,953 |
| Crestwood earn-out | 41,097 | — | — |
| Operating income (loss) | (2,465,761) | 122,604 | 804,134 |
| Income (loss) from earnings of BBEP | — | (8,439) | 22,323 |
| Other income (expense) - net | 1,108 | 219,768 | 75,724 |
| Fortune Creek accretion | (19,472) | — | — |
| Interest expense | (164,051) | (186,024) | (188,353) |
| Income (loss) before income taxes | (2,648,176) | 147,909 | 713,828 |
| Income tax (expense) benefit | 295,570 | (57,863) | (258,538) |
| Net income (loss) | (2,352,606) | 90,046 | 455,290 |
| Net income attributable to noncontrolling interests | — | — | (9,724) |
| Net income (loss) attributable to Quicksilver | $ (2,352,606) | $ 90,046 | $ 445,566 |
| Other comprehensive income (loss) | | | |
| Reclassification adjustments related to settlements of derivative contracts - net of income tax | (128,161) | (58,125) | (164,016) |
| Net change in derivative fair value - net of income tax | 74,384 | 156,160 | 156,850 |
| Foreign currency translation adjustment | 412 | (13,364) | 16,017 |
| Other comprehensive income (loss) | $ (53,365) | $ 84,671 | $ 8,851 |
| Comprehensive income (loss) | $ (2,405,971) | $ 174,717 | $ 454,417 |
| Earnings (loss) per common share - basic | $ (13.83) | $ 0.53 | $ 2.62 |
| Earnings (loss) per common share - diluted | $ (13.83) | $ 0.52 | $ 2.50 |

The accompanying notes are an integral part of these consolidated financial statements.

**QUICKSILVER RESOURCES INC.**
**CONSOLIDATED BALANCE SHEETS**
**AS OF DECEMBER 31, 2012 AND 2011**
**In thousands, except for share data**

| | 2012 | 2011 |
|---|---|---|
| **ASSETS** | | |
| Current assets | | |
| Cash and cash equivalents | $ 4,951 | $ 13,146 |
| Accounts receivable - net of allowance for doubtful accounts | 64,149 | 95,282 |
| Derivative assets at fair value | 113,367 | 162,845 |
| Other current assets | 25,046 | 29,154 |
| Total current assets | 207,513 | 300,427 |
| Property, plant and equipment - net | | |
| Oil and gas properties, full cost method (including unevaluated costs of $307,267 and $433,341, respectively) | 780,960 | 3,226,476 |
| Other property and equipment | 248,098 | 234,043 |
| Property, plant and equipment - net | 1,029,058 | 3,460,519 |
| Derivative assets at fair value | 105,270 | 183,982 |
| Other assets | 39,947 | 50,534 |
| | $ 1,381,788 | $ 3,995,462 |
| **LIABILITIES AND EQUITY** | | |
| Current liabilities | | |
| Current portion of long-term debt | $ — | $ 18 |
| Accounts payable | 37,131 | 142,672 |
| Accrued liabilities | 130,660 | 142,193 |
| Derivative liabilities at fair value | — | 4,028 |
| Current deferred tax liability | — | 45,262 |
| Total current liabilities | 167,791 | 334,173 |
| Long-term debt | 2,063,206 | 1,903,431 |
| Partnership liability | 130,912 | 122,913 |
| Asset retirement obligations | 115,949 | 85,568 |
| Derivative liabilities at fair value | 17,485 | — |
| Other liabilities | 19,242 | 28,461 |
| Deferred income taxes | — | 258,997 |
| Commitments and contingencies (Note 14) | | |
| Stockholders' equity | | |
| Preferred stock, par value $0.01, 10,000,000 shares authorized, none outstanding | — | — |
| Common stock, $0.01 par value, 400,000,000 shares authorized, and 179,015,118 and 176,980,483 shares issued, respectively | 1,790 | 1,770 |
| Additional paid in capital | 751,394 | 737,015 |
| Treasury stock of 5,921,102 and 5,379,702 shares, respectively | (49,495) | (46,351) |
| Accumulated other comprehensive income | 161,493 | 214,858 |
| Retained earnings (deficit) | (1,997,979) | 354,627 |
| Total stockholders' equity | (1,132,797) | 1,261,919 |
| | $ 1,381,788 | $ 3,995,462 |

The accompanying notes are an integral part of these consolidated financial statements.

# QUICKSILVER RESOURCES INC.
# CONSOLIDATED STATEMENTS OF EQUITY
# FOR THE YEARS ENDED DECEMBER 31, 2012, 2011 AND 2010
# In thousands

| | Quicksilver Resources Inc. Stockholders' Equity | | | | | | |
|---|---|---|---|---|---|---|---|
| | Common Stock | Additional Paid-in Capital | Treasury Stock | Accumulated Other Comprehensive Income | Retained Earnings (Deficit) | Noncontrolling Interest | Total |
| **Balances at December 31. 2009** | 1,745 | 730,265 | (36,363) | 121,336 | (180,985) | 60,824 | 696,822 |
| Net income | — | — | — | — | 445,566 | 9,724 | 455,290 |
| Hedge settlements reclassified into earnings from AOCI, net of income tax of $84,835 | — | — | — | (164,016) | — | — | (164,016) |
| Net change in derivative fair value, net of income tax of $78,616 | — | — | — | 156,850 | — | — | 156,850 |
| Foreign currency translation adjustment | — | — | — | 16,017 | — | — | 16,017 |
| Issuance & vesting of stock compensation | 7 | 23,531 | (5,124) | — | — | 4,339 | 22,753 |
| Stock option exercises | 3 | 2,012 | — | — | — | — | 2,015 |
| Issuance of KGS units | — | 6,746 | — | — | — | 4,308 | 11,054 |
| Distributions paid on KGS units | — | — | — | — | — | (13,550) | (13,550) |
| Disposition of KGS partnership interests | — | (47,685) | — | — | — | (65,645) | (113,330) |
| **Balances at December 31, 2010** | 1,755 | 714,869 | (41,487) | 130,187 | 264,581 | — | 1,069,905 |
| Net income | — | — | — | — | 90,046 | — | 90,046 |
| Hedge settlements reclassified into earnings from AOCI, net of income tax of $26,679 | — | — | — | (58,125) | — | — | (58,125) |
| Net change in derivative fair value, net of income tax of $73,339 | — | — | — | 156,160 | — | — | 156,160 |
| Foreign currency translation adjustment | — | — | — | (13,364) | — | — | (13,364) |
| Issuance & vesting of stock compensation | 13 | 20,849 | (4,864) | — | — | — | 15,998 |
| Stock option exercises | 2 | 1,297 | — | — | — | — | 1,299 |
| **Balances at December 31, 2011** | $ 1,770 | $ 737,015 | $ (46,351) | $ 214,858 | $ 354,627 | $ — | $ 1,261,919 |
| Net loss | — | — | — | — | (2,352,606) | — | (2,352,606) |
| Hedge settlements reclassified into earnings from AOCI, net of income tax of $66,417 | — | — | — | (128,161) | — | — | (128,161) |
| Net change in derivative fair value, net of income tax of $36,206 | — | — | — | 74,384 | — | — | 74,384 |
| Foreign currency translation adjustment | — | — | — | 412 | — | — | 412 |
| Issuance & vesting of stock compensation | 19 | 14,369 | (3,144) | — | — | — | 11,244 |
| Stock option exercises | 1 | 10 | — | — | — | — | 11 |
| **Balances at December 31, 2012** | $ 1,790 | $ 751,394 | $ (49,495) | $ 161,493 | $ (1,997,979) | $ — | $ (1,132,797) |

The accompanying notes are an integral part of these financial statements.

# QUICKSILVER RESOURCES INC.
# CONSOLIDATED STATEMENTS OF CASH FLOWS
# FOR THE YEARS END DECEMBER 31, 2012, 2011 AND 2010
## In thousands

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| Operating activities: | | | |
| Net income (loss) | $ (2,352,606) | $ 90,046 | $ 455,290 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | | |
| Depletion, depreciation and accretion | 163,624 | 225,763 | 207,203 |
| Impairment expense | 2,625,928 | 107,059 | 47,997 |
| Write-off of MLP filing fees | 7,505 | — | — |
| Crestwood earn-out | (41,097) | — | — |
| Deferred income tax expense (benefit) | (289,981) | 64,492 | 185,367 |
| Non-cash (gain) loss from hedging and derivative activities | 57,826 | (51,780) | (58,892) |
| Gain on sale of KGS | — | — | (493,953) |
| Divestiture expenses | — | — | 2,555 |
| Stock-based compensation | 22,246 | 20,862 | 25,990 |
| Non-cash interest expense | 9,854 | 16,510 | 17,226 |
| Fortune Creek accretion | 19,472 | — | — |
| Gain on disposition of BBEP units | — | (217,893) | (57,584) |
| Loss (income) from BBEP in excess of cash distributions | — | 28,269 | (1,417) |
| Other | 1,037 | 1,311 | (168) |
| Changes in assets and liabilities | | | |
| Accounts receivable | 30,950 | (31,803) | (9,501) |
| Derivative assets at fair value | — | — | 30,816 |
| Prepaid expenses and other assets | (4,435) | (6,017) | 6,364 |
| Accounts payable | (8,895) | (11,434) | 33,957 |
| Income taxes payable | 1,183 | (4,803) | 4,611 |
| Accrued and other liabilities | (14,884) | 22,471 | 1,859 |
| Net cash provided by operating activities | 227,727 | 253,053 | 397,720 |
| Investing activities: | | | |
| Capital expenditures | (485,479) | (690,607) | (695,114) |
| Proceeds from sale of KGS | — | — | 699,973 |
| Proceeds from Crestwood earn-out | 41,097 | — | — |
| Proceeds from sale of BBEP units | — | 272,965 | 34,016 |
| Proceeds from sale of properties and equipment | 72,725 | 4,163 | 9,953 |
| Net cash provided (used) by investing activities | (371,657) | (413,479) | 48,828 |
| Financing activities: | | | |
| Issuance of debt | 467,959 | 855,822 | 690,058 |
| Repayments of debt | (310,430) | (843,108) | (1,031,736) |
| Debt issuance costs paid | (3,022) | (12,506) | (3,111) |
| Partnership funds received | — | 122,913 | — |
| Gas Purchase Commitment repayments | — | — | (44,119) |
| Issuance of KGS common units - net offering costs | — | — | 11,054 |
| Distributions paid on KGS common units | — | — | (13,550) |
| Distribution of Fortune Creek Partnership funds | (14,285) | — | — |
| Proceeds from exercise of stock options | 11 | 1,299 | 1,801 |
| Excess tax benefits on stock compensation | — | — | 3,513 |
| Taxes paid on vesting of KGS equity compensation | — | — | (1,144) |
| Purchase of treasury stock | (3,144) | (4,864) | (4,910) |
| Net cash provided (used) by financing activities | 137,089 | 119,556 | (392,144) |
| Effect of exchange rate changes in cash | (1,354) | (921) | (1,252) |
| Net change in cash | (8,195) | (41,791) | 53,152 |
| Cash and cash equivalents at beginning of period | 13,146 | 54,937 | 1,785 |
| Cash and cash equivalents at end of period | $ 4,951 | $ 13,146 | $ 54,937 |

The accompanying notes are an integral part of these consolidated financial statements.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2012, 2011 AND 2010

### 1. NATURE OF OPERATIONS

We are an independent oil and gas company incorporated in the state of Delaware and headquartered in Fort Worth, Texas. We engage in the acquisition, exploration, development, production and sale of natural gas, NGLs and oil in North America. As of December 31, 2012, our significant oil and gas reserves and operations are located in:

- Texas
- U.S. Rocky Mountains
- Alberta
- British Columbia

We have offices located in:

- Fort Worth, Texas
- Glen Rose, Texas
- Cut Bank, Montana
- Craig, Colorado
- Calgary, Alberta
- Fort Nelson, British Columbia

Our results of operations are largely dependent on the difference between the prices received for our natural gas, NGL and oil products and the cost to find, develop, produce and market such resources. Natural gas, NGL and oil prices are subject to fluctuations in response to changes in supply, market uncertainty and a variety of other factors beyond our control. These factors include worldwide political instability, quantities of natural gas in storage, foreign supply of natural gas and oil, the price of foreign imports, the level of consumer demand and the price of available alternative fuels. We actively manage a portion of the financial risk relating to natural gas, NGL and oil price volatility through derivatives.

Due to the depressed price environment for natural gas, we have incurred significant impairments in 2012 on our oil and gas assets and in turn, tax valuation allowances which contributed to the consolidated net loss for 2012. At December 31, 2012, we have significant indebtedness, whose interest costs consume significant amounts of our operating cash flow. As more fully described in Note 11, at December 31, 2012 we did not meet an incurrence test in our indentures which is not an event of default, but as a result, we are limited in our ability to, among other things, incur additional debt. We do retain, however, the ability to utilize the full borrowing capacity under our Combined Credit Agreements and to refinance existing debt. Not meeting this ratio does not represent an event of default in our indentures. At December 31, 2012, there was \$401 million available from the \$850 million global borrowing base under the Combined Credit Agreements, including \$179.2 million of available letter of credit capacity. The next semi-annual redetermination of the Combined Credit Agreement is scheduled for April 2013 and we expect the borrowing base will be reduced. We have significantly reduced our 2013 capital program compared to prior years and anticipate the program will be substantially funded by cash flow from operations. We project that we will maintain compliance with the financial covenants associated with our Combined Credit Agreements in 2013, however we do not expect to exceed the required levels by a significant margin, and we may have to cut costs in response to commodity price changes or other factors should they arise. Note 11 contains additional discussion of our covenant requirements. In addition, in 2014, absent an improvement in natural gas and NGL prices, significant deleveraging from a strategic transaction, reduced interest costs on our debt through refinancing or significant reductions to our operating costs, we may not comply with our interest coverage requirement under our Combined Credit Agreements and expect that we would need to seek additional covenant relief under the Combined Credit Agreements in 2014. We are currently pursuing joint venture partners in our Barnett Shale Asset and Horn River Asset. Any joint venture is likely to result in cash proceeds to us and a reduction in our capital expenditures and liquidity requirements, however we may be unsuccessful in completing a joint venture.

## 2. SIGNIFICANT ACCOUNTING POLICIES

### Unaudited Quarterly Financial Statement Restatement

As part of our year-end 2012 procedures, certain derivatives that were originally accounted for as hedges were determined to not qualify for hedge accounting. Additionally, these derivatives were no longer allowed to be included in the full cost ceiling calculations resulting in adjustments to impairment, deferred taxes and to a lessor degree depletion during the quarters. We also restated our ceiling test for Canada for the first two quarters of 2012 to correct for inappropriate inclusion of non-property related deferred taxes in the ceiling limitation. Income taxes have also been restated for each of the 2012 quarters to reflect the foregoing restated items. Additional details are provided in the Supplemental Selected Quarterly Financial Data.

### Basis of Presentation

Our consolidated financial statements include our accounts and those of all of our majority-owned subsidiaries, companies over which we exercise control through majority voting rights or other means of control and variable interest entities of which we are the primary beneficiary. We eliminate all inter-company balances and transactions in preparing consolidated financial statements. We account for our ownership in unincorporated partnerships and companies, including our prior interest in BBEP, under the equity method when we have significant influence over those entities, but because of terms of the ownership agreements, we do not meet the criteria for consolidation of the entities.

### Use of Estimates

The preparation of financial statements in conformity with GAAP requires our management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expense during each reporting period. Management believes its estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties, which may cause actual results to differ materially from management's estimates.

Significant estimates underlying these financial statements include the estimated quantities of proved natural gas, NGL and oil reserves (including the associated future net cash flows from those proved reserves) used to compute depletion expense, the full cost ceiling limitation and estimates of current revenue. Other estimates that require assumptions concerning future events and substantial judgment include the estimated fair values of derivatives, asset retirement obligations and employee stock-based compensation. Income taxes also involve the use of considerable judgment in the estimation and evaluation of deferred income tax assets and our ability to recover operating loss carry-forwards and assessment of uncertain tax positions.

### Cash Equivalents

Cash equivalents consist of time deposits and liquid debt investments with original maturities of three months or less at the time of purchase.

### Accounts Receivable

We sell our natural gas, NGL and oil production to various purchasers. Each of our counterparties is reviewed as to credit worthiness prior to the extension of credit and on a regular basis thereafter. Although we do not require collateral, we require appropriate credit ratings and, in some instances, obtain parental guarantees. Receivables are generally collected within 30 to 60 days. When collections of specific amounts due are no longer reasonably assured, we establish an allowance for doubtful accounts though we have not had a significant instance of nonpayment. During 2012, two purchasers individually accounted for 21% and 15% of cash collected for our consolidated natural gas, NGL and oil sales. During 2011, two purchasers individually accounted for 15% and 11% of cash collected for our consolidated natural gas, NGL and oil sales. During 2010, two purchasers accounted for 17% and 12% of cash collected for our consolidated natural gas, NGL and oil sales.

### Hedging and Derivatives

We enter into derivatives to mitigate risk associated with the prices received from our natural gas, NGL and oil production. We may also utilize derivatives to hedge the risk associated with interest rates on our outstanding debt. All derivatives are recognized as either an asset or liability on the balance sheet measured at their fair value determined by reference to published future market prices and interest rates.

To designate a derivative as a cash flow hedge, we document at the hedge's inception our assessment that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which is updated at least quarterly, includes performing regression analysis and is generally based on the most recent relevant historical correlation between the derivative and the item hedged. If, during the derivative's term, we determine the hedge is no longer highly effective, hedge accounting is prospectively discontinued and any remaining unrealized gains or losses, based on the effective portion of the derivative at that date, are reclassified to earnings as revenue or interest expense when the underlying transaction occurs.

For derivatives that qualify as cash flow hedges, the effective portions of gains and losses are deferred in accumulated other comprehensive income and recognized in revenue or interest expense in the period in which the hedged transaction is recognized. Gains or losses on derivatives terminated prior to their original expiration date are deferred and recognized as earnings during the period that the hedge covered. If the hedged transaction is no longer probable, the deferred gain or loss would be immediately recorded to earnings. Changes in value of ineffective portions of hedges, if any, are recognized currently as a component of derivative gains (losses), net.

For derivatives that qualify as fair value hedges, such as interest rate swaps, the gains or losses are recognized currently in earnings, while the gains or losses on the hedged items adjust the carrying value of the hedged items and are recognized currently in earnings. Any gains or losses on the derivatives not offset by the gains or losses on the hedged items are recognized as the value of ineffectiveness in the hedge relationships. For derivatives that are not hedges, we record an asset or liability for each instrument and recognize changes as a component of derivative gains (losses), net.

Effective December 31, 2012, we discontinued the use of hedge accounting on all existing hedge contracts. Net deferred hedge gains deferred in AOCI associated with these contracts as of December 31, 2012 will be reclassified to earnings during the same periods in which the hedged transactions are recognized in our earnings. In the future we will recognize changes in the fair values of derivative contracts as gains or losses in the earnings of the periods in which they occur.

We enter into derivatives with counterparties who are our lenders at the inception of the derivative. Our credit facility provides for collateralization of amounts outstanding from our derivatives in addition to amounts outstanding under the facility. Additionally, default on any of our obligations under derivatives with counterparty lenders could result in acceleration of the amounts outstanding under the credit facility. Our credit facility and our internal credit policies require that any counterparties, including facility lenders, with whom we enter into commodity derivatives have credit ratings that meet or exceed BBB- or Baa3 from Standard and Poor's or Moody's, respectively. The fair value for each derivative takes credit risk into consideration, whether it be our counterparties' or our own. Derivatives are classified as current or non-current derivative assets and liabilities, based on the expected timing of settlements.

**Investments in Equity Affiliates**

During December 2011, we liquidated our investment in BBEP which we had accounted for using the equity method. Prior to this liquidation, we reviewed our investment for impairment whenever events or circumstances indicated that the investment's carrying amount may not be recoverable. We recorded our portion of BBEP's earnings during the quarter in which its financial statements became publicly available. Consequently, our 2011 and 2010 annual results of operations include BBEP's earnings for the 12 months ended September 30, 2011, and 2010. Note 7 contains more information on our BBEP investment.

**Property, Plant, and Equipment**

We follow the full cost method in accounting for our oil and gas properties. Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties are capitalized and accumulated in cost centers on a country-by-country basis. This includes any internal costs that are directly related to development and exploration activities, but does not include any costs related to production, general corporate overhead or similar activities. Proceeds received from disposals reduce the accumulated cost except when the sale represents a significant disposal of reserves, in which case a gain or loss is calculated and recognized. The sum of net capitalized costs and estimated future development and dismantlement costs for each cost center is depleted on the equivalent unit-of-production method, based on proved oil and gas reserves. We may exclude costs associated with unevaluated properties from amounts subject to depletion.

Under the full cost method, net capitalized costs are limited to the lower of unamortized cost reduced by the related net deferred tax liability and asset retirement obligations or the cost center ceiling. The cost center ceiling is defined as the sum of (1) estimated future net revenue from proved reserves, discounted at 10% per annum, including the effects of derivatives that are accounted for as hedges of our oil and gas revenue, (2) the cost of properties not being amortized, (3) the lower of cost or market value of unproved properties included in the cost being amortized, less (4) income tax effects related to differences between the book and tax basis of the natural gas and oil properties. If the net book value reduced by the related net deferred income tax liability and asset retirement obligations exceeds the cost center ceiling limitation, a non-cash impairment charge is required. Note 8 to these financial statements contains further discussion of the ceiling test.

Other properties and equipment are stated at original cost and depreciated using the straight-line method based on estimated useful lives ranging from five to forty years.

### Inventory

Inventories were primarily comprised of materials and parts including oil and gas drilling or repair items such as tubing, casing, chemicals, operating supplies and ordinary maintenance materials and parts. The materials, parts and supplies inventory is primarily acquired for use in future drilling operations or repair operations and is carried at the lower of cost or fair value, on a first-in, first-out cost basis. Fair value represents net realizable value, which is the amount that we are allowed to bill to the joint accounts under joint operating agreements to which we are a party. Impairments for materials and supplies inventories are recorded as lease operating expense in the accompanying consolidated statements of operations.

### Asset Retirement Obligations

We record the fair value of the liability for asset retirement obligations in the period in which it is legally or contractually incurred. Upon initial recognition of the asset retirement liability, an asset retirement cost is capitalized by increasing the carrying amount of the asset by the same amount as the liability. In periods subsequent to initial measurement, the asset retirement cost is recognized as expense through depletion or depreciation over the asset's useful life. Changes in the liability for the asset retirement obligations are recognized for (1) the passage of time and (2) revisions to either the timing or the amount of estimated cash flows. Accretion expense is recognized for the impacts of increasing the discounted fair value to its estimated settlement value.

### Revenue Recognition

Revenue is recognized when title to the products transfers to the purchaser. We use the "sales method" to account for our production revenue, whereby we recognize revenue on all production sold to our purchasers, regardless of whether the sales are proportionate to our ownership in the property. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than the expected remaining proved reserves. As of December 31, 2012 and 2011, our aggregate production imbalances were not material.

### Environmental Compliance and Remediation

Environmental compliance costs, including ongoing maintenance and monitoring, are expensed as incurred. Those environmental remediation costs which improve a property are capitalized.

### Debt

We record all debt instruments at face value. When an issuance of debt is made at other than par, a discount or premium is separately recorded. The discount or premium is amortized over the life of the debt using the effective interest method. We separately accounted for the liability and equity components of our convertible debentures, which resulted in our recognizing interest expense at our effective borrowing rate in effect at the time of issuance. Note 11 contains further information regarding convertible debentures.

### Income Taxes

Deferred income taxes are established for all temporary differences between the book and the tax basis of assets and liabilities. In addition, deferred tax balances must reflect tax rates expected to be in effect in years in which the temporary differences reverse. Canadian taxes are calculated at rates expected to be in effect in Canada. U.S. deferred tax liabilities are not recognized on profits that are expected to be permanently reinvested in Canada and thus not considered available for distribution to the parent company. Net operating loss carry-forwards and other deferred tax assets are reviewed annually for recoverability, and, if necessary, are recorded net of a valuation allowance. Note 13 contains additional discussion regarding income taxes.

### Stock-based Compensation

We measure and recognize compensation expense for all share-based payment awards made to employees and directors based on their estimated fair value at the time the awards are granted. Our board of directors may elect to issue awards payable in cash. For all awards, we recognize the expense associated with the awards over the vesting period. The liability for fair value of cash awards is reassessed at every balance sheet date, such that the vested portion of the liability is adjusted to reflect revised fair value through compensation expense.

### Disclosure of Fair Value of Financial Instruments

Our financial instruments include cash, time deposits, accounts receivable, notes payable, accounts payable, long-term debt and financial derivatives. The fair value of long-term debt is estimated as the present value of future cash flows discounted at rates consistent with comparable maturities and includes consideration of credit risk. The carrying amounts reflected in the balance sheet for financial assets classified as current assets and the carrying amounts for financial liabilities classified as current liabilities approximate fair value.

### Foreign Currency Translation

Our Canadian subsidiary maintains its general ledger using the Canadian dollar. All balance sheet accounts of our Canadian operations are translated into U.S. dollars at the period end exchange rate and statement of income items are translated at the weighted average exchange rate for the period. The resulting translation adjustments are made directly to a component of accumulated other comprehensive income within stockholders' equity. Gains and losses from foreign currency transactions are included in the consolidated results of operations.

### Noncontrolling Interests in Consolidated Subsidiaries

Noncontrolling interests reflect the fractional outside ownership of our majority-owned and consolidated subsidiaries. Until we sold all of our interests in KGS in October 2010, we included the results of operations and financial position of KGS in our consolidated financial statements and recognized the portion of KGS' results of operations attributable to unaffiliated unitholders as a component of "income attributable to noncontrolling interests."

### Variable Interest Entities

An entity is a variable interest entity (VIE) if it meets the following criteria: (1) the entity has equity that is insufficient to permit the entity to finance its activities without additional subordinated financial support from other parties, or (2) the entity has equity investors that cannot make significant decisions about the entity's operations or that do not absorb their proportionate share of the expected losses or receive the expected returns of the entity.

VIEs require assessment of who the primary beneficiary is and whether the primary beneficiary should consolidate the VIE. The primary beneficiary is identified as the variable interest holder that has both the power to direct the activities of the variable interest entity that most significantly impacts the entity's economic performance and the obligation to absorb losses or the right to receive benefits from the entity that could potentially be significant to the variable interest entity. Application of the VIE consolidation requirements may require the exercise of significant judgment by management.

In December 2011, we began to include the financial position of Fortune Creek and the results of operations we included beginning with the period ended December 31, 2011 in our consolidated financial statements. The results from operations for Fortune Creek for 2011 were immaterial. Note 16 contains additional discussion regarding Fortune Creek.

### Earnings per Share

We report basic earnings per common share, which excludes the effect of potentially dilutive securities, and diluted earnings per common share, which includes the effect of all potentially dilutive securities unless their impact is antidilutive. Note 18 includes the calculation of earnings per share.

### Recently Issued Accounting Standards

In December 2011, the FASB issued an amendment to the accounting guidance for disclosure of arrangements that permit offsetting assets and liabilities. The amendment expands the disclosure requirements to require both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. The amendment will be effective for us beginning on January 1, 2013, and must be applied retrospectively. We do not expect the adoption of this accounting pronouncement to have a material impact on our financial statements when implemented.

No other pronouncements materially affecting our financial statements have been issued since the filing of our 2011 Annual Report on Form 10-K.

## 3. ACQUISITIONS AND DIVESTITURES

*2012 SWEPI Transaction*

On December 28, 2012, we entered into an agreement with SWEPI LP to jointly develop our oil and gas interests in the Niobrara formation of the Sand Wash Basin and to establish an Area of Mutual Interest ("AMI") covering in excess of 850,000 acres. Each party assigned to the other a 50% working interest in the majority of its combined acreage so that each party owns a 50% interest in more than 320,000 acres and has the right to a 50% interest in any acquisition within the AMI. SWEPI paid us an equalization payment for 50% of the acreage contributed by us in excess of the acreage that SWEPI contributed. SWEPI is the operator of the majority of the jointly owned lands. This relationship is strategic to the development of the Niobrara Asset as it created contiguous acreage blocks, which will lead to a more orderly and cost-effective development of the basin.

*2010 Crestwood Transaction and Midstream Operations*

In October 2010, we completed the sale of all of our interests in KGS to Crestwood. The Crestwood Transaction included our conveying:

- a 100% ownership interest in Quicksilver Gas Services Holdings LLC, which owned:
  - 5,696,752 common units of KGS;
  - 11,513,625 subordinated units of KGS representing limited partner interests in KGS; and
  - 100% of the outstanding membership interests in Quicksilver Gas Services GP LLC including 469,944 general partner units in KGS and 100% of the outstanding incentive distribution rights in KGS; and
- a subordinated promissory note issued to us by KGS with a carrying value of $58 million at September 30, 2010.

We received net proceeds of $700 million, including $8.0 million from KGS distributions in the third quarter of 2010, and recognized a gain of $494 million. In February 2012, we collected $41 million in earn-out payments and we have the right to collect an additional $31 million in future earn-out payments in 2013, but will not receive any additional payment.

Under the agreements governing the Crestwood Transaction, we agreed not to compete with CMLP (to which KGS was renamed) with respect to the gathering, treating and processing of natural gas and the transportation of natural gas liquids in Denton, Hood, Somervell, Johnson, Tarrant, Parker, Bosque and Erath Counties in Texas. We also entered into an agreement with CMLP for the joint development of areas governed by certain of our existing agreements, and further, we amended our existing agreements. The most significant amendments include extending the terms of all gathering agreements with CMLP through 2020 and establishing a fixed gathering rate of $0.55 per Mcf for the gathering system in our Alliance Asset.

In September 2010, our board of directors approved a plan for disposal of the HCDS, which is included in our midstream segment. We conducted an impairment analysis of the HCDS and recognized a charge of $28.6 million for impairment in the third quarter of 2010. During the fourth quarter of 2011, we discontinued our efforts to actively market the HCDS assets to prospective buyers. GAAP also generally limits reporting such items as held for sale to one year. As a result, we did not report the HCDS in our financial statements as an asset held for sale as of December 31, 2011. Further, we recognized an additional impairment charge of $10.3 million in 2011 for HCDS.

We have continued to report our interests sold in the Crestwood Transaction and the HCDS as part of our continuing operating results because our use of their midstream services constitutes a "continuation of service" that precludes presentation of those businesses as discontinued operations under GAAP.

The operating results of these midstream operations, as classified in our statement of income, are summarized below:

| | For the Year Ended December 31, 2010 |
|---|---|
| | (In thousands) |
| Revenue | $ 13,119 |
| Lease operating expense | — |
| GPT expense [(1)] | (57,679) |
| Ad valorem taxes | 3,764 |
| Other operations | 3,444 |
| DD&A | 19,732 |
| General and administrative expense | 5,034 |
| Impairment expense | 28,611 |
| Operating results of midstream operations | 10,213 |
| Interest and other expense | (6,916) |
| Results of midstream operations before income tax | 3,297 |
| Income tax expense | (1,265) |
| Results of midstream operations, net of income tax | $ 2,032 |

(1) Our KGS operations earned revenue from processing and gathering of our natural gas and NGL production. This revenue was consolidated as a reduction of processing, gathering and transportation expense for purposes of presenting our consolidated statements of income.

*2010 Lake Arlington Acquisition*

In May 2010, we completed the acquisition of an additional 25% working interest in our company-operated Lake Arlington Asset, for which we conveyed $62.1 million in cash and 3,619,901 BBEP Units owned by us with a market value of $54.4 million on the date of closing. We recognized a gain of $35.4 million as other income for the difference between our carrying value of $5.24 per BBEP Unit and the fair value of $15.03 per BBEP Unit on the date of the transaction.

## 4. DERIVATIVES AND FAIR VALUE MEASUREMENTS

The following table categorizes our commodity derivative instruments based upon the use of input levels:

| | Asset Derivatives As of December 31, 2012 | Asset Derivatives As of December 31, 2011 | Liability Derivatives As of December 31, 2012 | Liability Derivatives As of December 31, 2011 |
|---|---|---|---|---|
| | (in thousands) | | (in thousands) | |
| Level 2 inputs | $ 207,042 | $ 195,838 | $ 959 | $ 4,028 |
| Level 3 inputs | 11,595 | 150,989 | 16,526 | — |
| Total | $ 218,637 | $ 346,827 | $ 17,485 | $ 4,028 |

The fair value of "Level 2" derivative instruments included in these disclosures was estimated using prices quoted in active markets for the periods covered by the derivatives and the value reported by counterparties. The fair value of derivative instruments designated "Level 3" was estimated using prices quoted in markets where there is insufficient market activity for consideration as "Level 2" instruments. Currently, only our natural gas derivatives with an original tenure of 10 years utilize "Level 3" inputs, primarily due to comparatively less market data available for the later portion of their term compared with our shorter term derivatives. The fair value of both the "Level 2" and the "Level 3" assets and liabilities are determined using a discounted cash flow model using the terms of the derivative instrument, market prices for the periods covered by the derivatives, and the credit adjusted risk-free interest rates. The "Level 3" unobservable inputs are the market prices for the latter half of the 10-year term as there is not an active market for that period of time. These unobservable inputs included within the fair value calculation range from $3.35 to $6.10 and are based upon prices quoted in active markets for the period of time available and applying the differential from this period of time to the market prices for the later years in the term. Changes in the "Level 3" inputs are correlated to the changes in the quoted market prices for the period of time available. Estimates were determined by applying the differential between the prices in each derivative and market prices for future periods to the amounts stipulated in each contract to arrive at an estimated future value. This estimated future value was discounted on each contract at the credit adjusted risk-free rate.

The following table identifies the changes in "Level 3" fair values for the periods indicated:

| | As of December 31, 2012 | As of December 31, 2011 |
|---|---|---|
| | (In thousands) | |
| Balance at beginning of period | $ 150,989 | $ — |
| Total gains (losses) for the period: | | |
| Unrealized gain (loss) | 19,451 | 45,852 |
| Transfers out of Level 3 | (180,732) | — |
| Settlements in production revenue | (3,738) | — |
| Settlements in derivative gains (losses), net | (25,203) | — |
| Unrealized gains reported in OCI | 34,302 | 105,137 |
| Balance at end of period | $ (4,931) | $ 150,989 |
| The amount of total gains or losses for the period included in derivative gains (losses), net attributable to the change in unrealized gains or losses related to assets still held at the reporting date | $ 19,451 | $ 45,852 |

Transfers from Level 3 to Level 2 represent our ten-year derivative instruments that were exchanged in 2012 for derivative instruments with shorter durations and are valued on the date of the transfer.

*Commodity Price Derivatives*

As of December 31, 2012, we had swaps as follows:

| **Production Year** | **Daily Production Volume** **Gas** |
|---|---|
| | MMcfd |
| **2013** | 200 |
| **2014** | 170 |
| **2015** | 150 |
| **2016-2021** | 40 |

We have no NGL derivatives as of December 31, 2012. Effective December 31, 2012, we discontinued the use of hedge accounting. The net deferred hedge gain that is included in AOCI as of December 31, 2012 will be released into revenue from natural gas, NGL and oil production during the following periods in which we expect the underlying production to occur:

| (In thousands) | |
|---|---|
| 2013 | $ 69,594 |
| 2014 | 37,084 |
| 2015 | 33,191 |
| 2016 | 13,476 |
| 2017 and thereafter | $ 53,973 |
| | $ 207,318 |

Subsequent to December 31, 2012, we will account for the derivative instruments utilizing the mark-to-market accounting method, whereby we recognize the changes in the fair values of our derivative contracts as gains or losses in the earnings of the period in which they occur.

*Interest Rate Derivatives*

In February 2010, we executed the early settlement of our 2009 interest rate swaps that were designated as fair value hedges of our senior notes due 2015 and our senior subordinated notes. We received cash of $18.0 million in the settlement, including $3.7 million for interest previously accrued and earned, and recognized the remaining $14.3 million as a fair value adjustment to our debt.

In February 2010, we entered into new interest swaps to hedge the same debt instruments. We executed early settlement of a portion of the 2010 interest rate swaps in May 2010 and the remaining 2010 interest swaps in July 2010 for $6.8 million and $16.7 million, respectively. These settlements included $7.0 million for interest previously accrued and earned. The remaining cash of $16.5 million was recognized as a fair value adjustment to our debt.

The remaining deferral of these early settlements from all interest rate swaps will continue to be recognized as a reduction of interest expense over the life of the associated underlying debt instruments currently estimated as follows:

| (In thousands) | |
|---|---|
| 2013 | $ 5,539 |
| 2014 | 6,012 |
| 2015 | 4,669 |
| 2016 | 568 |
| | $ 16,788 |

*All Derivatives*

The estimated fair value of all of our derivatives at December 31, 2012 and 2011 were as follows:

| | Asset Derivatives As of December 31, 2012 | Asset Derivatives As of December 31, 2011 | Liability Derivatives As of December 31, 2012 | Liability Derivatives As of December 31, 2011 |
|---|---|---|---|---|
| | (In thousands) | | (In thousands) | |
| Derivatives designated as hedges: | | | | |
| Commodity contracts reported in: | | | | |
| Current derivative assets | $ — | $ 165,484 | $ — | $ 2,639 |
| Noncurrent derivative assets | — | 183,982 | — | — |
| Current derivative liabilities | — | — | — | 4,028 |
| Noncurrent derivative liabilities | — | — | — | — |
| Total derivatives designated as hedges | $ — | $ 349,466 | $ — | $ 6,667 |
| Derivatives not designated as hedges: | | | | |
| Commodity contracts reported in: | | | | |
| Current derivative assets | $ 113,367 | $ — | $ — | $ — |
| Noncurrent derivative assets | 107,542 | — | 2,272 | — |
| Current derivative liabilities | — | — | — | — |
| Noncurrent derivative liabilities | 92 | — | 17,577 | — |
| Total derivatives not designated as hedges | $ 221,001 | $ — | $ 19,849 | $ — |
| Total derivatives | $ 221,001 | $ 349,466 | $ 19,849 | $ 6,667 |

The changes in the carrying value of our hedges for 2012 and 2011 are presented below:

| | For the Years Ended December 31, 2012 Commodity Hedges | For the Years Ended December 31, 2011 Commodity Hedges |
|---|---|---|
| | (In thousands) | |
| Derivative fair value at beginning of period | $ 342,799 | $ 146,762 |
| Change in net amounts receivable and payable | — | (759) |
| Settlements in production revenue | (176,084) | (84,046) |
| Settlements in derivatives (gains) losses, net | (3,820) | — |
| Settlements deferred in OCI | — | — |
| Ineffectiveness reported in derivative gains (losses), net | 1,281 | 5,928 |
| Unrealized gains (losses) reported in derivative gains (losses), net | — | 45,852 |
| Unrealized gains reported in OCI | 107,112 | 229,062 |
| Derecognition of hedge | (271,288) | — |
| Derivative fair value at end of period | $ — | $ 342,799 |

Gains and losses from the effective portion of derivative assets and liabilities held in AOCI expected to be reclassified into earnings during 2013 would result in a gain of $46.7 million net of income taxes. Hedge derivative ineffectiveness resulted in net gains of $1.3 million and $5.9 million for 2012 and 2011, respectively, and net loss of $2.6 million for 2010.

*Financial instruments not carried at fair value*

Carrying values and fair values of financial instruments that are not carried at fair value in the consolidated balance sheet as of December 31, 2012 and 2011 are included in Note 11.

## 5. ACCOUNTS RECEIVABLE

Accounts receivable consisted of the following:

| | As of December 31, 2012 | As of December 31, 2011 |
|---|---|---|
| | (In thousands) | |
| Accrued production revenue | $ 49,762 | $ 57,220 |
| Joint interest billings | 10,957 | 7,770 |
| Income taxes | — | 13,332 |
| Canadian value added taxes | 172 | 14,750 |
| NGL hedge settlement accrual | 3,149 | — |
| Other | 160 | 2,247 |
| Allowance for doubtful accounts | (51) | (37) |
| | $ 64,149 | $ 95,282 |

## 6. OTHER CURRENT ASSETS

Other current assets consisted of the following:

| | As of December 31, 2012 | As of December 31, 2011 |
|---|---|---|
| | (In thousands) | |
| Inventories | $ 21,454 | $ 25,503 |
| Deposits | 513 | 391 |
| Other prepaid expense | 3,079 | 3,260 |
| | $ 25,046 | $ 29,154 |

## 7. INVESTMENT IN BBEP

We initially received 21.4 million BBEP Units during November 2007 as partial consideration for the sale of our oil and gas properties in Michigan, Indiana and Kentucky.

Since December 31, 2011 we own no BBEP Units. Note 3 contains additional information regarding the use of 3.6 million BBEP Units as partial consideration in the acquisition of oil and gas properties in May 2010. We further reduced our ownership in September 2010 when we sold 1.4 million BBEP Units at a unit price of $16.22, net of fees paid. We recognized a gain of $14.4 million as other income for the difference between our carrying value at the time of the sale of $5.82 per BBEP Unit and the net sales proceeds. In October 2010, we sold an additional 650,000 BBEP Units at a unit price of $17.72 and recognized a gain of $7.7 million.

Our ownership interest in BBEP was further reduced in February 2011 when BBEP issued approximately 4.9 million BBEP Units. During 2011, we eliminated our ownership through the sale of approximately 15.7 million BBEP Units at a weighted average unit sales price of $17.40. We recognized gains of $217.9 million as other income for the difference between our weighted average carrying value of $3.51 per BBEP Unit and the net sales proceeds.

We accounted for our investment in BBEP Units using the equity method, utilizing a one-quarter lag from BBEP's publicly available information. Summarized financial information for BBEP is as follows:

| | For the Twelve Months Ended September 30, | |
|---|---|---|
| | 2011 | 2010 |
| | (in thousands) | |
| Revenue [1] | $ 425,386 | $ 375,446 |
| Operating expense | 313,388 | 285,394 |
| Operating income | 111,998 | 90,052 |
| Interest and other [2] | 40,759 | 24,903 |
| Income tax (benefit) expense | 1,070 | (939) |
| Noncontrolling interests | 183 | 146 |
| Net income available to BBEP | $ 69,986 | $ 65,942 |
| Net income available to common unitholders | $ 69,986 | $ 65,942 |

(1) For the twelve months ended September 30, 2011, unrealized gains of $24.0 million on commodity derivatives were recognized. For the twelve months ended September 30, 2010, unrealized losses of $12.1 million on commodity derivatives were recognized.

(2) The twelve months ended September 30, 2011 and 2010 included $3.3 million and $5.2 million, respectively, for unrealized gains on interest rate swaps.

| | As of September 30, |
|---|---|
| | 2011 |
| | (In thousands) |
| Current assets | $ 171,850 |
| Property, plant and equipment | 1,765,247 |
| Other assets | 104,264 |
| Current liabilities | 85,608 |
| Long-term debt | 511,489 |
| Other non-current liabilities | 55,042 |
| Partners' equity | 1,389,222 |

Changes in the balance of our investment in BBEP for 2011 were as follows:

| | As of December 31, |
|---|---|
| | 2011 |
| | (In thousands) |
| Beginning investment balance | $ 83,341 |
| Income (loss) from earnings in BBEP | (8,439) |
| Distributions from BBEP | (19,830) |
| Disposal of BBEP Units | (55,072) |
| Ending investment balance | $ — |

## 8. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consisted of the following:

| | As of December 31, 2012 | As of December 31, 2011 |
|---|---|---|
| | (In thousands) | |
| Oil and gas properties | | |
| Subject to depletion | $ 5,770,913 | $ 5,309,330 |
| Unevaluated costs | 307,267 | 433,341 |
| Accumulated depletion | (5,297,220) | (2,516,195) |
| Net oil and gas properties | 780,960 | 3,226,476 |
| Other property and equipment | | |
| Pipelines and processing facilities | 375,248 | 340,242 |
| General properties | 75,147 | 71,297 |
| Accumulated depreciation | (202,297) | (177,496) |
| Net other property and equipment | 248,098 | 234,043 |
| Property, plant and equipment, net of accumulated depletion and depreciation | $ 1,029,058 | $ 3,460,519 |

### Ceiling Test Analysis and Impairment

The charges for impairment are summarized below:

| | Segment | Pre-tax Charges for Impairment 2012 | 2011 | 2010 |
|---|---|---|---|---|
| | | | (in thousands) | |
| U.S. | | | | |
| Oil and gas properties | Exploration and production | $ 2,152,128 | $ — | $ — |
| Other property and equipment | Midstream | 7,328 | 57,996 | 28,611 |
| Other property and equipment | Exploration and production | 537,000 | — | — |
| Canada | | | | |
| Oil and gas properties | Exploration and production | 465,935 | 49,063 | 19,386 |
| | | $ 2,625,928 | $ 107,059 | $ 47,997 |

As described in Note 2, we are required to perform a quarterly ceiling test for impairment of our oil and gas properties in each of our cost centers. In 2012, we recognized impairment expense each quarter as the average of the first of month prices for the preceding 12 months declined each quarter. For our U.S. oil and gas properties, the Henry Hub price declined 33% from the price used at December 31, 2011 and the pricing used for NGLs declined 28% from the price used at December 31, 2011. For our Canadian oil and gas properties, the AECO price declined 36% from the price used at December 31, 2011. In 2012, the impairment on our oil and gas properties in both the U.S. and Canada was impacted by the exclusion of our derivatives from the ceiling test due to the discontinuance of hedge accounting. Other property and equipment impairment charges during 2012 were a result of reduced anticipated utilization of pipelines and facilities in Colorado and Texas and reduced use of a compressed natural gas facility in Texas.

The charge for impairment of our oil and gas properties in Canada in 2011 was recognized as a result of a 12% decrease in AECO natural gas price utilized in our Canadian ceiling test from December 31, 2010 to March 31, 2011. The charge for impairment of our oil and gas properties in Canada in 2010 was recognized as a result of significant changes in our Canadian cost center for the initial producing wells in our Horn River Asset and associated field costs while new proved reserves recognized were limited because of the short production history for the area.

In September 2010, our board of directors approved a plan for disposal of the HCDS. As a result of the decision, we conducted an impairment analysis of the HCDS and recognized a $28.6 million charge for impairment. During the third quarter of 2011, we discontinued our efforts to actively market the HCDS assets and re-assumed operating them from CMLP at which time we conducted a recovery test for impairment that did not result in an impairment charge. Based on decreased volumes and increased operating costs during the fourth quarter of 2011, we recognized additional impairment of $13.3 million determined on a market-based approach to fair value.

We also recognized an impairment charge of $44.7 million in 2011 related to certain Barnett Shale midstream assets to reduce their carrying value to estimated fair value as a result of decreased development by us and others in response to decreased natural gas prices during the fourth quarter. This decrease in current and forecasted development coupled with CMLP's inability to attract third parties to utilize their adjoining system are the underlying causes of the impairment. The resulting post-impairment carrying value equaled the discounted fair value of these assets' future cash flows.

**Unevaluated Natural Gas and Oil Properties Not Subject to Depletion**

Under full cost accounting, we may exclude certain unevaluated property costs from the amortization base pending determination of whether proved reserves have been discovered or impairment has occurred. A summary of the unevaluated properties not subject to depletion at December 31, 2012 and 2011 and the year in which they were incurred follows:

| | December 31, 2012 Costs Incurred During | | | | | December 31, 2011 Costs Incurred During | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | Prior | Total | 2011 | 2010 | 2009 | Prior | Total |
| | (In thousands) | | | | | (In thousands) | | | | |
| Acquisition costs | $ 7,177 | $ 42,339 | $ 2,090 | $ 112,917 | $ 164,523 | $ 119,936 | $ 39,307 | $ 8,408 | $ 126,756 | $ 294,407 |
| Exploration costs | 39,032 | 45,044 | 18,500 | 20,171 | 122,747 | 58,944 | 31,644 | 21,389 | 11,056 | 123,033 |
| Capitalized interest | 6,889 | 3,614 | 2,830 | 6,664 | 19,997 | 6,613 | 2,769 | 3,219 | 3,300 | 15,901 |
| Total | $ 53,098 | $ 90,997 | $ 23,420 | $ 139,752 | $ 307,267 | $ 185,493 | $ 73,720 | $ 33,016 | $ 141,112 | $ 433,341 |

The following table summarizes the regions where we have unevaluated property costs not subject to depletion.

| | As of December 31, | |
|---|---|---|
| | 2012 | 2011 |
| | (In thousands) | |
| Barnett Shale | $ 40,716 | $ 68,351 |
| West Texas | 49,318 | 49,750 |
| Horn River Basin | 217,233 | 180,604 |
| Sand Wash Basin | — | 132,965 |
| Other | — | 1,671 |
| Total | $ 307,267 | $ 433,341 |

Costs are transferred into the amortization base on an ongoing basis, as projects are evaluated and proved reserves established or impairment determined. Pending determination of proved reserves attributable to the above costs, we cannot assess the future impact on the amortization rate. Unevaluated acquisition costs will require up to an estimated seven more years of exploration and development activity before evaluation is complete, which is covered by the remaining primary term of the underlying leases.

**Other Matters**

Capitalized overhead costs that directly relate to exploration and development activities were $16.8 million, $18.3 million and $17.7 million for 2012, 2011 and 2010, respectively. Depletion per Mcfe was $1.07, $1.35 and $1.30 for 2012, 2011 and 2010, respectively. Depreciation expense was $18.6 million, $20.3 million and $35.0 million for 2012, 2011 and 2010, respectively.

## 9. OTHER ASSETS

Other assets consisted of the following:

| | As of December 31, 2012 | As of December 31, 2011 |
|---|---|---|
| | (In thousands) | |
| Deferred financing costs | $ 59,059 | $ 55,952 |
| Less accumulated amortization | (27,335) | (16,576) |
| Net deferred financing costs | 31,724 | 39,376 |
| Governmental and notes receivable | 7,385 | 7,996 |
| Other | 838 | 3,162 |
| | $ 39,947 | $ 50,534 |

Costs related to the acquisition of debt are deferred and amortized over the term of the debt.

## 10. ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

| | As of December 31, 2012 | As of December 31, 2011 |
|---|---|---|
| | (In thousands) | |
| Interest payable | $ 67,116 | $ 68,091 |
| Accrued operating expense | 38,733 | 46,569 |
| Prepayments from partners | — | 33 |
| Revenue payable | 21,013 | 26,073 |
| Accrued state income and franchise taxes | 1,183 | — |
| Accrued production and property taxes | 609 | 815 |
| Environmental liabilities | 122 | 63 |
| Accrued product purchases | 336 | 295 |
| Current asset retirement obligations | 577 | 254 |
| Other | 971 | — |
| | $ 130,660 | $ 142,193 |

## 11. LONG-TERM DEBT

Long-term debt consisted of the following:

| | As of December 31, 2012 | As of December 31, 2011 |
|---|---|---|
| | (In thousands) | |
| Combined Credit Agreements | $ 388,150 | $ 227,482 |
| Senior notes due 2015, net of unamortized discount of $2,149 and $2,980 | 435,851 | 435,020 |
| Senior notes due 2016, net of unamortized discount of $10,825 and $13,643 | 579,795 | 576,977 |
| Senior notes due 2019, net of unamortized discount of $5,378 and $5,945 | 292,622 | 292,055 |
| Senior subordinated notes due 2016 | 350,000 | 350,000 |
| Convertible debentures, net of unamortized discount | — | 18 |
| Total debt | 2,046,418 | 1,881,552 |
| Unamortized deferred gain—terminated interest rate swaps | 16,788 | 21,897 |
| Current portion of long-term debt | — | (18) |
| Long-term debt | $ 2,063,206 | $ 1,903,431 |

Maturities are as follows:

| | Total Indebtedness | Combined Credit Agreements | Senior Notes due in 2015 | Senior Notes due in 2016 | Senior Notes due in 2019 | Senior Subordinated Notes |
|---|---|---|---|---|---|---|
| | (in thousands) | | | | | |
| 2013 | $ — | $ — | $ — | $ — | $ — | $ — |
| 2014 | — | — | — | — | — | — |
| 2015 | 438,000 | — | 438,000 | — | — | — |
| 2016 | 1,328,770 | 388,150 | — | 590,620 | — | 350,000 |
| 2017 | — | — | — | — | — | — |
| Thereafter | 298,000 | — | — | — | 298,000 | — |
| | $ 2,064,770 | $ 388,150 | $ 438,000 | $ 590,620 | $ 298,000 | $ 350,000 |

*Credit Facilities*

During December 2011, the Initial U.S. Credit Facility and the Initial Canadian Credit Facility were amended and restated by the Combined Credit Agreements. The Combined Credit Agreements provide for an up to five-year combined revolving credit facility pursuant to which revolving credit loans and letters of credit may be provided to Quicksilver and Quicksilver Resources Canada Inc., as applicable, from time to time in an amount not to exceed the lesser of the borrowing base or commitments. The $1.75 billion Combined Credit Agreements had a global borrowing base of $1.075 billion, including a global letter of credit capacity of $175 million, as of December 31, 2011 which increased by $65 million at September 1, 2012. The Combined Credit Agreements' availability is governed by a global borrowing base. The global borrowing base and the U.S. borrowing base will be re-determined at least semi-annually based upon engineering reports and such other information deemed appropriate by the global administrative agent, in a manner consistent with its normal oil and gas lending criteria as it exists at the time of such redetermination. At the time of each such redetermination up to 100% of the U. S. borrowing base (less a $50 million minimum retained amount) may be allocated to the Canadian borrowing base. The commitments under each of the Amended and Restated U.S. Credit Facility and the Amended and Restated Canadian Credit Facility may be increased by an amount up to $250 million, subject to certain conditions including a commitment by one or more lenders.

In August 2012, in light of then prevailing prices for natural gas and NGLs, we amended our Combined Credit Agreements primarily to relax the financial covenants contained therein through the second quarter of 2014. The next semi-annual redetermination of our global borrowing base was scheduled to be completed in October 2012. However, in conjunction with the amendments to our Combined Credit Agreements, our global borrowing base was also redetermined and the next redetermination is scheduled for April 2013. As a result of the amendment and the redetermination process, the following changes were made to the Combined Credit Agreements:

- Reduction of the global borrowing base to $850 million from $1.075 billion
- Increase in the applicable margin by 0.50% for each type of loan and issued letters of credit, and setting of the commitment fee on unutilized availability to 0.50%
- Reduction of the minimum required interest coverage ratio from 2.5 to 1.5 for the quarter ending September 30, 2012 through the quarter ending March 31, 2014, then increasing to 2.0 for the quarter ending June 30, 2014, and reverting to 2.5 thereafter
- Addition of a required maximum senior secured debt leverage ratio of 2.5 beginning in the quarter ending September 30, 2012
- Until June 30, 2013, and so long as the total leverage ratio for the prior twelve month period is greater than or equal to 4.0:
  - Restrict the ability to issue certain additional types of debt;
  - Limit the aggregate amount of restricted payments to $15 million;
  - Restrict the ability to repay existing debt securities if global borrowing base utilization equals or exceeds 25%; and
  - Require a dollar for dollar repayment of the Combined Credit Agreements together with any repayment of existing debt securities if the global borrowing base utilization is less than 25% until the Combined Credit Agreements are paid in full, at which time existing debt securities may be repaid in any amounts; and
- Restrict the ability to terminate certain oil and gas hedging arrangements prior to December 31, 2014.

At December 31, 2012, there was $401.0 million available under the Combined Credit Agreements, including $179.2 million of available letter of credit capacity.

The Amended and Restated U.S. Credit Facility also provides for the extension of swingline loans to Quicksilver. Borrowings under the Amended and Restated U.S. Credit Facility bear interest at a variable annual rate based on adjusted LIBOR or ABR plus, in each case, an applicable margin, provided that each swingline loan shall be comprised entirely of ABR loans. Borrowings under the Amended and Restated Canadian Credit Facility may be made in U.S. dollars or Canadian dollars and will be comprised entirely of Canadian prime loans, Canadian Deposit Offer Rate ("CDOR") loans, U.S. prime loans or eurodollar loans, in each case, plus an applicable margin. The applicable margin under both credit facilities adjusts as the utilization of the global borrowing base changes.

Our ability to remain in compliance with the financial covenants in our Combined Credit Agreements may be affected by events beyond our control, including market prices for our products. Any future inability to comply with these covenants, unless waived or amended by the requisite lenders, could adversely affect our liquidity by rendering us unable to borrow further under our credit facilities and by accelerating the maturity of our indebtedness. Note 1 contains additional information regarding our ability to comply with our financial covenants.

*Senior Notes Due 2015*

In June 2008, we issued $475 million of senior notes due 2015, which are unsecured senior obligations of Quicksilver. The notes were issued at 98.66% of par. Interest at the rate of 8.25% is payable semiannually on February 1 and August 1.

*Senior Notes Due 2016*

In June 2009, we issued $600 million of senior notes due 2016, which are unsecured senior obligations of Quicksilver. The notes were issued at 96.72% of par, which resulted in proceeds of $580.3 million that were used to repay a portion of debt. Interest at the rate of 11.75% is payable semiannually on January 1 and July 1.

*Senior Notes Due 2019*

In August 2009, we issued $300 million of senior notes due 2019, which are unsecured senior obligations of Quicksilver. The notes were issued at 97.61% of par, which resulted in proceeds of $292.8 million that were used to repay a portion of our 2007 Senior Secured Credit Facility. Interest at the rate of 9.125% is payable semiannually on February 15 and August 15.

*Senior Subordinated Notes*

In 2006, we issued $350 million of senior subordinated notes due 2016. The senior subordinated notes are unsecured senior subordinated obligations and bear interest at the rate of 7.125% which is payable semiannually on April 1 and October 1.

*Indenture Restrictions*

We have an incurrence test under our indentures that requires EBITDA to exceed interest expense by 2.25 times. At December 31, 2012, we did not meet this test and, as a result, we are limited in our ability to, among other things, incur additional debt, except for specific baskets. We do retain, however, the ability to utilize the full borrowing capacity under our Combined Credit Agreements and to refinance existing debt. Not meeting this ratio does not represent an event of default in our indentures. We are presently unable to predict when or if we will meet the incurrence test.

*Senior Note Repurchases*

During 2011, we repurchased the following senior notes in open market transactions:

| Instrument | Repurchase Price | Face Value | Premium on Repurchase |
|---|---|---|---|
| | | (In thousands) | |
| Senior notes due 2015 | $ 38,134 | $ 37,000 | $ 1,134 |
| Senior notes due 2016 | 10,646 | 9,380 | 1,266 |
| Senior notes due 2019 | 2,160 | 2,000 | 160 |
| | $ 50,940 | $ 48,380 | $ 2,560 |

*Convertible Debentures*

The convertible debentures due November 1, 2024 were contingently convertible into shares of our common stock. On November 1, 2011, we repurchased substantially all of the debentures for $150 million, after they were presented to us for repurchase by debenture holders. The repurchase transaction was completed utilizing borrowings from the Initial U.S. Credit Facility. During the first quarter of 2012, we repurchased the remaining debentures.

For 2011 and 2010, interest expense on our convertible debentures, recognized at an effective interest rate of 6.75%, was $8.9 million and $10.2 million, respectively, including contractual interest of $2.3 million for 2011 and $2.8 million for 2010.

*Interest Expense*

Interest expense for the year ended December 31, 2012 was $164.1 million, net of capitalized interest of $18.4 million.

*Summary of All Outstanding Debt*

The following table summarizes certain significant aspects of our long-term debt outstanding at December 31, 2012:

| | ***Priority on Collateral and Structural Seniority*** [1] | | | | |
|---|---|---|---|---|---|
| | **Highest priority** | ← | | → | **Lowest priority** |
| | **Equal Priority** | **Equal priority** | | | |
| | **Combined Credit Agreements** | **2015 Senior Notes** | **2016 Senior Notes** | **2019 Senior Notes** | **Senior Subordinated Notes** |
| Principal amount [2] | $850 million | $438 million | $591 million | $298 million | $350 million |
| Scheduled maturity date | September 6, 2016 | August 1, 2015 | January 1, 2016 | August 15, 2019 | April 1, 2016 |
| Interest rate on outstanding borrowings at December 31, 2012 [3] | 3.36% | 8.25% | 11.75% | 9.125% | 7.125% |
| Base interest rate options | LIBOR, ABR, CDOR [4] [5] | N/A | N/A | N/A | N/A |
| Financial covenants [6] | - Minimum current ratio of 1.0<br>- Minimum EBITDA to cash interest expense ratio of 1.5<br>- Maximum senior secured debt leverage ratio of 2.5 | N/A | N/A | N/A | N/A |
| Significant restrictive covenants [6] | - Incurrence of debt<br>- Incurrence of liens<br>- Payment of dividends<br>- Equity purchases<br>- Asset sales<br>- Affiliate transactions<br>- Limitations on derivatives | - Incurrence of debt<br>- Incurrence of liens<br>- Payment of dividends<br>- Equity purchases<br>- Asset sales<br>- Affiliate transactions | - Incurrence of debt<br>- Incurrence of liens<br>- Payment of dividends<br>- Equity purchases<br>- Asset sales<br>- Affiliate transactions | - Incurrence of debt<br>- Incurrence of liens<br>- Payment of dividends<br>- Equity purchases<br>- Asset sales<br>- Affiliate transactions | - Incurrence of debt<br>- Incurrence of liens<br>- Payment of dividends<br>- Equity purchases<br>- Asset sales<br>- Affiliate transactions |
| Optional redemption [6] | Any time | August 1,<br>2012: 103.875<br>2013: 101.938<br>2014: par | July 1,<br>2013: 105.875<br>2014: 102.938<br>2015: par | August 15,<br>2014: 104.563<br>2015: 103.042<br>2016: 101.521<br>2017: par | April 1,<br>2012: 102.375<br>2013: 101.188<br>2014: par |
| Make-whole redemption [6] | N/A | N/A | Callable prior to July 1, 2013 at make-whole call price of Treasury + 50 bps | Callable prior to August 15, 2014 at make-whole call price of Treasury + 50 bps | N/A |
| Change of control [6] | Event of default | Put at 101% of principal plus accrued interest | Put at 101% of principal plus accrued interest | Put at 101% of principal plus accrued interest | Put at 101% of principal plus accrued interest |
| Estimated fair value [7] | $388.2 million | $411.7 million | $583.2 million | $272.3 million | $271.7 million |

(1) Borrowings under the Amended and Restated U.S. Credit Facility are guaranteed by certain of Quicksilver's domestic subsidiaries and are secured by 100% of the equity interests of each of Cowtown Pipeline Management, Inc., Cowtown Pipeline Funding, Inc., Cowtown Gas Processing L.P., Cowtown Pipeline L.P., Barnett Shale Operating LLC, Silver Stream Pipeline Company LLC, Quicksilver Production Partners Operating Ltd., QPP Parent LLC and QPP Holdings LLC (collectively, the "Domestic Pledged Equity"), 65% of the equity interests of Quicksilver Resources Canada Inc. ("Quicksilver Canada") (on a ratable basis with borrowings under the Amended and Restated Canadian Credit Facility) and the majority of Quicksilver's domestic proved oil and gas properties and related assets, (the "Domestic Pledged Property"). Borrowings under the Amended and Restated Canadian Credit Facility are guaranteed by Quicksilver and

certain of its domestic subsidiaries and are secured by the Domestic Pledged Equity, the Domestic Pledged Property, 100% of the equity interests of Quicksilver Canada (65% of which is on a ratable basis with the borrowings under the Amended and Restated U.S. Credit Facility) and any Canadian restricted subsidiaries, under the Amended and Restated Canadian Credit Facility and the majority of Quicksilver Canada's oil and gas properties and related assets. The other debt presented is based upon structural seniority and priority of payment.

(2) The principal amount for the Combined Credit Agreements represents the borrowing base as of December 31, 2012.

(3) Represents the weighted average borrowing rate payable to lenders.

(4) Amounts outstanding under the Amended and Restated U.S. Credit Facility bear interest, at our election, at (i) adjusted LIBOR (as defined in the Amended and Restated U.S. Credit Facility) plus an applicable margin between 2.00% to 3.00%, (ii) ABR (as defined in the Amended and Restated U.S. Credit Facility), which is the greatest of (a) the prime rate announced by JPMorgan, (b) the federal funds rate plus 0.50% and (c) adjusted LIBOR for an interest period of one month plus 1.00%, plus, in each case under scenario (ii), an applicable margin between 1.00% to 2.00%. We also pay a per annum fee on the LC Exposure (as defined in the Amended and Restated U.S. Credit Facility) of all letters of credit issued under the Amended and Restated U.S. Credit Facility equal to the applicable margin, with respect to adjusted LIBOR loans, and a commitment fee on the unused availability under the Amended and Restated U.S. Credit Facility of 0.50%.

(5) Amounts outstanding under the Amended and Restated Canadian Credit Facility bear interest, at our election, at (i) the CDOR Rate (as defined in the Amended and Restated Canadian Credit Facility) plus an applicable margin between 2.00% and 3.00%, (ii) the Canadian Prime Rate (as defined in the Amended and Restated Canadian Credit Facility) plus an applicable margin between 1.00% and 2.00%, (iii) the U.S. Prime Rate (as defined in the Amended and Restated Canadian Credit Facility) plus an applicable margin between 1.00% and 2.00% and (iv) adjusted LIBOR (as defined in the Amended and Restated Canadian Credit Facility) plus an applicable margin between 2.00% to 3.00%. We pay a per annum fee on the LC Exposure (as defined in the Amended and Restated Canadian Credit Facility) of all letters of credit issued under the Amended and Restated Canadian Credit Facility equal to the applicable margin, with respect to adjusted LIBOR loans, and a commitment fee on the unused availability under the Amended and Restated Canadian Credit Facility of 0.50%.

(6) The information presented in this table is qualified in all respects by reference to the full text of the covenants, provisions and related definitions contained in the documents governing the various components of our debt.

(7) The estimated fair value is determined using market quotations based on recent trade activity for fixed rate obligations ("Level 2" inputs). We consider debt with variable interest rates to have a fair value equal to its carrying value ("Level 1" input).

## 12. ASSET RETIREMENT OBLIGATIONS

The following table provides a reconciliation of the changes in the estimated asset retirement obligation from January 1, 2011 through December 31, 2012.

| | As of December 31, | |
|---|---|---|
| | 2012 | 2011 |
| | (In thousands) | |
| Beginning asset retirement obligations | $ 85,822 | $ 57,809 |
| Additional liability incurred | 4,072 | 6,134 |
| Change in estimates | 21,080 | 20,573 |
| Accretion expense | 4,122 | 2,696 |
| Asset retirement costs incurred | (1,846) | (2,857) |
| Gain on settlement of liability | 2,229 | 816 |
| Reclassification of liability of operations previously held for sale | — | 1,431 |
| Currency translation adjustment | 1,047 | (780) |
| Ending asset retirement obligations | 116,526 | 85,822 |
| Less current portion | (577) | (254) |
| Long-term asset retirement obligation | $ 115,949 | $ 85,568 |

## 13. INCOME TAXES

Significant components of our deferred tax assets and liabilities as of December 31, 2012 and 2011 are as follows:

| | As of December 31, 2012 | As of December 31, 2011 |
|---|---|---|
| | (In thousands) | |
| Deferred tax assets: | | |
| Property, plant and equipment | $ 483,771 | $ — |
| Net operating loss carry-forwards | 109,100 | 136,492 |
| Investment in Fortune Creek | 3,763 | 3,681 |
| AMT tax credit | 55,814 | 62,067 |
| Settlements of interest rate swaps | 5,876 | 7,664 |
| Deferred compensation expense | 11,141 | 17,865 |
| Other | 2,710 | 589 |
| Deferred tax assets | 672,175 | 228,358 |
| Deferred tax liabilities: | | |
| Property, plant and equipment | — | (420,564) |
| Gains from hedging and derivative activities | (65,163) | (95,373) |
| Unrealized gains reported in earnings | (8,032) | (12,999) |
| Deferred tax liabilities | (73,195) | (528,936) |
| Net deferred tax asset (liability) | 598,980 | (300,578) |
| Valuation allowance | (598,980) | (3,681) |
| Total deferred tax asset (liability) | $ — | $ (304,259) |
| Reflected in the consolidated balance sheets as: | | |
| Current deferred income tax liability | $ — | $ (45,262) |
| Non-current deferred income tax liability | — | (258,997) |
| | $ — | $ (304,259) |

The components of net income (loss) before income tax for 2012, 2011 and 2010 are as follows:

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| | | (In thousands) | |
| U.S. | $ (2,142,730) | $ 146,090 | $ 708,081 |
| Canada | (505,446) | 1,819 | 5,747 |
| Total | $ (2,648,176) | $ 147,909 | $ 713,828 |

No rate changes occurred in any taxing jurisdiction for 2010, 2011 or 2012. For 2013 and beyond, we have utilized a rate of 25% in Canada and a federal rate of 35% and a state rate of 1% in the U.S. to value our deferred tax positions, with the U.S. federal and state future rates mirroring existing applicable rates.

The components of income tax expense for 2012, 2011 and 2010 are as follows:

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| | | (In thousands) | |
| Current state income tax expense (benefit) | $ 1,752 | $ (1,706) | $ 4,501 |
| Current U.S. federal income tax expense (benefit) | — | (5,565) | 67,632 |
| Current Canadian income tax expense | — | 642 | 1,038 |
| Total current income tax expense (benefit) | 1,752 | (6,629) | 73,171 |
| Deferred state income tax expense | — | 1,980 | 3,674 |
| Deferred U.S. federal income tax expense (benefit) | (763,639) | 58,890 | 179,400 |
| U.S. federal valuation allowance expense | 533,974 | — | — |
| Deferred Canadian income tax expense (benefit) | (128,982) | 3,622 | 2,293 |
| Canadian valuation allowance expense | 61,325 | — | — |
| Total deferred income tax expense (benefit) | (297,322) | 64,492 | 185,367 |
| Total income tax expense (benefit) | $ (295,570) | $ 57,863 | $ 258,538 |

The following table reconciles the statutory federal income tax rate to the effective tax rate for 2012, 2011 and 2010:

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| U.S. federal statutory tax rate | 35.00 % | 35.00% | 35.00 % |
| Permanent differences | (0.06)% | 1.51% | 0.78 % |
| Noncontrolling interest benefit (expense) | — % | —% | (0.48)% |
| State income taxes net of federal deduction | (0.04)% | 0.12% | 0.74 % |
| Canadian income taxes | (1.93)% | 2.41% | 0.18 % |
| Other | 0.67 % | 0.08% | — % |
| Valuation allowance | (22.48)% | —% | — % |
| Effective income tax rate | 11.16 % | 39.12% | 36.22 % |

We incurred net operating tax losses of $1 million and $336 million in 2012 and 2009, respectively. We have utilized approximately $26 million of the net operating tax losses in 2011. The remaining $298 million is included in deferred tax assets, net of deferred tax benefits related to excess stock-based compensation deductions, at December 31, 2012. Our net operating losses will expire between 2029 and 2032.

During 2012, we recognized a U.S. and Canadian valuation allowance of $534.0 million and $61.3 million, respectively, as we determined that it is no longer more likely than not that we will realize the deferred tax benefits primarily related to our cumulative net operating losses. Additionally, our basis in the Fortune Creek Partnership exceeds book basis by $29 million. We expect to realize the deferred tax asset related to this balance only through the Partnership's sale at which time the transaction will be treated as a capital transaction under Canadian tax law, taxed at the Canadian statutory rate of 12.5% for capital gains. We believe that it is more likely than not that we will be unable to realize the benefit of this deferred tax asset. Accordingly in 2011, we recorded a full valuation allowance of $3.7 million for this item.

During October 2009, the IRS commenced an audit of our 2007 and 2008 consolidated U.S. federal income tax returns. No significant adjustments have been proposed by the IRS for those years. The Joint Committee of Taxation has reviewed and accepted the net operating loss carrybacks we filed in 2009. Net operating tax losses generated in the tax year are potentially subject to adjustment by federal tax authorities in the tax year which they are utilized.Our 2008 net operating tax losses were fully utilized in 2011, thus our 2008 year remains subject to audit.

The following schedule reconciles the total amounts of unrecognized tax benefits for 2012 and 2011:

| | As of December 31, 2012 | As of December 31, 2011 |
|---|---|---|
| | (In thousands) | |
| Beginning unrecognized tax benefits | $ 9,219 | $ 9,219 |
| Changes | (9,219) | — |
| Ending unrecognized tax benefits | $ — | $ 9,219 |

Tax benefits of $9.2 million were recognized during the quarter ended September 30, 2012 as the statute of limitations related to uncertain tax positions expired.

## 14. COMMITMENTS AND CONTINGENCIES

*Contractual Obligations*

Information regarding our contractual obligations, at December 31, 2012, is set forth in the following table:

| | GPT Contracts (1) | Drilling Rig Contracts (2) | Operating Leases (3) | Purchase Obligations (4) |
|---|---|---|---|---|
| | (In thousands) | | | |
| 2013 | $ 85,513 | $ 3,171 | $ 4,723 | $ 5,004 |
| 2014 | 78,559 | — | 4,568 | 168 |
| 2015 | 80,793 | — | 4,487 | 31 |
| 2016 | 92,058 | — | 4,221 | — |
| 2017 | 87,658 | — | 4,156 | — |
| Thereafter | 377,837 | — | 17,145 | — |
| Total | $ 802,418 | $ 3,171 | $ 39,300 | $ 5,203 |

(1) Under contracts with various third parties, we are obligated to provide minimum daily natural gas volume for gathering, processing, fractionation and transportation, as determined on a monthly basis, or pay for any deficiencies at a specified reservation fee rate. Our gathering and transportation contracts with CMLP have no minimum volume requirement and, therefore, are not reported in the above amounts.

(2) We lease drilling rigs from third parties for use in our development and exploration programs. The outstanding drilling rig contracts require payment of a specified day rate ranging from $6,005 to $12,500 for the entire lease term regardless of our utilization of the drilling rigs.

(3) We lease office buildings and other property under operating leases. Rent expense for operating leases with terms exceeding one month was $4.2 million in 2012, $4.8 million in 2011 and $4.3 million in 2010.

(4) At December 31, 2012, we were under contract to purchase goods and services for use in field and gas plant operations.

*Commitments and Contingencies*

In April 2011, we entered into the Komie North Project, which will serve our Horn River Asset. Under the governing agreements, we agreed to provide financial assurances in the form of letters of credit to NGTL during the construction phase of the project, which is now expected to continue through 2015.

On September 7, 2012, we entered into a Project Expenditure Authorization (PEA) Amending Agreement with NGTL to delay the targeted in-service date of the NGTL project pipeline and meter station facilities from May 1, 2014 to August 1, 2015. This amendment revised NGTL's spend profile, and correspondingly changed the timing of our financial assurances. Due to this delay, our letters of credit provided decreased from C$68.3 million to C$29.7 million. No additional letters of credit are scheduled to be provided until April 1, 2014.

Assuming the project is fully constructed and based on estimated costs of C$296.8 million, including taxes, we expect to provide cumulative letters of credit as follows:

| | NGTL Cumulative Financial Assurances [(1)] | | | |
|---|---|---|---|---|
| | (C$ in thousands) | | (US$ in thousands) | |
| April 1, 2014 | $ | 59,360 | $ | 59,663 |
| July 1, 2014 | | 148,400 | $ | 149,157 |
| September 1, 2014 | | 296,800 | $ | 298,314 |

(1) A letter of credit for C$29.7 million is outstanding for the Komie North Project as of December 31, 2012.

Should other companies subscribe to the project, then our financial assurances under the agreements will be reduced. If the project is terminated by NGTL, then we would be responsible for all of the costs incurred or for which NGTL is liable, and we would have the option to purchase NGTL's rights in the project for a nominal fee. Should the project be terminated by NGTL, we are required to pay NGTL an additional C$26.4 million. NGTL may terminate the project if it is not approved by the NEB of Canada. Based on this and on numerous other factors, we consider the likelihood to be remote that NGTL will terminate the project. Subsequent to the determination by the NEB to recommend against the Komie North Project, NGTL agreed to reduce our letter of credit to $14 million and based on discussions with NGTL we believe that NGTL will pursue its application on a delayed basis, but will not require payment of the C$26.4 million. In pursuing the application, NGTL will solicit the participation of other producers in the area. Accordingly, no amounts have been recognized on our consolidated balance sheet as of December 31, 2012. Upon completion of the project, all construction-related financial assurances will expire.

We also entered into agreements to deliver production from our Horn River Asset to NGTL over a 10-year period. These agreements will be extended in the event NGTL has either not received 1 Tcf of gas from us and other third parties, or recovered its costs as of the end of the 10-year period. In such event, the extension will be for delivery of minimum volumes of 106 MMcfd until such time that 1 Tcf of gas is delivered.

Also under the agreements, we are required to treat the gas to meet NGTL pipeline specifications. Such treatment will require us to construct treating facilities. We will develop our plans to address the treating requirements prior to the commissioning of the assets being constructed by NGTL.

At December 31, 2012, we had $8.9 million in surety bonds issued to fulfill contractual, legal or regulatory requirements and $60.8 million in letters of credit outstanding against the credit facility. Surety bonds and letters of credit generally have an annual renewal option.

As a result of our partial working interest sale to Eni in 2009, we entered into a joint development agreement with Eni. The joint development agreement includes a schedule of wells that we agreed to drill and complete with participation by Eni during the development period. In connection with the scheduled drilling of these wells, we have committed to drill and complete a minimum number of lateral feet each year. Eni agreed to pay us a turnkey drilling and completion cost of $994 per linear foot attributable to Eni. Through December 31, 2012 we had cumulatively completed 164,184 linear feet under the agreement, compared with a contract minimum of 157,717 feet. A total of 191,819 linear feet is required to be completed. Under the joint development agreement, we may be obligated to pay Eni for damages at the end of the development period should we fail to meet the linear footage requirements and certain production requirements have not been satisfied. We currently expect to satisfy these requirements and have recognized no liability related to non-performance.

On July 26, 2011, we received a subpoena duces tecum from the SEC requesting certain documents. The SEC has informed us that their investigation arises out of press releases in 2011 questioning the projected decline curves and economics of shale gas wells. On June 15, 2012, we received an additional request from the SEC for certain information regarding our assessment for impairment of unevaluated properties and plans for development of unevaluated properties. We provided responsive information and in February 2013 we met with the SEC.

On December 18, 2012, Vantage Fort Worth Energy LLC ("Vantage") served a lawsuit against us and others in the 352nd Judicial District Court of Texas in Tarrant County, Texas asserting claims for trespass to try title, suit to quiet title, trespass and conversion in connection with 16 wells located on a 158.75 acre tract in Tarrant County, Texas. They seek declaratory and injunctive relief, an accounting and an unspecified amount of actual damages, interest and court costs. We filed our answer on January 14, 2013. On January 28, 2013, Vantage filed its Motion for Non-suit with respect to certain defendants and First Amended Petition. Vantage's current complaint also seeks an unspecified amount of actual damages, interest and costs. We plan a vigorous defense in this matter.

We are subject to various proceedings and claims that arise in the ordinary course of business. While many of these matters involve inherent uncertainty, we believe, individually or in the aggregate, such matters will not have a material adverse impact on our financial position, results of operations or cash flows. Because of the uncertainty, our assessment may change in the future. If an unfavorable final outcome were to become probable or occur, it may have a material impact on our financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable.

*Environmental Compliance*

Our operations are subject to stringent, complex and changing laws and regulations pertaining to health, safety and the environment. As an owner, lessor or operator of our facilities, we are subject to laws and regulations at the federal, state, provincial and local levels that relate to air and water quality, hazardous and solid waste management and disposal and other environmental matters. The cost of planning, designing, constructing and operating our facilities incorporates compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures. At December 31, 2012, we had recorded $0.1 million for liabilities for environmental matters.

## 15. NONCONTROLLING INTERESTS AND KGS

KGS issued 4,000,000 common units in December 2009 in the KGS Secondary Offering and received $80.3 million, net of underwriters' discount and other offering costs. The portion of these proceeds related to our initial ownership interests, $50.2 million, was recognized as an increase to "Additional Paid-in Capital" on our consolidated balance sheet. In January 2010, the underwriters exercised their option to purchase an additional 549,200 common units for $11.1 million. As a result we recognized an additional $6.7 million to "Additional Paid-in Capital" in January 2010. KGS offered additional units to the public to provide funding for its acquisition of certain midstream assets from us, which was completed in January 2010 for $95.2 million.

With the closing of the Crestwood Transaction, we no longer consolidate KGS (or CMLP as it is now known) in our financial statements. Accordingly, we no longer have noncontrolling interests attributable to it within our financial statements.

## 16. FORTUNE CREEK

In December 2011, we entered into an agreement with KKR to form Fortune Creek to construct and operate midstream assets for natural gas produced by us and others primarily in British Columbia. The partnership established an area of mutual interest for the midstream business covering approximately 30 million potential acres which includes transportation and processing infrastructure and agreements.

In forming Fortune Creek, our Canadian subsidiary contributed an existing 20-mile, 20-inch gathering line and its related compression facilities and committed to minimum expenditures of $300 million for drilling and completion activities in our Horn River Asset between 2012 and 2014, of which we have incurred $147.3 million as of December 31, 2012, and will be required to incur an additional $32.7 million by December 31, 2013, with the balance of the $300 million to be incurred by December 31, 2014. Additionally, we committed gas production from our Horn River Asset for ten years beginning 2012, as more fully described below. KKR contributed $125 million cash in exchange for a 50% interest in Fortune Creek. Our Canadian subsidiary has responsibility for the day-to-day operations of Fortune Creek.

Our Canadian subsidiary entered into a firm gathering agreement with Fortune Creek which is guaranteed by us. At our election, KKR has the responsibility to fund up to $130 million of the capital required for construction of a new gas treatment facility in exchange for preferential cash flow distributions. If our subsidiary does not meet its obligations under the gathering agreement, KKR has the right to liquidate the partnership and consequently we have recorded the funds contributed by KKR as a liability in our consolidated financial statements. We recognize accretion expense to reflect the rate of return earned by KKR via its investment. Beginning in May 2012, Fortune Creek made cash distributions to KKR, which is reported as cash used by financing activities.

Based on an analysis of the partners' equity at risk, we have determined the partnership to be a VIE. Further, based on our ability to direct the activities surrounding the production of natural gas and our direct management of the operations of the Fortune Creek facilities, we have determined we are the primary beneficiary and, therefore, we consolidate Fortune Creek.

Note 19 contains financial information for Fortune Creek in our condensed consolidating financial statements.

## 17. QUICKSILVER STOCKHOLDERS' EQUITY

### Common Stock, Preferred Stock and Treasury Stock

We are authorized to issue 400 million shares of common stock with a $0.01 par value per share and 10 million shares of preferred stock with a $0.01 par value per share. At December 31, 2012, we had 173 million shares of common stock outstanding.

The following table shows common share and treasury share activity since January 1, 2010:

| | Common Shares Issued | Treasury Shares Held |
|---|---|---|
| Balance at January 1, 2010 | 174,469,836 | 4,704,448 |
| Stock options exercised | 336,629 | 16,908 |
| Restricted stock activity | 718,351 | 329,094 |
| Balance at December 31, 2010 | 175,524,816 | 5,050,450 |
| Stock options exercised | 209,221 | — |
| Restricted stock activity | 1,246,446 | 329,252 |
| Balance at December 31, 2011 | 176,980,483 | 5,379,702 |
| Stock options exercised | 1,572 | — |
| Restricted stock activity | 2,033,063 | 541,400 |
| Balance at December 31, 2012 | 179,015,118 | 5,921,102 |

### Quicksilver Stockholder Rights Plan

In 2003, our Board of Directors declared a dividend distribution of one preferred share purchase right for each share of common stock then outstanding. Pursuant to the amendments entered into on March 8, 2013, each right, when it becomes exercisable, entitles stockholders to buy one one thousandth of a share of Quicksilver's Series A Junior Participating Preferred Stock at an exercise price of $10, subject to customary anti-dilution adjustments.

The rights will be exercisable only if such a person or group acquires 15% or more of our common stock or announces a tender offer the consummation of which would result in ownership by such a person or group (an "Acquiring Person") of 15% or more of our common stock. This 15% threshold does not apply to certain members of the Darden family and affiliated entities (the "Darden Entities"), which collectively owned, directly or indirectly, approximately 30% of our common stock at February 28, 2013, so long as the Darden Entities do not acquire beneficial ownership of additional shares of our common stock, subject to certain exceptions and subject to the Darden Entities, collectively, being able to acquire additional shares of common stock to maintain the Darden Entities' collective percentage ownership in us.

If an Acquiring Person acquires 15% or more of our outstanding common stock (or any Darden Entity exceeds the thresholds applicable to the Darden Entities), each right (other than the rights of the Acquiring Person, including, if applicable, the Darden Entities) will entitle its holder to purchase, at the right's then-current exercise price, a number of our common shares having a market value of twice such price. If we are acquired in a merger or other business combination transaction after an Acquiring Person has acquired 15% or more of our outstanding common stock (or any Darden Entity has exceeded the thresholds applicable to the Darden Entities), each right (other than the rights of the Acquiring Person, including, if applicable, the Darden Entities) will entitle its holder to purchase, at the right's then-current exercise price, a number of the acquiring company's common shares having a market value of twice such price.

Prior to the acquisition by an Acquiring Person of beneficial ownership of 15% or more of our common stock (or any Darden Entity exceeds the thresholds applicable to the Darden Entities), the rights are redeemable for $0.01 per right at the option of our Board of Directors.

The rights plan will expire by its terms on March 11, 2016.

### Stock-Based Compensation

*2006 Equity Plan*

In 2006, our Board of Directors and our stockholders approved the 2006 Equity Plan, under which 14 million shares of common stock were reserved for issuance as grants of stock options, appreciation rights, restricted shares, restricted stock units, performances shares, performance units and senior executive plan bonuses. In May 2009, our stockholders approved an amendment to the 2006 Equity Plan, which increased the number of shares available for issuance to 15 million. Our executive officers, other employees, consultants and non-employee directors are eligible to participate in the 2006 Equity Plan. Options reflect an exercise price of no less than the fair market value on the date of grant and have a term that expires ten years from the date of grant. At December 31, 2012 and 2011, 9.7 million shares and 12.6 million shares (including 1.4 million shares and 0.9 million shares, respectively, surrendered to us to satisfy participants' tax withholding obligations which then became available for future issuance under the 2006 Equity Plan), respectively, were available for issuance under the 2006 Equity Plan.

*Stock Options*

The following summarizes the values from and assumptions for the Black-Scholes option pricing model:

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| Weighted average grant date fair value | $4.21 | $9.16 | $9.88 |
| Weighted average risk-free interest rate | 1.14% | 2.38% | 3.00% |
| Expected life (in years) | 6.0 | 6.0 | 6.0 |
| Weighted average volatility | 68.20% | 66.77% | 66.76% |
| Expected dividends | — | — | — |

The following table summarizes our stock option activity for 2012:

| | Shares | Weighted Average Exercise Price | Weighted Average Remaining Contractual Life | Aggregate Intrinsic Value |
|---|---|---|---|---|
| | | | (In years) | (In thousands) |
| Outstanding at January 1, 2012 | 3,760,696 | $ 12.01 | | |
| Granted | 2,020,685 | 6.90 | | |
| Exercised | (1,572) | 6.21 | | |
| Cancelled | (472,846) | 8.83 | | |
| Expired | (326,983) | 12.14 | | |
| Outstanding at December 31, 2012 | 4,979,980 | $ 10.23 | 7.0 | $ — |
| Exercisable at December 31, 2012 | 2,921,756 | $ 10.88 | 5.9 | $ — |

We estimate that a total of 5.0 million stock options will become vested including those options already exercisable. The unexercised options have a weighted average exercise price of $10.22 and a weighted average remaining contractual life of 7 years.

As of December 31, 2012 the unrecognized compensation cost related to outstanding unvested options was $6.1 million, which is expected to be recognized in expense over the next two years. Compensation expense related to stock options of $7.4 million, $7.0 million and $6.7 million was recognized for 2012, 2011 and 2010, respectively. The income tax benefit recognized in income related to this compensation expense was $2.4 million in 2012. The total intrinsic value of options exercised during 2012, 2011 and 2010, was $0.1 million, $1.2 million and $2.8 million, respectively.

*Restricted Stock and Stock Units*

The following table summarizes our restricted stock and stock unit activity for 2012:

| | Payable in shares | | Payable in cash | |
|---|---|---|---|---|
| | Shares | Weighted Average Grant Date Fair Value | Shares | Weighted Average Grant Date Fair Value |
| Outstanding at January 1, 2012 | 2,460,300 | $ 12.29 | 369,846 | $ 13.12 |
| Granted | 3,282,465 | 6.13 | 653,195 | 6.19 |
| Vested | (1,776,548) | 9.20 | (199,068) | 11.31 |
| Cancelled | (867,082) | 8.93 | (145,756) | 9.66 |
| Outstanding at December 31, 2012 | 3,099,135 | $ 8.48 | 678,217 | $ 7.71 |

As of December 31, 2012, the unrecognized compensation cost related to outstanding unvested restricted stock and RSUs was $14.9 million, which is expected to be recognized in expense over the next 2 years. Grants of restricted stock and RSUs during 2012 had an estimated grant date fair value of $24.2 million. The fair value of RSUs settled in cash was $1.9 million and $2.5 million at December 31, 2012 and 2011, respectively. For 2012, 2011 and 2010, compensation expense of $15.7 million, $13.9 million and $13.3 million, respectively, was recognized. The income tax benefit recognized in income related to this compensation expense was $5.2 million in 2012. The total fair value of shares vested during 2012, 2011 and 2010 was $16.3 million, $13.6 million and $16.4 million, respectively.

**Accumulated Other Comprehensive Income**

At December 31, 2012, AOCI included $141.4 million, net of tax, and $20.1 million for derivatives and foreign currency translation, respectively. At December 31, 2011, AOCI included $195.2 million, net of tax, and $19.7 million for derivatives and foreign currency translation, respectively. All of these balances were attributable to us.

## 18. EARNINGS PER SHARE

The following is a reconciliation of the numerator and denominator used for the computation of basic and diluted net income per common share.

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | (In thousands, except per share data) | | |
| Net income (loss) attributable to Quicksilver | $ (2,352,606) | $ 90,046 | $ 445,566 |
| Basic income allocable to participating securities [1] | — | (1,106) | (5,698) |
| Basic net income (loss) attributable to Quicksilver | $ (2,352,606) | $ 88,940 | $ 439,868 |
| Impact of assumed conversions — interest on 1.875% convertible debentures, net of income taxes [2] | — | — | 7,194 |
| Income (loss) available to stockholders assuming conversion of convertible debentures | $ (2,352,606) | $ 88,940 | $ 447,062 |
| Weighted average common shares — basic | 170,106 | 168,993 | 168,010 |
| Effect of dilutive securities [2]: | | | |
| Share-based compensation awards | — | 742 | 802 |
| Convertible debentures | — | — | 9,816 |
| Weighted average common shares — diluted | 170,106 | 169,735 | 178,628 |
| Earnings (loss) per common share — basic | $ (13.83) | $ 0.53 | $ 2.62 |
| Earnings (loss) per common share — diluted | $ (13.83) | $ 0.52 | $ 2.50 |

(1) Restricted share awards that contain nonforfeitable rights to dividends are participating securities and, therefore, should be included in computing earnings using the two-class method. Participating securities, however, do not participate in undistributed net losses because there is no contractual obligation to do so.

(2) For 2012, the effects of 5.0 million shares associated with our stock options and 0.3 million shares associated with our unvested restricted stock units were antidilutive and, therefore, excluded from the diluted share calculations. For 2011, the effects of 9.8 million shares associated with our convertible debentures for the period outstanding were antidilutive, and stock options and unvested restricted stock units representing 1.9 million and 0.1 million shares, respectively, were antidilutive and, therefore, excluded from the diluted share calculations. For 2010, stock options and unvested restricted stock units representing 1.2 million and 0.1 million shares, respectively, were antidilutive and, therefore, excluded from the diluted share calculations.

## 19. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The following tables provide information about the entities that guarantee our senior notes and senior subordinated notes. The guarantees are full and unconditional and joint and several.

Under SEC rules, we are required to present financial information segregated between our guarantor and non-guarantor subsidiaries. The indentures under both our senior notes and our senior subordinated notes distinguish between "restricted" subsidiaries and "unrestricted" subsidiaries and further specify supplemental information that is not required under GAAP. The following table illustrates our subsidiaries and their status pursuant to the senior notes due 2015, senior notes due 2016, senior notes due 2019 and the senior subordinated notes:

| Guarantor Subsidiaries - Restricted | Non-Guarantor Subsidiaries | |
|---|---|---|
| | **Restricted** | **Unrestricted** |
| Cowtown Pipeline Funding, Inc. | Quicksilver Resources Canada Inc. | Quicksilver Gas Services Holdings LLC (2) |
| Cowtown Pipeline Management, Inc. | Cowtown Drilling Inc. (1) | Quicksilver Gas Services GP LLC (2) |
| Cowtown Pipeline L.P. | Quicksilver Resources Partners Operating Ltd. (3) | Quicksilver Gas Services LP (2) |
| Cowtown Gas Processing L.P. | 0942065 B.C. Ltd. (4) | Quicksilver Gas Services Operating LLC (2) |
| Barnett Shale Operating LLC (3) | 0942069 B.C Ltd. (4) | Quicksilver Gas Services Operating GP LLC (2) |
| QPP Parent LLC (4) | | Cowtown Pipeline Partners L.P. (2) |
| QPP Holdings LLC (4) | | Cowtown Gas Processing Partners L.P. (2) |
| Silver Stream Pipeline Company LLC (4) | | Makarios Resources International Holdings LLC (3) |
| | | 1622834 Alberta Inc. (3) |
| | | Makarios Midstream Inc. (3) |
| | | Makarios Resources International Inc. (3) |
| | | Quicksilver Production Partners GP LLC (3) |
| | | Quicksilver Production Partners LP (3) |

(1) This entity was inactive for the three-year period ended December 31, 2012.

(2) We sold all our interests in this entity to Crestwood on October 1, 2010.

(3) These entities were created in 2011.

(4) These entities were created in 2012.

We own 100% of each of the restricted subsidiaries.

Quicksilver and the restricted subsidiaries conduct all of our exploration and production activities, and the unrestricted subsidiaries primarily conduct midstream operations or are related to our midstream MLP we sold in 2010. Neither the restricted non-guarantor subsidiaries nor the unrestricted non-guarantor subsidiaries guarantee the obligations under the senior notes or the senior subordinated notes.

However, the restricted non-guarantor subsidiaries, like the restricted guarantor subsidiaries, are limited in their activity by the covenants in the indentures for such matters as:

- incurring additional indebtedness;
- paying dividends;
- selling assets;
- making investments; and
- making restricted payments.

Subject to restrictions set forth in the indentures, we may in the future designate one or more additional subsidiaries as unrestricted.

The following tables present financial information about Quicksilver and our restricted subsidiaries for the annual periods covered by the consolidated financial statements. Under the indenture, Fortune Creek is not considered to be a subsidiary and therefore it is presented separately from the other subsidiaries for these purposes. The 2010 condensed consolidating financial information includes changes in the financial information of our unrestricted non-guarantor subsidiaries to present the 2010 financial information including the effects of the purchase of certain of our midstream assets by KGS and the Crestwood Transaction where we sold all of our interests in the unrestricted subsidiaries.

## Condensed Consolidating Balance Sheets

| | Quicksilver Resources Inc. | Restricted Guarantor Subsidiaries | Restricted Non-Guarantor Subsidiaries | Restricted Subsidiary Eliminations | Quicksilver and Restricted Subsidiaries | Unrestricted Non-Guarantor Subsidiaries | Fortune Creek | Consolidating Eliminations | Quicksilver Resources Inc. Consolidated |
|---|---|---|---|---|---|---|---|---|---|
| | **December 31, 2012** | | | | | | | | |
| | (In thousands) | | | | | | | | |
| ASSETS | | | | | | | | | |
| Current assets | $ 261,130 | $ 105,695 | $ 76,088 | $ (222,586) | $ 220,327 | $ 13,250 | $ 391 | $ (26,455) | $ 207,513 |
| Property and equipment | 621,073 | 20,007 | 296,462 | — | 937,542 | — | 91,516 | — | 1,029,058 |
| Investment in subsidiaries (equity method) | (191,725) | — | (42,883) | 191,725 | (42,883) | (42,905) | — | 85,788 | — |
| Other assets | 346,972 | — | 41,865 | (243,620) | 145,217 | — | — | — | 145,217 |
| Total assets | $ 1,037,450 | $ 125,702 | $ 371,532 | $ (274,481) | $ 1,260,203 | $ (29,655) | $ 91,907 | $ 59,333 | $ 1,381,788 |
| LIABILITIES AND EQUITY | | | | | | | | | |
| Current liabilities | $ 255,678 | $ 112,133 | $ 33,475 | $ (222,586) | $ 178,700 | $ 13,230 | $ 2,316 | $ (26,455) | $ 167,791 |
| Long-term liabilities | 1,914,568 | 19,242 | 524,107 | (243,620) | 2,214,297 | — | 1,585 | 130,912 | 2,346,794 |
| Quicksilver stockholders' equity | (1,132,796) | (5,673) | (186,050) | 191,725 | (1,132,794) | (42,885) | 88,006 | (45,124) | (1,132,797) |
| Total liabilities and equity | $ 1,037,450 | $ 125,702 | $ 371,532 | $ (274,481) | $ 1,260,203 | $ (29,655) | $ 91,907 | $ 59,333 | $ 1,381,788 |

| | Quicksilver Resources Inc. | Restricted Guarantor Subsidiaries | Restricted Non-Guarantor Subsidiaries | Restricted Subsidiary Eliminations | Quicksilver and Restricted Subsidiaries | Unrestricted Non-Guarantor Subsidiaries | Fortune Creek | Consolidating Eliminations | Quicksilver Resources Inc. Consolidated |
|---|---|---|---|---|---|---|---|---|---|
| | **December 31, 2011** | | | | | | | | |
| | (In thousands) | | | | | | | | |
| ASSETS | | | | | | | | | |
| Current assets | $ 336,893 | $ 87,767 | $ 63,711 | $ (200,727) | $ 287,644 | $ — | $ 27,533 | $ (14,750) | $ 300,427 |
| Property and equipment | 2,743,379 | 37,936 | 598,443 | — | 3,379,758 | — | 80,761 | — | 3,460,519 |
| Investment in subsidiaries (equity method) | 241,680 | — | (29,449) | (241,680) | (29,449) | (29,449) | — | 58,898 | — |
| Other assets | 401,279 | — | 76,857 | (243,620) | 234,516 | — | — | — | 234,516 |
| Total assets | $ 3,723,231 | $ 125,703 | $ 709,562 | $ (686,027) | $ 3,872,469 | $ (29,449) | $ 108,294 | $ 44,148 | $ 3,995,462 |
| LIABILITIES AND EQUITY | | | | | | | | | |
| Current liabilities | $ 348,512 | $ 109,938 | $ 76,450 | $ (200,727) | $ 334,173 | $ — | $ 14,750 | $ (14,750) | $ 334,173 |
| Long-term liabilities | 2,112,800 | 21,903 | 385,294 | (243,620) | 2,276,377 | — | 80 | 122,913 | 2,399,370 |
| Quicksilver stockholders' equity | 1,261,919 | (6,138) | 247,818 | (241,680) | 1,261,919 | (29,449) | 93,464 | (64,015) | 1,261,919 |
| Total liabilities and equity | $ 3,723,231 | $ 125,703 | $ 709,562 | $ (686,027) | $ 3,872,469 | $ (29,449) | $ 108,294 | $ 44,148 | $ 3,995,462 |

## Condensed Consolidating Statements of Income

| | For the Year Ended December 31, 2012 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Quicksilver Resources Inc. | Restricted Guarantor Subsidiaries | Restricted Non-Guarantor Subsidiaries | Restricted Subsidiary Eliminations | Quicksilver and Restricted Subsidiaries | Unrestricted Non-Guarantor Subsidiaries | Fortune Creek | Eliminations | Quicksilver Resources Inc. Consolidated |
| | (In thousands) | | | | | | | | |
| Revenue | $ 611,477 | $ 4,574 | $ 95,887 | $ (2,900) | $ 709,038 | $ — | $ 14,639 | $ (14,639) | $ 709,038 |
| Operating expenses | 2,643,690 | 4,109 | 577,696 | (2,900) | 3,222,595 | — | 7,940 | (14,639) | 3,215,896 |
| Crestwood earn-out | 41,097 | — | — | — | 41,097 | — | — | — | 41,097 |
| Equity in net earnings of subsidiaries | (437,510) | — | (12,747) | 437,510 | (12,747) | 6,726 | — | 6,021 | — |
| Operating income (loss) | (2,428,626) | 465 | (494,556) | 437,510 | (2,485,207) | 6,726 | 6,699 | 6,021 | (2,465,761) |
| Fortune Creek accretion | — | — | — | — | — | — | — | (19,472) | (19,472) |
| Interest expense and other | (152,077) | — | (10,914) | — | (162,991) | 21 | 27 | — | (162,943) |
| Income tax (expense) benefit | 228,097 | (163) | 67,658 | — | 295,592 | — | — | (22) | 295,570 |
| Net income (loss) | $ (2,352,606) | $ 302 | $ (437,812) | $ 437,510 | $ (2,352,606) | $ 6,747 | $ 6,726 | $ (13,473) | $ (2,352,606) |
| Other comprehensive income (loss) | (57,273) | — | 3,908 | (3,908) | (57,273) | — | — | — | (57,273) |
| Equity in OCI of subsidiaries | 3,908 | — | — | — | 3,908 | — | — | — | 3,908 |
| Comprehensive income (loss) | $ (2,405,971) | $ 302 | $ (433,904) | $ 433,602 | $ (2,405,971) | $ 6,747 | $ 6,726 | $ (13,473) | $ (2,405,971) |

| | For the Year Ended December 31, 2011 | | | | |
|---|---|---|---|---|---|
| | Quicksilver Resources Inc. | Restricted Guarantor Subsidiaries | Restricted Non-Guarantor Subsidiaries | Consolidating Eliminations | Quicksilver Resources Inc. Consolidated |
| | (In thousands) | | | | |
| Revenue | $ 778,741 | $ 4,573 | $ 163,864 | $ (3,555) | $ 943,623 |
| Operating expenses | 603,582 | 64,476 | 156,516 | (3,555) | 821,019 |
| Equity in net earnings of subsidiaries | (40,725) | — | — | 40,725 | — |
| Operating income (loss) | 134,434 | (59,903) | 7,348 | 40,725 | 122,604 |
| Income from earnings of BBEP | (8,439) | — | — | — | (8,439) |
| Interest expense and other | 39,252 | 18 | (5,526) | — | 33,744 |
| Income tax (expense) benefit | (75,201) | 20,960 | (3,622) | — | (57,863) |
| Net income (loss) | $ 90,046 | $ (38,925) | $ (1,800) | $ 40,725 | $ 90,046 |
| Other comprehensive income (loss) | 67,493 | — | 17,178 | (17,178) | 67,493 |
| Equity in OCI of subsidiaries | 17,178 | — | — | — | 17,178 |
| Comprehensive income (loss) | $ 174,717 | $ (38,925) | $ 15,378 | $ 23,547 | $ 174,717 |

| | For the Year Ended December 31, 2010 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Quicksilver Resources Inc. | Guarantor Subsidiaries | Restricted Non-Guarantor Subsidiaries | Restricted Subsidiary Eliminations | Quicksilver and Restricted Subsidiaries | Unrestricted Non-Guarantor Subsidiaries | Eliminations | Quicksilver Resources Inc. Consolidated |
| | (In thousands) | | | | | | | |
| Revenue | $ 788,714 | $ 6,863 | $ 126,322 | $ (3,197) | $ 918,702 | $ 82,299 | $ (72,670) | $ 928,331 |
| Operating expenses | 494,373 | 37,508 | 113,768 | (3,197) | 642,452 | 48,368 | (72,670) | 618,150 |
| Gain on sale of subsidiary | 493,953 | — | — | — | 493,953 | — | — | 493,953 |
| Equity in net earnings of subsidiaries | (7,666) | 15,228 | — | 7,666 | 15,228 | — | (15,228) | — |
| Operating income (loss) | 780,628 | (15,417) | 12,554 | 7,666 | 785,431 | 33,931 | (15,228) | 804,134 |
| Income from earnings of BBEP | 22,323 | — | — | — | 22,323 | — | — | 22,323 |
| Interest expense and other | (96,953) | — | (6,868) | — | (103,821) | (8,808) | — | (112,629) |
| Income tax (expense) benefit | (260,432) | 5,396 | (3,331) | — | (258,367) | (171) | — | (258,538) |
| Net income (loss) | $ 445,566 | $ (10,021) | $ 2,355 | $ 7,666 | $ 445,566 | $ 24,952 | $ (15,228) | $ 455,290 |
| Net income attributable to noncontrolling interests | — | — | — | — | — | (9,724) | — | (9,724) |
| Net income (loss) attributable to Quicksilver | $ 445,566 | $ (10,021) | $ 2,355 | $ 7,666 | $ 445,566 | $ 15,228 | $ (15,228) | $ 445,566 |
| Other comprehensive income (loss) | (20,199) | — | 29,050 | (29,050) | (20,199) | — | — | (20,199) |
| Equity in OCI of subsidiaries | 29,050 | — | — | — | 29,050 | — | — | 29,050 |
| Comprehensive income (loss) | $ 454,417 | $ (10,021) | $ 31,405 | $ (21,384) | $ 454,417 | $ 15,228 | $ (15,228) | $ 454,417 |

## Condensed Consolidating Statements of Cash Flows

| | For the Year Ended December 31, 2012 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Quicksilver Resources Inc. | Restricted Guarantor Subsidiaries | Restricted Non-Guarantor Subsidiaries | Quicksilver and Restricted Subsidiaries | Unrestricted Non-Guarantor Subsidiaries | Fortune Creek | Quicksilver Resources Inc. Consolidated |
| | (In thousands) | | | | | | |
| Net cash flow provided by operations | $ 163,353 | $ 656 | $ 49,271 | $ 213,280 | $ — | $ 14,447 | $ 227,727 |
| Capital expenditures | (231,934) | (656) | (242,158) | (474,748) | — | (10,731) | (485,479) |
| Proceeds from Crestwood earn-out | 41,097 | — | — | 41,097 | — | — | 41,097 |
| Proceeds from sale of properties and equipment | 72,362 | — | 363 | 72,725 | — | — | 72,725 |
| Net cash flow used by investing activities | (118,475) | (656) | (241,795) | (360,926) | — | (10,731) | (371,657) |
| Issuance of debt | 228,500 | — | 239,459 | 467,959 | — | — | 467,959 |
| Repayments of debt | (264,018) | — | (46,412) | (310,430) | — | — | (310,430) |
| Debt issuance costs | (1,972) | — | (1,050) | (3,022) | — | — | (3,022) |
| Distribution of Fortune Creek Partnership funds | — | — | — | — | — | (14,285) | (14,285) |
| Proceeds from exercise of stock options | 11 | — | — | 11 | — | — | 11 |
| Excess tax deductions on stock compensation | — | — | — | — | — | — | — |
| Purchase of treasury stock | (3,144) | — | — | (3,144) | — | — | (3,144) |
| Net cash flow provided (used) by financing activities | (40,623) | — | 191,997 | 151,374 | — | (14,285) | 137,089 |
| Effect of exchange rates on cash | — | — | 527 | 527 | — | (1,881) | (1,354) |
| Net increase (decrease) in cash and equivalents | 4,255 | — | — | 4,255 | — | (12,450) | (8,195) |
| Cash and equivalents at beginning of period | 363 | — | — | 363 | — | 12,783 | 13,146 |
| Cash and equivalents at end of period | $ 4,618 | $ — | $ — | $ 4,618 | $ — | $ 333 | $ 4,951 |

| | For the Year Ended December 31, 2011 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Quicksilver Resources Inc. | Restricted Guarantor Subsidiaries | Restricted Non-Guarantor Subsidiaries | Quicksilver and Restricted Subsidiaries | Fortune Creek | Consolidating Eliminations | Quicksilver Resources Inc. Consolidated |
| | (In thousands) | | | | | | |
| Net cash flow provided by operations | $ 202,043 | $ 2,225 | $ 48,785 | $ 253,053 | $ — | $ — | $ 253,053 |
| Capital expenditures | (518,454) | (2,225) | (169,928) | (690,607) | — | — | (690,607) |
| Proceeds from sale of BBEP units | 272,965 | — | — | 272,965 | — | — | 272,965 |
| Investment in Fortune Creek | — | — | (12,783) | (12,783) | — | 12,783 | — |
| Proceeds from sale of properties and equipment | 2,959 | — | 1,204 | 4,163 | — | — | 4,163 |
| Net cash flow used by investing activities | (242,530) | (2,225) | (181,507) | (426,262) | — | 12,783 | (413,479) |
| Issuance of debt | 587,500 | — | 268,322 | 855,822 | — | — | 855,822 |
| Repayments of debt | (588,862) | — | (254,246) | (843,108) | — | — | (843,108) |
| Debt issuance costs | (9,160) | — | (3,346) | (12,506) | — | — | (12,506) |
| Proceeds from exercise of stock options | 1,299 | — | — | 1,299 | — | — | 1,299 |
| Partnership funds received | — | — | — | — | 135,696 | (12,783) | 122,913 |
| Creation of partnership liability | — | — | 122,913 | 122,913 | (122,913) | — | — |
| Purchase of treasury stock | (4,864) | — | — | (4,864) | — | — | (4,864) |
| Net cash flow provided by financing activities | (14,087) | — | 133,643 | 119,556 | 12,783 | (12,783) | 119,556 |
| Effect of exchange rates on cash | — | — | (921) | (921) | — | — | (921) |
| Net increase (decrease) in cash and equivalents | (54,574) | — | — | (54,574) | 12,783 | — | (41,791) |
| Cash and equivalents at beginning of period | 54,937 | — | — | 54,937 | — | — | 54,937 |
| Cash and equivalents at end of period | $ 363 | $ — | $ — | $ 363 | $ 12,783 | $ — | $ 13,146 |

| | For the Year Ended December 31, 2010 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Quicksilver Resources Inc.** | **Restricted Guarantor Subsidiaries** | **Restricted Non-Guarantor Subsidiaries** | **Restricted Subsidiary Eliminations** | **Quicksilver and Restricted Subsidiaries** | **Unrestricted Non-Guarantor Subsidiaries** | **Eliminations** | **Quicksilver Resources Inc. Consolidated** |
| | (In thousands) | | | | | | | |
| Net cash flow provided by operations | $ 288,164 | $ 651 | $ 78,959 | $ — | $ 367,774 | $ 44,816 | $ (14,870) | $ 397,720 |
| Capital expenditures | (534,404) | (651) | (100,183) | — | (635,238) | (52,470) | (7,406) | (695,114) |
| Distribution to parent | 80,276 | — | — | — | 80,276 | (80,276) | — | — |
| Proceeds from sale of KGS | 699,973 | — | — | — | 699,973 | — | — | 699,973 |
| Proceeds from sale of BBEP units | 34,016 | — | — | — | 34,016 | — | — | 34,016 |
| Proceeds from sale of properties and equipment | 9,953 | — | — | — | 9,953 | — | — | 9,953 |
| Net cash flow used for investing activities | 289,814 | (651) | (100,183) | — | 188,980 | (132,746) | (7,406) | 48,828 |
| Issuance of debt | 478,500 | — | 68,358 | — | 546,858 | 143,200 | — | 690,058 |
| Repayments of debt | (712,000) | — | (289,636) | — | (1,001,636) | (30,100) | — | (1,031,736) |
| Debt issuance costs | (2,211) | — | (900) | — | (3,111) | — | — | (3,111) |
| Gas Purchase Commitment repayments | (44,119) | — | — | — | (44,119) | — | — | (44,119) |
| Issuance of KGS common units | — | — | — | — | — | 11,054 | — | 11,054 |
| Distributions to parent | — | — | — | — | — | (22,276) | 22,276 | — |
| Intercompany note | (243,620) | — | 243,620 | — | — | — | — | — |
| Distributions to noncontrolling interests | — | — | — | — | — | (13,550) | — | (13,550) |
| Proceeds from exercise of stock options | 1,801 | — | — | — | 1,801 | — | — | 1,801 |
| Excess tax benefits on exercise of stock options | 3,513 | — | — | — | 3,513 | — | — | 3,513 |
| Taxes paid on vested KGS equity compensation | — | — | — | — | — | (1,144) | | (1,144) |
| Purchase of treasury stock | (4,910) | — | — | — | (4,910) | — | — | (4,910) |
| Net cash flow provided by (used for) financing activities | (523,046) | — | 21,442 | — | (501,604) | 87,184 | 22,276 | (392,144) |
| Effect of exchange rates on cash | — | — | (1,252) | — | (1,252) | — | — | (1,252) |
| Net decrease in cash and equivalents | 54,932 | — | (1,034) | — | 53,898 | (746) | — | 53,152 |
| Cash and equivalents at beginning of period | 5 | — | 1,034 | — | 1,039 | 746 | — | 1,785 |
| Cash and equivalents at end of period | $ 54,937 | $ — | $ — | $ — | $ 54,937 | $ — | $ — | $ 54,937 |

## 20. SEGMENT INFORMATION

We operate in two geographic segments, the U.S. and Canada, where we are engaged in the exploration and production segment of the oil and gas industry. Additionally, we operate a significantly smaller midstream segment in the U.S. and Canada, where we provide natural gas gathering and processing services, primarily to our U.S. and Canadian exploration and production segments. Following the formation of our partnership with KKR, beginning in January 2012, we have additional midstream operations in Canada through Fortune Creek. Revenue earned by KGS prior to the Crestwood Transaction and revenue earned by Fortune Creek for the gathering and processing of our gas has been eliminated on a consolidated basis as is the GPT recognized by our producing properties. Based on the immateriality of our midstream segment, we have combined our U.S. and Canadian midstream information. We evaluate performance based on operating income and property and equipment costs incurred.

| | Exploration & Production | | | | | |
|---|---|---|---|---|---|---|
| | U.S. | Canada | Midstream | Corporate | Elimination | Quicksilver Consolidated |
| | (In thousands) | | | | | |
| **2012** | | | | | | |
| Revenue | $ 598,892 | $ 105,949 | $ 21,735 | $ — | $ (17,538) | $ 709,038 |
| DD&A | 123,370 | 32,686 | 5,182 | 2,386 | — | 163,624 |
| Impairment expense | 2,152,665 | 465,935 | 7,328 | — | — | 2,625,928 |
| Operating income (loss) | (1,921,073) | (474,768) | 8,163 | (78,083) | — | (2,465,761) |
| Property and equipment costs incurred | 189,997 | 174,867 | 18,742 | 6,850 | — | 390,456 |
| **2011** | | | | | | |
| Revenue | $ 806,657 | $ 135,948 | $ 4,573 | $ — | $ (3,555) | $ 943,623 |
| DD&A | 171,438 | 47,116 | 4,889 | 2,320 | — | 225,763 |
| Impairment expense | — | 49,063 | 57,996 | — | — | 107,059 |
| Operating income (loss) | 251,495 | 12,914 | (59,903) | (81,902) | — | 122,604 |
| Property and equipment costs incurred | 487,145 | 131,699 | 64,119 | 11,516 | — | 694,479 |
| **2010** | | | | | | |
| Revenue | $ 788,714 | $ 126,322 | $ 87,426 | $ — | $ (74,131) | $ 928,331 |
| DD&A | 136,361 | 45,335 | 23,523 | 1,984 | — | 207,203 |
| Impairment expense | — | 19,386 | 28,611 | — | — | 47,997 |
| Operating income (loss) | 857,170 | 16,765 | 12,290 | (82,091) | — | 804,134 |
| Property and equipment costs incurred | 452,044 | 123,348 | 154,271 | 5,146 | — | 734,809 |
| **Property, plant and equipment—net** | | | | | | |
| December 31, 2012 | $ 614,071 | $ 294,921 | $ 111,523 | $ 8,543 | $ — | $ 1,029,058 |
| December 31, 2011 | 2,752,101 | 596,935 | 102,237 | 9,246 | — | 3,460,519 |

Total assets by segment can be recalculated from the Condensed Consolidating Balance Sheet included in Note 19. Our Canadian exploration and production assets are represented in the restricted non-guarantor subsidiaries column. Our midstream assets are represented in the total assets of the restricted guarantor subsidiaries and Fortune Creek column. Total assets assigned to the corporate segment are represented above as property, plant and equipment, net while our U.S. exploration and production total assets are the remaining balance.

## 21. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid (received) for interest and income taxes is as follows:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | (In thousands) | | |
| Interest, net of capitalized interest | $ 154,663 | $ 170,814 | $ 136,459 |
| Income taxes | (20,682) | (4,249) | 78,083 |

Other significant non-cash transactions are as follows:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | (In thousands) | | |
| Working capital related to capital expenditures | $ 10,939 | $ 107,586 | $ 100,587 |
| Conveyance of 3,619,901 BBEP common units for producing properties | — | — | 54,407 |
| Quicksilver common shares received for cashless exercise of 34,415 stock options | — | — | 214 |
| Note receivable received for sale of land and building | — | 5,300 | — |

## 22. EMPLOYEE BENEFITS

Quicksilver has a 401(k) retirement plan available to all U.S. full time employees who are at least 21 years of age. We make matching contributions and a fixed annual contribution and have the ability to make discretionary contributions to the plan. Expense associated with company contributions was $2.3 million, $2.3 million and $2.5 million for 2012, 2011 and 2010, respectively.

We have a retirement plan available to all Canadian employees. The plan provides for a match of employees' contributions by us and a fixed annual contribution. Expense associated with company contributions for 2012, 2011 and 2010 was $0.7 million, $0.8 million and $0.8 million, respectively.

We maintain a self-funded health benefit plan that covers all eligible U.S. employees. The plan has been reinsured on an individual claim and total group claim basis. We have an individual stop loss of $125,000 and an aggregating stop loss of $175,000. For 2012, 2011 and 2010 we recognized expense of $5.0 million, $4.8 million and $3.5 million, respectively, for this plan.

## 23. TRANSACTIONS WITH RELATED PARTIES

As of February 28, 2013, members of the Darden family and entities controlled by them beneficially own approximately 30% of our outstanding common stock. Thomas Darden, Glenn Darden and Anne Darden Self are officers and directors of Quicksilver.

We paid $0.1 million in 2012, $0.2 million in 2011, and $0.6 million in 2010 for rent and property management services on buildings owned by entities controlled by members of the Darden family. Rental rates were determined based on comparable rates charged by third parties. In December 2011, we purchased a manufacturing facility from an entity controlled by members of the Darden family for $1.1 million. We previously leased this facility from the seller for the manufacture of oil and gas equipment.

During 2012, 2011 and 2010, we paid $0.5 million, $0.9 million and $0.8 million for use of an airplane owned by an entity controlled by members of the Darden family. Usage rates were determined based upon comparable rates charged by third parties.

Payments received in 2012, 2011 and 2010 from Mercury for sublease rentals, employee insurance coverage and administrative services were $0.1 million, $0.1 million, and $0.3 million, respectively.

An entity controlled by members of the Darden family received $0.2 million in commission for the sale and purchases of property to unrelated third parties in 2011. The entity also received a $1.4 million commission from the lessor in connection with office space leased as of August 2010.

## SUPPLEMENTAL SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table presents selected quarterly financial data derived from our consolidated financial statements. This summary should be read in conjunction with our consolidated financial statements and related notes also contained in this Item 8 to our Annual Report on Form 10-K.

| | Quarter Ended | | | |
|---|---|---|---|---|
| | **March 31** | **June 30** | **September 30** | **December 31** |
| | (In thousands, except per share data) | | | |
| **2012** (1) (2) (3) (4) | (As Restated) | (As Restated) | (As Restated) | |
| Operating revenue | $ 172,866 | $ 194,018 | $ 118,188 | $ 223,966 |
| Operating loss | (267,985) | (1,153,012) | (576,551) | (468,213) |
| Net loss | (211,565) | (802,022) | (790,520) | (548,499) |
| Basic net earnings per share | $ (1.24) | $ (4.72) | $ (4.65) | $ (3.22) |
| Diluted net earnings per share | (1.24) | (4.72) | (4.65) | (3.22) |
| **2011** (5) (6) | | | | |
| Operating revenue | $ 212,187 | $ 248,446 | $ 259,893 | $ 223,097 |
| Operating income (loss) | (793) | 78,676 | 67,981 | (23,260) |
| Net income (loss) | (70,758) | 108,587 | 28,686 | 23,531 |
| Basic net earnings per share | $ (0.42) | $ 0.63 | $ 0.17 | $ 0.14 |
| Diluted net earnings per share | (0.42) | 0.61 | 0.17 | 0.14 |

(1) Operating loss for the first quarter of 2012 includes charges for impairment of $178.0 million and $139.9 million for our U.S. and Canadian oil and gas properties, respectively.

(2) Operating loss for the second quarter of 2012 includes charges for impairment of $1,042.7 million and $157.0 million for our U.S. and Canadian oil and gas properties, respectively.

(3) Operating loss for the third quarter of 2012 includes charges for impairment of $479.9 million and $66.3 million for our U.S. and Canadian oil and gas properties, respectively. Operating loss also includes a $4.9 million impairment charge for other property and equipment in Colorado.

(4) Operating loss for the fourth quarter of 2012 includes charges for impairment of $451.5 million and $102.8 million for our U.S. and Canadian oil and gas properties, respectively. Operating loss also includes a $2.9 million impairment charge related to non-oil and gas properties.

(5) Operating loss for the first quarter of 2011 includes a charge of $49.1 million for impairment of our Canadian oil and gas properties to net realizable value.

(6) Operating loss for fourth quarter 2011 includes gains of $217.9 million from the sale of BBEP Units. Operating income also includes charges for impairment of $58.0 million for our HCDS and certain midstream assets in Texas.

### Restatement of Previously Issued Financial Statements

As part of our year-end 2012 procedures, we concluded that the documentation for our derivatives entered into during 2012 that had fair value on the dates they were initially designated as hedges failed to give consideration to all sources of ineffectiveness. Specifically, our documentation did not include an assessment of whether interest rate changes could cause the instruments to not be effective over the life of the derivative, which was required given the presence of fair value at the date of hedge designation. Management documented its assessment of interest rate risk on similar derivatives in 2011 and concluded its effect to be immaterial and, thus, did not document the risk in 2012. Accordingly, these derivatives did not qualify for hedge accounting in 2012 and their changes in value must be recognized in earnings.

Because the derivatives did not qualify for hedge accounting, their inclusion in the U.S. and Canadian full cost ceiling was inappropriate. Thus, our full cost ceiling calculations were revised and resulted in restatements to increase impairment expense recognized in earlier quarters. Also, we determined that the deferred taxes used in our Canadian ceiling test for the first two quarters of 2012 included temporary differences for non-property related items. We have restated the ceiling impairments from the interim quarters to correct for these inclusions. The impairment expense that resulted from the ceiling calculation restatements also caused reductions to our depletion rates for the second and third quarters and we have restated depletion expense. Income taxes have also been restated for each of the first two quarters of 2012 to reflect the foregoing restated items.

The following financial statements summarize the impact to the previously issued statements.

**QUICKSILVER RESOURCES INC.**
**CONDENSED CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)**
**In thousands, except for per share data – Unaudited**

| | For the Three Months Ended March 31, 2012 | | For the Three Months Ended June 30, 2012 | | For the Three Months Ended September 30, 2012 | |
|---|---|---|---|---|---|---|
| | As previously reported | As restated | As previously reported | As restated | As previously reported | As restated |
| Revenue | | | | | | |
| Production | 171,820 | 166,454 | 150,503 | 150,311 | 157,699 | 156,288 |
| Sales of purchased natural gas | 12,086 | 12,086 | 9,442 | 9,442 | 21,313 | 21,313 |
| Derivative gains (losses), net | — | (6,664) | — | 33,139 | — | (60,377) |
| Other | (38,437) | 990 | 8,617 | 1,126 | (1,310) | 964 |
| Total revenue | 145,469 | 172,866 | 168,562 | 194,018 | 177,702 | 118,188 |
| Operating expense | | | | | | |
| Lease operating | 28,691 | 28,691 | 21,599 | 21,599 | 22,115 | 22,115 |
| Gathering, processing and transportation | 43,077 | 43,077 | 42,624 | 42,624 | 41,338 | 41,338 |
| Production and ad valorem taxes | 6,763 | 6,763 | 7,189 | 7,189 | 6,881 | 6,881 |
| Costs of purchased natural gas | 11,937 | 11,937 | 9,337 | 9,337 | 21,254 | 21,254 |
| Depletion, depreciation and accretion | 54,439 | 54,439 | 51,942 | 48,016 | 43,209 | 34,014 |
| Impairment | 62,746 | 317,928 | 991,921 | 1,199,726 | 546,835 | 551,132 |
| General and administrative | 19,095 | 19,095 | 18,405 | 18,405 | 17,335 | 17,335 |
| Other operating | 18 | 18 | 134 | 134 | 670 | 670 |
| Total expense | 226,766 | 481,948 | 1,143,151 | 1,347,030 | 699,637 | 694,739 |
| Crestwood earn-out | 41,097 | 41,097 | — | — | — | — |
| Operating income (loss) | (40,200) | (267,985) | (974,589) | (1,153,012) | (521,935) | (576,551) |
| Income (loss) from earnings of BBEP | | | | | | |
| Other income - net | 93 | 93 | 65 | 65 | (395) | (395) |
| Fortune Creek accretion | (4,741) | (4,741) | (4,830) | (4,830) | (4,978) | (4,978) |
| Interest expense | (40,170) | (40,170) | (40,076) | (40,076) | (42,102) | (42,102) |
| Income (loss) before income taxes | (85,018) | (312,803) | (1,019,430) | (1,197,853) | (569,410) | (624,026) |
| Income tax (expense) benefit | 25,094 | 101,238 | 346,889 | 395,831 | (82,352) | (166,494) |
| Net income (loss) | (59,924) | (211,565) | (672,541) | (802,022) | (651,762) | (790,520) |
| Reclassification adjustments related to settlements of derivative contracts - net of income tax | (32,534) | (28,589) | (37,133) | (36,992) | (35,182) | (34,145) |
| Net change in derivative fair value - net of income tax | 91,789 | 61,287 | 20,219 | 10,923 | (51,057) | (11,905) |
| Foreign currency translation adjustment | 7,928 | 1,451 | (8,598) | (6,381) | 4,901 | (565) |
| Other comprehensive income (loss) | 67,183 | 34,149 | (25,512) | (32,450) | (81,338) | (46,615) |
| Comprehensive income (loss) | 7,259 | (177,416) | (698,053) | (834,472) | (733,100) | (837,135) |
| Earnings (loss) per common share - basic | (0.35) | (1.24) | (3.96) | (4.72) | (3.83) | (4.65) |
| Earnings (loss) per common share - diluted | (0.35) | (1.24) | (3.96) | (4.72) | (3.83) | (4.65) |

# QUICKSILVER RESOURCES INC.
# CONDENSED CONSOLIDATED BALANCE SHEETS
## In thousands – Unaudited

| | As of March 31, 2012 | | As of June 30, 2012 | | As of September 30, 2012 | |
|---|---|---|---|---|---|---|
| | As previously reported | As restated | As previously reported | As restated | As previously reported | As restated |
| ASSETS | | | | | | |
| Current assets | | | | | | |
| Cash | 13,032 | 13,032 | 14,003 | 14,003 | 7,436 | 7,436 |
| Accounts receivable - net of allowance for doubtful accounts | 62,686 | 62,686 | 64,667 | 64,667 | 67,951 | 67,951 |
| Derivative assets at fair value | 227,591 | 227,591 | 189,536 | 189,536 | 126,075 | 126,075 |
| Other current assets | 29,790 | 29,790 | 36,690 | 36,690 | 41,575 | 41,575 |
| Total current assets | 333,099 | 333,099 | 304,896 | 304,896 | 243,037 | 243,037 |
| Property, plant and equipment - net | | | | | | |
| Oil and gas properties, full cost method | 3,258,975 | 2,997,316 | 2,346,209 | 1,883,627 | 1,846,028 | 1,381,055 |
| Other property and equipment | 240,703 | 240,703 | 249,857 | 249,857 | 248,021 | 248,021 |
| Property, plant and equipment - net | 3,499,678 | 3,238,019 | 2,596,066 | 2,133,484 | 2,094,049 | 1,629,076 |
| Derivative assets at fair value | 170,274 | 170,274 | 159,189 | 159,189 | 109,313 | 109,313 |
| Deferred income taxes | — | — | 134,190 | 239,467 | — | 38,326 |
| Other assets | 51,680 | 51,680 | 50,183 | 50,183 | 43,845 | 43,845 |
| | 4,054,731 | 3,793,072 | 3,244,524 | 2,887,219 | 2,490,244 | 2,063,597 |
| LIABILITIES AND EQUITY | | | | | | |
| Current liabilities | | | | | | |
| Accounts payable | 88,750 | 88,750 | 111,941 | 111,941 | 48,143 | 48,143 |
| Accrued liabilities | 106,885 | 106,885 | 139,257 | 139,257 | 123,661 | 123,661 |
| Current deferred tax liability | 63,636 | 63,636 | 45,968 | 45,968 | 3,243 | 3,243 |
| Total current liabilities | 259,271 | 259,271 | 297,166 | 297,166 | 175,047 | 175,047 |
| Long-term debt | 2,012,936 | 2,012,936 | 2,069,726 | 2,069,726 | 2,165,384 | 2,165,384 |
| Partnership liability | 130,071 | 130,071 | 130,357 | 130,357 | 135,446 | 135,446 |
| Asset retirement obligations | 93,945 | 93,945 | 94,872 | 94,872 | 97,771 | 97,771 |
| Derivative liabilities at fair value | 24,398 | 24,398 | 6,538 | 6,538 | 42,538 | 42,538 |
| Other liabilities | 28,461 | 28,461 | 28,461 | 28,461 | 19,242 | 19,242 |
| Deferred income taxes | 233,172 | 156,187 | 38,611 | 2,399 | 1,518 | — |
| Commitments and contingencies | | | | | | |
| Stockholders' equity | | | | | | |
| Preferred stock | — | — | — | — | — | — |
| Common stock | 1,790 | 1,790 | 1,788 | 1,788 | 1,788 | 1,788 |
| Paid in capital in excess of par value | 742,635 | 742,635 | 747,029 | 747,029 | 755,080 | 755,080 |
| Treasury stock | (48,692) | (48,692) | (48,715) | (48,715) | (49,161) | (49,161) |
| Accumulated other comprehensive income | 282,041 | 249,007 | 256,529 | 216,557 | 175,191 | 169,942 |
| Retained earnings (deficit) | 294,703 | 143,063 | (377,838) | (658,959) | (1,029,600) | (1,449,480) |
| Total stockholders' equity | 1,272,477 | 1,087,803 | 578,793 | 257,700 | (146,702) | (571,831) |
| | 4,054,731 | 3,793,072 | 3,244,524 | 2,887,219 | 2,490,244 | 2,063,597 |

## QUICKSILVER RESOURCES INC.
## CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
### In thousands – Unaudited

| | For the Three Months Ended March 31, 2012 | | For the Six Months Ended June 30, 2012 | | For the Nine Months Ended September 30, 2012 | |
|---|---|---|---|---|---|---|
| | As previously reported | As restated | As previously reported | As restated | As previously reported | As restated |
| Operating activities: | | | | | | |
| Net loss | (59,924) | (211,565) | (732,465) | (1,013,587) | (1,384,227) | (1,804,107) |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | | | | | |
| Depletion, depreciation and accretion | 54,439 | 54,439 | 106,381 | 102,454 | 149,590 | 136,469 |
| Impairment expense | 62,746 | 317,928 | 1,054,668 | 1,517,655 | 1,601,502 | 2,068,787 |
| Crestwood earn-out | (41,097) | (41,097) | (41,097) | (41,097) | (41,097) | (41,097) |
| Deferred income tax expense (benefit) | (25,443) | (101,586) | (372,741) | (497,827) | (285,204) | (326,149) |
| Non-cash (gain) loss from hedging and derivative activities | 45,649 | 18,251 | 61,503 | 8,651 | 82,252 | 88,913 |
| Stock-based compensation | 5,630 | 5,630 | 10,021 | 10,021 | 16,983 | 16,983 |
| Non-cash interest expense | 1,742 | 1,742 | 3,469 | 3,469 | 8,060 | 8,060 |
| Fortune Creek accretion | 4,741 | 4,741 | 9,571 | 9,571 | 14,549 | 14,549 |
| Other | (29) | (29) | 328 | 328 | 495 | 495 |
| Changes in assets and liabilities | | | | | | |
| Accounts receivable | 32,612 | 32,612 | 30,600 | 30,600 | 27,259 | 27,259 |
| Prepaid expenses and other assets | (1,874) | (1,874) | (5,031) | (5,031) | (4,503) | (4,503) |
| Accounts payable | (16,319) | (16,319) | (21,838) | (21,838) | (24,329) | (24,329) |
| Accrued and other liabilities | (35,503) | (35,503) | (3,853) | (3,853) | (19,954) | (19,954) |
| Net cash provided by operating activities | 27,370 | 27,370 | 99,516 | 99,516 | 141,376 | 141,376 |
| Investing activities: | | | | | | |
| Capital expenditures | (174,922) | (174,922) | (307,169) | (307,169) | (437,172) | (437,172) |
| Proceeds from Crestwood earn-out | 41,097 | 41,097 | 41,097 | 41,097 | 41,097 | 41,097 |
| Proceeds from sale of properties and equipment | 460 | 460 | 3,372 | 3,372 | 3,843 | 3,843 |
| Net cash provided (used) by investing activities | (133,365) | (133,365) | (262,700) | (262,700) | (392,232) | (392,232) |
| Financing activities: | | | | | | |
| Issuance of debt | 161,658 | 161,658 | 255,775 | 255,775 | 367,646 | 367,646 |
| Repayments of debt | (53,115) | (53,115) | (88,115) | (88,115) | (111,115) | (111,115) |
| Debt issuance costs paid | (191) | (191) | (148) | (148) | (3,048) | (3,048) |
| Distribution of Fortune Creek Partnership funds | — | — | (1,845) | (1,845) | (6,520) | (6,520) |
| Proceeds from exercise of stock options | 10 | 10 | 11 | 11 | 11 | 11 |
| Excess tax benefits on stock compensation | — | — | — | — | 1,089 | 1,089 |
| Purchase of treasury stock | (2,341) | (2,341) | (2,364) | (2,364) | (2,810) | (2,810) |
| Net cash provided (used) by financing activities | 106,021 | 106,021 | 163,314 | 163,314 | 245,253 | 245,253 |
| Effect of exchange rate changes in cash | (140) | (140) | 727 | 727 | (107) | (107) |
| Net change in cash | (114) | (114) | 857 | 857 | (5,710) | (5,710) |
| Cash and cash equivalents at beginning of period | 13,146 | 13,146 | 13,146 | 13,146 | 13,146 | 13,146 |
| Cash and cash equivalents at end of period | 13,032 | 13,032 | 14,003 | 14,003 | 7,436 | 7,436 |

*Quarter Ended March 31, 2012*

The derivative restatement adjustment decreased production revenue by $3.6 million and $1.8 million for the U.S. and Canada, respectively, while derivative gains increased $20.7 million and $12.0 million for the U.S. and Canada, respectively. Impairment expense increased as the result of these derivatives no longer being included in the cost center ceiling by $115.7 million and $139.5 million for the U.S. and Canada, respectively. The income tax impact of these adjustments resulted in an increase to the tax benefit of $41.9 million and $34.2 million for the U.S. and Canada, respectively. Our consolidated net loss increased $151.6 million. Other comprehensive income decreased $33.0 million as a result of these adjustments. The restatement increased diluted net loss per share by $0.89, from diluted net loss per share of$0.35 as previously reported, to diluted net loss per share of $1.24.

*Quarter Ended June 30, 2012*

The derivative restatement adjustment increased production revenue by $1.3 million for the U.S. and decreased production revenue by $1.5 million for Canada while derivative gains increased$22.2 million and $3.5 million for the U.S. and Canada, respectively. Impairment expense increased as the result of these derivatives no longer being included in the cost center ceiling by $144.0 million and $63.8 million for the U.S. and Canada, respectively, while depletion expense decreased $1.3 million and $2.6 million for the U.S. and Canada, respectively. The income tax impact of these adjustments resulted in an increase to the tax benefit of $34.3 million and $14.6 million for the U.S. and Canada, respectively. Our consolidated net loss increased $129.5 million. Other comprehensive income decreased $6.9 million as a result of these adjustments. The restatement increased diluted net loss per share by $0.76, from diluted net loss per share of $3.96 as previously reported, to diluted net loss per share of $4.72.

*Quarter Ended September 30, 2012*

The derivative restatement adjustment decreased production revenue by $0.3 million and $1.1 million for the U.S. and Canada, respectively, while derivative losses increased $42.8 million and $15.3 million for the U.S. and Canada, respectively. Impairment expense increased as the result of these derivatives no longer being included in the cost center ceiling by $43.4 million for the U.S. but decreased impairment expense by $39.1 million for Canada, while depletion expense decreased $3.3 million and $5.9 million for the U.S. and Canada, respectively. The income tax impact of these adjustments resulted in an increase to the tax expense of $75.3 million and $8.8 million for the U.S. and Canada, respectively. Our consolidated net loss increased $138.8 million. Other comprehensive income increased $34.7 million as a result of these adjustments. The restatement increased diluted net loss per share by $0.82, from diluted net loss per share of $3.83 as previously reported, to diluted net loss per share of $4.65.

## SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Proved oil and gas reserves estimates for our properties in the U.S. and Canada were prepared by independent petroleum engineers from Schlumberger Technology Corporation and LaRoche Petroleum Consultants, Ltd., respectively. The reserve reports were prepared in accordance with guidelines established by the SEC. Natural gas, NGL and oil prices used in the 2012, 2011 and 2010 reserve reports are the unweighted average of the preceding 12-month first-day-of-the-month prices as of the date of the reserve reports. For all years, operating costs, production and ad valorem taxes and future development costs were based on year-end costs with no escalation.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. The following reserve data represent estimates only and should not be construed as being exact. Moreover, the present values should not be construed as the current market value of our natural gas, NGL and oil reserves or the costs that would be incurred to obtain equivalent reserves.

As required by GAAP, we have also included separate disclosure and presentation of our share of BBEP's proved reserves for 2010 because we accounted for BBEP by the equity method.

### Consolidated Quicksilver (Excluding BBEP Reserves)

The changes in our proved reserves for the three years ended December 31, 2012 were as follows:

| | Natural Gas (MMcf) | | | NGL (MBbl) | | | Oil (MBbl) | | |
|---|---|---|---|---|---|---|---|---|---|
| | U.S. | Canada | Total | U.S. | Canada | Total | U.S. | Canada | Total |
| **December 31, 2009** | 1,556,034 | 253,053 | 1,809,087 | 98,261 | 13 | 98,274 | 2,859 | — | 2,859 |
| Revisions [4] | 13,389 | (1,224) | 12,165 | 4,845 | 2 | 4,847 | 606 | — | 606 |
| Extensions and discoveries [3] | 323,713 | 17,309 | 341,022 | 13,695 | — | 13,695 | 146 | — | 146 |
| Purchases in place [1] | 124,996 | 22,005 | 147,001 | — | — | — | — | — | — |
| Production | (76,409) | (25,255) | (101,664) | (4,357) | (3) | (4,360) | (303) | — | (303) |
| **December 31, 2010** | 1,941,723 | 265,888 | 2,207,611 | 112,444 | 12 | 112,456 | 3,308 | — | 3,308 |
| Revisions [4] | (172,643) | 15,066 | (157,577) | (8,519) | 1 | (8,518) | (43) | — | (43) |
| Extensions and discoveries [3] | 155,662 | 76,067 | 231,729 | 2,652 | — | 2,652 | 43 | — | 43 |
| Production | (95,838) | (26,390) | (122,228) | (4,432) | (2) | (4,434) | (273) | — | (273) |
| **December 31, 2011** | 1,828,904 | 330,631 | 2,159,535 | 102,145 | 11 | 102,156 | 3,035 | — | 3,035 |
| Revisions [4] | (910,386) | (33,945) | (944,331) | (45,379) | 1 | (45,378) | (479) | — | (479) |
| Extensions and discoveries [3] | 25,858 | 9 | 25,867 | 3,518 | — | 3,518 | 345 | — | 345 |
| Sales in place [2] | (20,616) | — | (20,616) | (42) | — | (42) | (85) | — | (85) |
| Production | (75,712) | (29,912) | (105,624) | (4,069) | (2) | (4,071) | (287) | — | (287) |
| **December 31, 2012** | 848,048 | 266,783 | 1,114,831 | 56,173 | 10 | 56,183 | 2,529 | — | 2,529 |
| **Proved developed reserves** | | | | | | | | | |
| December 31, 2010 | 1,312,777 | 242,941 | 1,555,718 | 64,908 | 12 | 64,920 | 2,775 | — | 2,775 |
| December 31, 2011 | 1,244,187 | 299,371 | 1,543,558 | 60,902 | 11 | 60,913 | 2,545 | — | 2,545 |
| December 31, 2012 | 725,361 | 266,783 | 992,144 | 47,284 | 10 | 47,294 | 2,416 | — | 2,416 |
| **Proved undeveloped reserves** | | | | | | | | | |
| December 31, 2010 | 628,946 | 22,947 | 651,893 | 47,536 | — | 47,536 | 533 | — | 533 |
| December 31, 2011 | 584,717 | 31,260 | 615,977 | 41,243 | — | 41,243 | 490 | — | 490 |
| December 31, 2012 | 122,687 | — | 122,687 | 8,890 | — | 8,890 | 113 | — | 113 |

(1) Purchases of U.S. reserves in place during 2010 relate principally to the acquisition of additional working interest in our company-operated Lake Arlington Asset and the Alliance Transaction. These transactions are more fully described in Note 3 to our consolidated financial statements. The 2010 purchase of Canadian reserves in place relates to the acquisition of additional working interests in a company-operated field located in our Horseshoe Canyon Asset.

(2) Sales of reserves in place during 2012 relate to our agreement to allow an outside working interest owner to fund the completion costs for twelve wells in our Barnett Shale Asset for which they received a preferential right to reserves. It also includes a minimal sale of reserves in our Niobrara Asset to SWEPI.

(3) Extensions and discoveries for each period presented represent extensions to reserves attributable to additional drilling activity subsequent to discovery. U.S. extensions and discoveries for:
- 2012 are 96% attributable to our Barnett Shale Asset, 4% to our Niobrara and West Texas Assets (of which 13% were proved developed) ;
- 2011 are 100% attributable to our Barnett Shale Asset (of which 11% were proved developed); and
- 2010 are 100% attributable to our Barnett Shale Asset (of which 40% were proved developed).

Canadian extensions and discoveries for:
- 2012 are attributable to our Horseshoe Canyon Asset;
- 2011 are 97% attributable to our Horn River Asset and 3% are attributable to our Horseshoe Canyon Asset; and
- 2010 are 69% attributable to our Horn River Asset and 31% are attributable to our Horseshoe Canyon Asset.

(4) Revisions for each period presented reflect upward (downward) changes in previous estimates attributable to changes in economic factors of (590,064) MMcfe, (54,539) MMcfe and 117,975 MMcfe in 2012, 2011 and 2010, respectively, and changes in non-economic factors of (629,407) MMcfe, (154,405) MMcfe and (73,096) MMcfe in 2012, 2011 and 2010, respectively, including:
- Removal of proved undeveloped reserves that had not been developed within five years: (250) Bcfe and (55) Bcfe in 2012 and 2011, respectively;
- changes in performance related to offsetting activities, higher pipeline pressures and other factors: (291) Bcfe and (99) Bcfe in 2012 and 2011, respectively and
- revision of type curve of non producing wells based on comparison to producing analogs: (88) Bcfe in 2012.

The carrying value of our oil and gas assets as of December 31, 2012, 2011 and 2010 were as follows:

| | U.S. | Canada | Consolidated |
|---|---|---|---|
| | | (In thousands) | |
| **2012** | | | |
| Proved properties | $ 4,681,860 | $ 1,089,053 | $ 5,770,913 |
| Unevaluated properties | 90,035 | 217,232 | 307,267 |
| Accumulated DD&A | (4,233,391) | (1,063,829) | (5,297,220) |
| Net capitalized costs | $ 538,504 | $ 242,456 | $ 780,960 |
| **2011** | | | |
| Proved properties | $ 4,380,745 | $ 928,585 | $ 5,309,330 |
| Unevaluated properties | 252,737 | 180,604 | 433,341 |
| Accumulated DD&A | (1,965,258) | (550,937) | (2,516,195) |
| Net capitalized costs | $ 2,668,224 | $ 558,252 | $ 3,226,476 |
| **2010** | | | |
| Proved properties | $ 3,965,585 | $ 839,576 | $ 4,805,161 |
| Unevaluated properties | 153,880 | 160,663 | 314,543 |
| Accumulated DD&A | (1,800,764) | (478,621) | (2,279,385) |
| Net capitalized costs | $ 2,318,701 | $ 521,618 | $ 2,840,319 |

Our consolidated capital costs incurred for acquisition, exploration and development activities during each of the three years in the period ended December 31, 2012, were as follows:

| | U.S. | Canada | Consolidated |
|---|---|---|---|
| | | (In thousands) | |
| **2012** | | | |
| Proved acreage | $ — | $ — | $ — |
| Unproved acreage | 23,711 | 5,612 | 29,323 |
| Development costs | 131,926 | 178,808 | 310,734 |
| Exploration costs | 35,244 | 8,304 | 43,548 |
| Total | $ 190,881 | $ 192,724 | $ 383,605 |
| **2011** | | | |
| Proved acreage | $ — | $ — | $ — |
| Unproved acreage | 145,099 | — | 145,099 |
| Development costs | 304,373 | 90,361 | 394,734 |
| Exploration costs | 37,673 | 41,338 | 79,011 |
| Total | $ 487,145 | $ 131,699 | $ 618,844 |
| **2010** | | | |
| Proved acreage | $ 125,647 | $ 19,271 | $ 144,918 |
| Unproved acreage | 44,271 | 827 | 45,098 |
| Development costs | 378,056 | 14,182 | 392,238 |
| Exploration costs | 9,385 | 57,896 | 67,281 |
| Total | $ 557,359 | $ 92,176 | $ 649,535 |

Consolidated results of operations from our producing activities for each of the three years ended December 31, 2012, are set forth below:

| | U.S. | Canada | Consolidated |
|---|---|---|---|
| | | (In thousands) | |
| **2012** | | | |
| Natural gas, NGL and oil revenue | $ 538,902 | $ 92,045 | $ 630,947 |
| Operating expense | 226,542 | 60,501 | 287,043 |
| Depletion expense | 116,005 | 24,897 | 140,902 |
| Impairment expense | 2,152,128 | 465,935 | 2,618,063 |
| | (1,955,773) | (459,288) | (2,415,061) |
| Income tax expense (benefit) | (684,521) | (114,822) | (799,343) |
| Results from producing activities | $ (1,271,252) | $ (344,466) | $ (1,615,718) |
| **2011** | | | |
| Natural gas, NGL and oil revenue | $ 673,041 | $ 127,502 | $ 800,543 |
| Operating expense | 267,890 | 54,770 | 322,660 |
| Depletion expense | 164,493 | 38,228 | 202,721 |
| Impairment expense | — | 49,063 | 49,063 |
| | 240,658 | (14,559) | 226,099 |
| Income tax expense (benefit) | 84,230 | (4,222) | 80,008 |
| Results from producing activities | $ 156,428 | $ (10,337) | $ 146,091 |
| **2010** | | | |
| Natural gas, NGL and oil revenue | $ 732,456 | $ 123,893 | $ 856,349 |
| Operating expense | 168,164 | 44,836 | 213,000 |
| Depletion expense | 129,843 | 38,825 | 168,668 |
| Impairment expense | — | 19,386 | 19,386 |
| | 434,449 | 20,846 | 455,295 |
| Income tax expense | 152,057 | 6,045 | 158,102 |
| Results from producing activities | $ 282,392 | $ 14,801 | $ 297,193 |

The Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves ("Standardized Measure") does not purport to present the fair market value of our natural gas and oil properties. An estimate of such value should consider, among other factors, anticipated future prices of natural gas and oil, the probability of recoveries in excess of existing proved reserves, the value of probable reserves and acreage prospects, estimated future capital and operating costs and perhaps different discount rates. It should be noted that estimates of reserve quantities, especially from new discoveries, are inherently imprecise and subject to substantial revision.

Under the Standardized Measure, future cash inflows for 2012 were estimated by applying the unweighted average of the preceding 12-month first-day-of-the-month prices, adjusted for contracts with price floors but excluding hedges, and unescalated year-end costs to the estimated future production of the year-end reserves. These prices have varied widely and have a significant impact on both the quantities and value of the proved reserves as reduced prices cause wells to reach the end of their economic life much sooner and also make certain proved undeveloped locations uneconomical, both of which reduce reserves. The following representative prices were used in the Standardized Measure and were adjusted by field for appropriate regional differentials:

| | At December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| Natural gas – Henry Hub, per MMBtu | $ 2.76 | $ 4.12 | $ 4.38 |
| Natural gas – AECO, per MMBtu | 2.35 | 3.65 | 4.08 |
| Oil – WTI Cushing, per Bbl | 94.71 | 95.71 | 79.43 |

The reference price used for our NGLs was based on WTI Cushing, adjusted for local differentials, gravity and BTU.

Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the associated proved natural gas and oil properties. Tax credits and net operating loss carry-forwards were also considered in the future income tax calculation. Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure.

The Standardized Measure at December 31, 2012, 2011 and 2010 was as follows:

| | U.S. | Canada | Total |
|---|---|---|---|
| | | (In thousands) | |
| **December 31, 2012** | | | |
| Future revenue | $ 3,980,643 | $ 472,539 | $ 4,453,182 |
| Future production costs | (2,552,863) | (324,424) | (2,877,287) |
| Future development costs | (239,532) | (56,354) | (295,886) |
| Future income taxes | 81,847 | 80,206 | 162,053 |
| Future net cash flows | 1,270,095 | 171,967 | 1,442,062 |
| 10% discount | (667,738) | (59,204) | (726,942) |
| Standardized measure of discounted future cash flows relating to proved reserves | $ 602,357 | $ 112,763 | $ 715,120 |
| **December 31, 2011** | | | |
| Future revenue | $ 11,647,002 | $ 1,055,711 | $ 12,702,713 |
| Future production costs | (5,496,246) | (463,852) | (5,960,098) |
| Future development costs | (1,125,641) | (146,658) | (1,272,299) |
| Future income taxes | (1,229,968) | (44,183) | (1,274,151) |
| Future net cash flows | 3,795,147 | 401,018 | 4,196,165 |
| 10% discount | (2,286,449) | (174,863) | (2,461,312) |
| Standardized measure of discounted future cash flows relating to proved reserves | $ 1,508,698 | $ 226,155 | $ 1,734,853 |
| **December 31, 2010** | | | |
| Future revenue | $ 12,057,094 | $ 1,047,106 | $ 13,104,200 |
| Future production costs | (5,636,375) | (458,187) | (6,094,562) |
| Future development costs | (1,253,546) | (93,668) | (1,347,214) |
| Future income taxes | (1,254,255) | (62,370) | (1,316,625) |
| Future net cash flows | 3,912,918 | 432,881 | 4,345,799 |
| 10% discount | (2,377,166) | (182,255) | (2,559,421) |
| Standardized measure of discounted future cash flows relating to proved reserves | $ 1,535,752 | $ 250,626 | $ 1,786,378 |

The primary changes in the Standardized Measure for 2012, 2011 and 2010 were as follows:

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| | | (In thousands) | |
| Sales of oil and gas net of production costs | $ (149,326) | $ (477,883) | $ (643,349) |
| Net changes in economic factors | (1,362,793) | 32,175 | 1,080,136 |
| Extensions and discoveries | 27,003 | 251,635 | 274,255 |
| Development costs incurred | 172,563 | 233,294 | 208,613 |
| Changes in estimated future development costs | 620,127 | (60,642) | (341,612) |
| Purchase and sale of reserves, net | (20,529) | — | 103,865 |
| Revision of estimates | (1,219,609) | (224,784) | 182,772 |
| Accretion of discount | 196,315 | 197,902 | 124,644 |
| Net change in income taxes | 560,485 | 1,404 | (392,275) |
| Change in timing and other differences | 156,031 | (4,626) | 6,650 |
| Net increase (decrease) | $ (1,019,733) | $ (51,525) | $ 603,699 |

**Quicksilver's Share of BBEP Reserves**

The following disclosures required under GAAP represent our share of BBEP's reserves and BBEP's oil and gas operations as of December 31, 2010, which are all located in the U.S. In 2011, we disposed of our entire investment in BBEP. Note 7 in our consolidated financial statements contains additional information regarding our relationship with BBEP.

The following provides information regarding ownership percentages applied to BBEP's gross reported amounts, as applicable:

| | 2010 |
|---|---|
| Ownership in BBEP at December 31, | 29.44% |
| Annualized weighted average ownership of BBEP | 34.62% |

The changes in our share of BBEP's oil and gas reserves were as follows:

| | For the Year Ended December 31, 2010 | | |
|---|---|---|---|
| | Total (Mboe) | Gas (MMcf) | Oil (MBbl) |
| Beginning balance | 45,027 | 175,869 | 15,715 |
| Revision of previous estimates | 4,438 | 14,371 | 2,043 |
| Purchase of reserves in place [(1)] | 515 | 2,943 | 24 |
| Sale of reserves in place [(1)] | (12,652) | (49,363) | (4,424) |
| Production | (2,319) | (7,357) | (1,093) |
| Ending balance | 35,009 | 136,463 | 12,265 |
| Proved developed reserves [(2)] | | | |
| Beginning balance | 40,847 | 161,491 | 13,931 |
| Ending balance | 31,881 | 122,887 | 11,399 |
| Proved undeveloped reserves [(2) (3)] | | | |
| Beginning balance | 4,180 | 14,378 | 1,784 |
| Ending balance | 3,128 | 13,576 | 866 |

(1) Amounts are included as needed to reconcile Quicksilver's portion of beginning reserves to ending reserves that result from changes in Quicksilver's proportionate ownership of BBEP.

(2) During 2010, capital expenditures of $11.3 million were incurred and 16 wells drilled to convert 922 MMcf of natural gas and 959 MBbl of oil from proved undeveloped to proved developed.

(3) As of December 31, 2010, no material proved undeveloped reserves have remained undeveloped for more than five years.

The following representative prices were used in BBEP's Standardized Measure:

| | | Year Ended December 31, 2010 |
|---|---|---|
| Representative prices: | | |
| Natural Gas-Henry Hub | $ | 4.38 |
| Oil-WTI Cushing | | 79.40 |

The following table summarizes our share of the capital costs incurred by BBEP during the year ended December 31, 2010:

| | | 2010 |
|---|---|---|
| | | (In thousands) |
| Proved properties | $ | 580 |
| Unproved properties | | 996 |
| Development costs | | 22,487 |
| Asset retirement costs | | 3,349 |
| Total | $ | 27,412 |

The following table summarizes our share of BBEP's results of operations from its producing activities for the year ended December 31, 2010:

| | | 2010 |
|---|---|---|
| | | (In thousands) |
| Oil, natural gas and NGL sales | $ | 110,003 |
| Gain (loss) on commodity derivative instruments | | 12,156 |
| Operating costs | | (49,343) |
| Depreciation, depletion & amortization | | (34,684) |
| Income tax benefit | | 71 |
| Results from producing activities | $ | 38,203 |

The following table summarizes our share of BBEP's Standardized Measure at December 31, 2010:

| | | 2010 |
|---|---|---|
| | | (In thousands) |
| Future revenues | $ | 1,500,867 |
| Future development costs | | (73,954) |
| Future production costs | | (770,940) |
| Future net cash flows | | 655,973 |
| 10% discount | | (342,435) |
| Standardized measure of discounted future cash flows relating to proved reserves | $ | 313,538 |

The following table summarizes our share of the primary changes in BBEP's Standardized Measure for 2010:

| | At December 31, 2010 | |
|---|---|---|
| | (In thousands) | |
| Beginning balance | $ | 307,303 |
| Sales, net of production costs | | (51,587) |
| Net changes in sales and transfer prices, net of production expense | | 90,185 |
| Previously estimated development costs incurred | | 14,053 |
| Changes in estimated future development costs | | (30,975) |
| Purchase of reserves in place [(1)] | | 493 |
| Sale of reserves in place [(1)] | | (83,651) |
| Revision of quantity estimates and timing of production | | 45,353 |
| Accretion of discount | | 22,365 |
| Ending balance | $ | 313,539 |

(1) Amounts are included as needed to reconcile our portion of beginning value to ending value that result from changes in our proportionate ownership of BBEP.

## ITEM 9. Changes in and Disagreements with Accountants or Accounting and Financial Disclosure

None.

## ITEM 9A. Controls and Procedures

### Disclosure Controls and Procedures

Disclosure controls and procedures, as defined in SEC literature, are controls and other procedures that are designed to ensure that the information that we are required to disclose in the reports that we file or submit to the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

In connection with the preparation of this Annual Report on Form 10-K, our management, under the supervision and with the participation of our Chief Executive Officer and our Chief Financial Officer, carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2012. In making this this evaluation, our management considered the matters relating to the material weaknesses discussed below.

Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were not effective at the reasonable assurance level as of December 31, 2012. In light of the material weakness related to derivatives described below, we have restated our 2012 quarterly financial statements because we determined certain derivatives designated as hedges, which had fair values at their designation date did not qualify for hedge accounting as originally presented. Further, as described below, we had a material weakness related to deferred income taxes. We have concluded that the financial statements in this Annual Report on Form 10-K present fairly, in all material respects, our consolidated financial position, results of operations and cash flows in conformity with generally accepted accounting principles.

### Management's Report on Internal Control Over Financial Reporting

Our management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rules 13a-15(f) under the Exchange Act. Because of its inherent limitations, internal control over financial reporting may not prevent or detect all 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 existing policies or procedures may deteriorate.

Under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, our management conducted an assessment of our internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control — Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on this assessment, our management has concluded that, as of December 31, 2012, it did not maintain effective internal control over financial reporting due to two material weaknesses in the operating effectiveness of our controls. Our controls failed to detect that, for contracts designated as hedges that had a fair value on the date of designation, there were undocumented potential sources of ineffectiveness. Specifically, our documentation in 2012 did not include an assessment of whether interest rate changes could cause the instruments to not be effective over the life of the derivative, which was required due to the presence of fair value on the designation date. We also had a material weakness related to the operating effectiveness of controls over the reconciliation of deferred income taxes, particularly related to the tax basis in property, plant and equipment.

The effectiveness of our internal control over financial reporting as of December 31, 2012, has been audited by Ernst & Young LLP, our independent registered public accounting firm, and they have issued an attestation report on our internal control over financial reporting which is included herein.

**Changes in Internal Control Over Financial Reporting**

There has been no change in our internal control over financial reporting during the quarter ended December 31, 2012, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Quicksilver Resources Inc.

We have audited Quicksilver Resources Inc.'s 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 (the COSO criteria). Quicksilver Resources Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. The following material weaknesses have been identified and included in management's assessment. Management has identified a material weakness at December 31, 2012 in the operating effectiveness of controls related to Quicksilver Resources Inc.'s documentation over derivative financial instruments in 2012 that had fair values at the date management designated the derivatives as a hedge. Further, management has identified a material weakness at December 31, 2012 in the operating effectiveness of controls related to the reconciliation of deferred income taxes, particularly related to the tax basis in property, plant and equipment. We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Quicksilver Resources Inc. as of December 31, 2012, and the related consolidated statement of income (loss) and comprehensive income (loss), equity, and cash flows for the year ended December 31, 2012. These material weaknesses were considered in determining the nature, timing and extent of audit tests applied in our audit of the 2012 financial statements, and this report does not affect our report dated March 22, 2013, which expressed an unqualified opinion on those financial statements.

In our opinion, because of the effect of the material weaknesses described above on the achievement of the objectives of the control criteria, Quicksilver Resources Inc. has not maintained effective internal control over financial reporting as of December 31, 2012, based on the COSO criteria.

/s/ Ernst & Young LLP

Fort Worth, Texas
March 22, 2013

## ITEM 9B. Other Information

On November 1, 2011, we announced our redemption of substantially all of our outstanding 1.875% Convertible Subordinated Debentures due 2024 (the "Debentures"), and during the first quarter of 2012, we repurchased the remaining outstanding Debentures. The Indenture, dated as of November 1, 2004, as amended and supplemented (the "Convertible Debentures Indenture") between us and The Bank of New York Mellon Trust Company, N.A., as trustee (as successor in interest to JPMorgan Chase Bank, National Association), which governed the terms of the Debentures, was satisfied and discharged as of March 22, 2013.

The description of the Convertible Debentures Indenture is qualified in its entirety by reference to the provisions of the definitive agreement. A copy of the Convertible Debentures Indenture was filed as Exhibit 4.1 to our Current Report on Form 8-K filed on November 1, 2004 and is included as Exhibit 4.1 to this Form 10-K and incorporated by reference herein.

In July 2011, we received a subpoena duces tecum from the SEC requesting certain documents. The SEC has informed us that their investigation arises out of press releases in 2011 questioning the projected decline curves and economics of shale gas wells. In June 2012, we received an additional request from the SEC for certain information regarding our assessment for impairment of unevaluated properties and plans for development of unevaluated properties. In February 2013 we met with and provided additional information to the SEC.

# PART III

## ITEM 10. Directors, Executive Officers and Corporate Governance

The information concerning our directors set forth under "Corporate Governance Matters" in the proxy statement for our May 15, 2013 annual meeting of stockholders ("2013 Proxy Statement") is incorporated herein by reference. The information concerning any changes to the procedure by which a security holder may recommend nominees to the board of directors set forth under "Corporate Governance Matters – Committees of the Board" in the 2013 Proxy Statement is incorporated herein by reference. Certain information concerning our executive officers is set forth under the heading "Business – Executive Officers of the Registrant" in Item 1 of this Annual Report. The information concerning compliance with Section 16(a) of the Exchange Act set forth under "Section 16(a) Beneficial Ownership Reporting Compliance" in the 2013 Proxy Statement is incorporated herein by reference.

The information concerning our audit committee set forth under "Corporate Governance Matters – Committees of the Board" in the 2013 Proxy Statement is incorporated herein by reference.

The information regarding our Code of Business Conduct and Ethics set forth under "Corporate Governance Matters – Corporate Governance Principles, Processes and Code of Business Conduct and Ethics" in the 2013 Proxy Statement is incorporated herein by reference.

## ITEM 11. Executive Compensation

The information set forth under "Executive Compensation," "Corporate Governance Matters – Compensation Committee Interlocks and Insider Participation," "Corporate Governance Matters – Director Compensation for 2012" and "Certain Relationships and Related Transactions" in the 2013 Proxy Statement is incorporated herein by reference.

## ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information set forth under "Security Ownership of Management and Certain Beneficial Holders" in the 2013 Proxy Statement is incorporated herein by reference. The information regarding our equity plans under which shares of our common stock are authorized for issuance as set forth under "Equity Compensation Plan Information" in the 2013 Proxy Statement is incorporated herein by reference.

## ITEM 13. Certain Relationships and Related Transactions, and Director Independence

The information set forth under "Certain Relationships and Related Transactions" in the 2013 Proxy Statement is incorporated herein by reference.

Information regarding our directors' independence set forth under "Corporate Governance Matters – Independent Directors" in the 2013 Proxy Statement is incorporated herein by reference.

## ITEM 14. Principal Accountant Fees and Services

The information set forth under "Independent Registered Public Accountants" in the 2013 Proxy Statement is incorporated herein by reference.

## PART IV

### ITEM 15.

The following are filed as part of this Annual Report:

#### Financial Statements

See the index to the consolidated financial statements and related footnotes and other supplemental information included in Item 8 of this Annual Report, which identifies the financial statements filed herewith.

#### Financial Statement Schedules

All other schedules are omitted from this item because the information is inapplicable or is presented in the consolidated financial statements and related notes in Item 8 of this Annual Report.

## EXHIBIT INDEX

| Exhibit No. | Exhibit Description | Incorporated by Reference: Form | SEC File No. | Exhibit | Filing Date | Filed (†) or Furnished (‡) Herewith (as indicated) |
|---|---|---|---|---|---|---|
| 2.1* | Purchase Agreement, dated as of July 22, 2010, among First Reserve Crestwood Holdings LLC, Cowtown Gas Processing L.P., Cowtown Pipeline L.P. and Quicksilver Resources Inc. | 8-K | 001-14837 | 2.1 | 7/23/2010 | |
| 2.2* | Purchase Agreement Amendment No. 1, dated as of September 17, 2010, among First Reserve Crestwood Holdings LLC, Cowtown Gas Processing L.P., Cowtown Pipeline L.P. and Quicksilver Resources Inc. | 10-Q | 001-14837 | 2.2 | 11/8/2010 | |
| 3.1 | Amended and Restated Certificate of Incorporation of Quicksilver Resources Inc. filed with the Secretary of State of the State of Delaware on May 21, 2008 | S-3 | 333-151847 | 4.1 | 6/23/2008 | |
| 3.2 | Amended and Restated Certificate of Designation of Series A Junior Participating Preferred Stock of Quicksilver Resources Inc. | 10-Q | 001-14837 | 3.3 | 5/8/2006 | |
| 3.3 | Amended and Restated Bylaws of Quicksilver Resources Inc. | 8-K | 001-14837 | 3.1 | 11/16/2007 | |
| 4.1 | Indenture Agreement for 1.875% Convertible Subordinated Debentures Due 2024, dated as of November 1, 2004, between Quicksilver Resources Inc., as Issuer, and The Bank of New York, as Trustee (as successor in interest to JPMorgan Chase Bank, National Association) | 8-K | 001-14837 | 4.1 | 11/1/2004 | |
| 4.2 | First Supplemental Indenture, dated July 31, 2009, between Quicksilver Resources Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee | 10-Q | 001-14837 | 4.2 | 8/10/2009 | |
| 4.3 | Indenture, dated as of December 22, 2005, between Quicksilver Resources Inc. and The Bank of New York, as Trustee (as successor in interest to JPMorgan Chase Bank, National Association) | S-3 | 333-130597 | 4.7 | 12/22/2005 | |
| 4.4 | First Supplemental Indenture, dated as of March 16, 2006, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York, as Trustee (as successor in interest to JPMorgan Chase Bank, National Association) | 8-K | 001-14837 | 4.1 | 3/21/2006 | |
| 4.5 | Second Supplemental Indenture, dated as of July 31, 2006, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York, as Trustee (as successor in interest to JPMorgan Chase Bank, National Association) | 10-K | 001-14837 | 4.5 | 3/15/2010 | |

| | | | | | |
|---|---|---|---|---|---|
| 4.6 | Third Supplemental Indenture, dated as of September 26, 2006, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York, as Trustee (as successor in interest to JPMorgan Chase Bank, National Association) | 10-Q | 001-14837 | 4.1 | 11/7/2006 |
| 4.7 | Fourth Supplemental Indenture, dated as of October 31, 2007, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York, as Trustee (as successor in interest to JPMorgan Chase Bank, National Association) | 10-K | 001-14837 | 4.7 | 3/15/2010 |
| 4.8 | Fifth Supplemental Indenture, dated as of June 27, 2008, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Trust Company, N.A., as trustee | 8-K | 001-14837 | 4.1 | 6/30/2008 |
| 4.9 | Sixth Supplemental Indenture, dated as of July 10, 2008, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee | 8-K | 001-14837 | 4.1 | 7/10/2008 |
| 4.10 | Seventh Supplemental Indenture, dated as of June 25, 2009, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee | 8-K | 001-14837 | 4.1 | 6/26/2009 |
| 4.11 | Eighth Supplemental Indenture, dated as of August 14, 2009, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee | 8-K | 001-14837 | 4.1 | 8/17/2009 |
| 4.12 | Ninth Supplemental Indenture, dated as of December 23, 2011, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee | 10-K | 001-14837 | 4.12 | 4/16/2012 |
| 4.13 | Tenth Supplemental Indenture, dated as of December 23, 2011, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee | 10-K | 001-14837 | 4.13 | 4/16/2012 |
| 4.14 | Eleventh Supplemental Indenture, dated as of December 23, 2011, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee | 10-K | 001-14837 | 4.14 | 4/16/2012 |
| 4.15 | Twelfth Supplemental Indenture, dated as of December 23, 2011, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee | 10-K | 001-14837 | 4.15 | 4/16/2012 |
| 4.16 | Thirteenth Supplemental Indenture, dated as of February 28, 2012, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee | 10-Q | 001-14837 | 4.1 | 5/10/2012 |

| | | | | | |
|---|---|---|---|---|---|
| 4.17 | Fourteenth Supplemental Indenture, dated as of February 28, 2012, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee | 10-Q | 001-14837 | 4.2 | 5/10/2012 |
| 4.18 | Fifteenth Supplemental Indenture, dated as of February 28, 2012, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee | 10-Q | 001-14837 | 4.3 | 5/10/2012 |
| 4.19 | Sixteenth Supplemental Indenture, dated as of February 28, 2012, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee | 10-Q | 001-14837 | 4.4 | 5/10/2012 |
| 4.20 | Seventeenth Supplemental Indenture, dated as of June 13, 2012, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee | 10-Q | 001-14837 | 4.1 | 8/9/2012 |
| 4.21 | Eighteenth Supplemental Indenture, dated as of June 13, 2012, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee | 10-Q | 001-14837 | 4.2 | 8/9/2012 |
| 4.22 | Nineteenth Supplemental Indenture, dated as of June 13, 2012, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee | 10-Q | 001-14837 | 4.3 | 8/9/2012 |
| 4.23 | Twentieth Supplemental Indenture, dated as of June 13, 2012, among Quicksilver Resources Inc., the subsidiary guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee | 10-Q | 001-14837 | 4.4 | 8/9/2012 |
| 4.24 | Amended and Restated Rights Agreement, dated as of December 20, 2005, between Quicksilver Resources Inc. and Computershare Shareowner Services LLC (f/k/a Mellon Investor Services LLC), as Rights Agent | 8-A/A | 001-14837 | 4.1 | 12/21/2005 |
| 4.25 | Amendment dated as of February 23, 2011 to the Amended and Restated Rights Agreement between Quicksilver Resources Inc. and Computershare Shareowner Services LLC (f/k/a Mellon Investor Services LLC), as Rights Agent | 8-K | 001-14837 | 4.1 | 2/24/2011 |
| 4.26 | Amendment No. 2, dated as of March 8, 2013, to the Amended and Restated Rights Agreement between Quicksilver Resources Inc. and Computershare Shareowner Services LLC (f/k/a Mellon Investor Services LLC), as Rights Agent | 8-K | 001-14837 | 4.1 | 3/8/2013 |
| 10.1 | Wells Agreement dated as of December 15, 1970, between Union Oil Company of California and Montana Power Company | S-4/A | 333-29769 | 10.5 | 8/21/1997 |
| 10.2** | Quicksilver Resources Inc. Amended and Restated 2004 Non-Employee Director Equity Plan | 8-K | 001-14837 | 10.4 | 5/25/2007 |

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|---|---|---|---|---|---|---|
| 10.3** | Form of Non-Qualified Stock Option Agreement pursuant to the Quicksilver Resources Inc. Amended and Restated 2004 Non-Employee Director Equity Plan | 8-K | 001-14837 | 10.4 | 1/28/2005 | |
| 10.4** | Quicksilver Resources Inc. Sixth Amended and Restated 2006 Equity Plan | | | | | † |
| 10.5** | Form of Restricted Share Award Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended | 8-K | 001-14837 | 10.2 | 5/25/2006 | |
| 10.6** | Form of Restricted Stock Unit Award Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended | 8-K | 001-14837 | 10.2 | 11/24/2008 | |
| 10.7** | Form of Quicksilver Resources Canada Inc. Restricted Stock Unit Award Agreement (Cash Settlement) pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended | 8-K | 001-14837 | 10.3 | 11/24/2008 | |
| 10.8** | Form of Quicksilver Resources Canada Inc. Restricted Stock Unit Award Agreement (Stock Settlement) pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended | 8-K | 001-14837 | 10.4 | 11/24/2008 | |
| 10.9** | Form of Incentive Stock Option Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended | 10-K | 001-14837 | 10.9 | 4/16/2012 | |
| 10.10** | Form of Nonqualified Stock Option Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended | 10-K | 001-14837 | 10.10 | 4/16/2012 | |
| 10.11** | Form of Non-Employee Director Nonqualified Stock Option Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended (One-Year Vesting) | 8-K | 001-14837 | 10.8 | 5/25/2006 | |
| 10.12** | Form of Non-Employee Director Nonqualified Stock Option Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended (Three-Year Vesting) | 8-K | 001-14837 | 10.5 | 11/24/2008 | |
| 10.13** | Form of Non-Employee Director Restricted Share Award Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended (One-Year Vesting) | 8-K | 001-14837 | 10.7 | 5/25/2006 | |
| 10.14** | Form of Non-Employee Director Restricted Share Award Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended (Three-Year Vesting) | 8-K | 001-14837 | 10.2 | 5/25/2007 | |
| 10.15** | Quicksilver Resources Inc. 2011 Executive Bonus Plan | 8-K | 001-14837 | 10.1 | 2/25/2011 | |
| 10.16** | Quicksilver Resources Inc. 2012 Executive Bonus Plan | 8-K | 001-14837 | 10.1 | 4/19/2012 | |
| 10.17** | Description of 2011 Cash Bonuses | 10-K | 001-14837 | 10.17 | 4/16/2012 | |
| 10.18** | Quicksilver Resources Inc. Amended and Restated Change in Control Retention Incentive Plan | 8-K | 001-14837 | 10.9 | 11/24/2008 | |
| 10.19** | Quicksilver Resources Inc. Second Amended and Restated Key Employee Change in Control Retention Incentive Plan | 8-K | 001-14837 | 10.8 | 11/24/2008 | |

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|---|---|---|---|---|---|---|
| 10.20** | Quicksilver Resources Inc. Amended and Restated Executive Change in Control Retention Incentive Plan | 8-K | 001-14837 | 10.7 | 11/24/2008 | |
| 10.21** | Form of Director and Officer Indemnification Agreement (filed as Exhibit 10.2 to the Company's Form 10-Q filed on November 8, 2010 and included herein by reference) | 10-Q | 001-14837 | 10.2 | 11/8/2010 | |
| 10.22** | Letter to John C. Regan dated April 16, 2012 | | | | | † |
| 10.23** | Letter to Jeff Cook dated July 20, 2012 | 10-Q | 001-14837 | 10.1 | 11/8/2012 | |
| 10.24** | Employment Separation Settlement Agreement, dated August 9, 2012, between Quicksilver Resources Inc. and Jeff Cook | | | | | † |
| 10.25 | Credit Agreement, dated as of September 6, 2011, among Quicksilver Resources Inc. and the agents and lenders identified therein | 10-Q | 001-14837 | 10.1 | 11/9/2011 | |
| 10.26 | Amended and Restated U.S. Credit Agreement, dated as of December 22, 2011, among Quicksilver Resources Inc. and the agents and lenders identified therein | 8-K | 001-14837 | 10.1 | 12/27/2011 | |
| 10.27 | Credit Agreement, dated as of September 6, 2011, among Quicksilver Resources Canada Inc. and the agents and lenders identified therein | 10-Q | 001-14837 | 10.2 | 11/9/2011 | |
| 10.28 | Amended and Restated Canadian Credit Agreement, dated as of December 22, 2011, among Quicksilver Resources Canada Inc. and the agents and lenders identified therein | 8-K | 001-14837 | 10.2 | 12/27/2011 | |
| 10.29 | Omnibus Amendment No. 1 to Combined Credit Agreements, dated as of May 23, 2012, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and lenders identified therein | 10-Q | 001-14837 | 10.3 | 8/9/2012 | |
| 10.30 | Omnibus Amendment No. 2 to Combined Credit Agreements, dated as of August 6, 2012, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and lenders identified therein | 10-Q | 001-14837 | 10.4 | 8/9/2012 | |
| 10.31 | Omnibus Amendment No. 3 to Combined Credit Agreements, dated as of October 5, 2012, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and lenders identified therein | | | | | † |
| 10.32 | Asset Purchase Agreement, dated as of May 15, 2009, among Quicksilver Resources Inc., as Seller, and ENI US Operating Co. Inc. and ENI Petroleum US LLC, as Buyers | 8-K | 001-14837 | 10.1 | 5/19/2009 | |
| 10.33 | Project and Expenditure Authorization, dated as of April 6, 2011, between Quicksilver Resources Canada Inc. and Nova Gas Transmission Ltd. | 8-K | 001-14837 | 10.1 | 4/14/2011 | |
| 10.34 | PEA Amending Agreement, dated as of August 28, 2012, between Quicksilver Resources Canada Inc. and Nova Gas Transmission Ltd. | 8-K | 001-14837 | 10.1 | 9/10/2012 | |

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| 10.35 | Commitment Letter Agreement, dated as of April 6, 2011, between Quicksilver Resources Canada Inc. and Nova Gas Transmission Ltd. | 8-K | 001-14837 | 10.2 | 4/14/2011 | |
| 10.36 | Amendment to Commitment Letter Agreement, dated as of August 28, 2012, between Quicksilver Resources Canada Inc. and Nova Gas Transmission Ltd. | 8-K | 001-14837 | 10.2 | 9/10/2012 | |
| 10.37 | Contribution Agreement dated December 23, 2011 among Quicksilver Resources Canada Inc., Fortune Creek Gathering and Processing Partnership and 0927530 B.C. Unlimited Liability Company | 8-K | 001-14837 | 10.1 | 12/27/2011 | |
| 10.38 | Guaranty dated December 23, 2011 among Quicksilver Resources Inc., Fortune Creek Gathering and Processing Partnership and 0927530 B.C. Unlimited Liability Company | 8-K | 001-14837 | 10.2 | 12/27/2011 | |
| 10.39 | Gas Gathering Agreement, effective December 1, 2009, between Cowtown Pipeline L.P. and Quicksilver Resources Inc. | 8-K | 001-33631 | 10.1 | 1/8/2010 | |
| 10.40 | Amendment to Gas Gathering Agreement, dated as of October 1, 2010, by and between Quicksilver Resources Inc. and Cowtown Pipeline Partners L.P. | 10-K | 001-33631 | 10.2 | 2/25/2011 | |
| 10.41 | Sixth Amendment and Restated Gas Gathering and Processing Agreement, dated September 1, 2008, among Quicksilver Resources Inc., Cowtown Pipeline Partners L.P. and Cowtown Gas processing Partners L.P. | 10-Q | 001-33631 | 10.1 | 11/6/2008 | |
| 10.42 | Addendum and Amendment to Gas Gathering and Processing Agreement Mash Unit Lateral, effective January 1, 2009, among Quicksilver Resources Inc., Cowtown Pipeline Partners L.P. and Cowtown Processing Partners L.P. | 10-K | 001-33631 | 10.2 | 3/15/2010 | |
| 10.43 | Second Amendment to Sixth Amendment and Restated Gas Gathering and Processing Agreement, date as of October 1, 2010, by and among Quicksilver Resources Inc., Cowtown Pipeline Partners L.P. and Cowtown Gas Processing Partners L.P. | 10-K | 001-33631 | 10.2 | 2/25/2011 | |
| 10.44 | Amended and Restated Gas Gathering Agreement, effective September 1, 2008, between Cowtown Pipeline L.P. and Quicksilver Resources Inc. | 10-K | 001-14837 | 10.54 | 4/16/2012 | |
| 10.45 | First Amendment to Amended and Restated Gas Gathering Agreement, dated September 29, 2009, between Cowtown Pipeline L.P. and Quicksilver Resources Inc. | 10-K | 001-14837 | 10.55 | 4/16/2012 | |
| 10.46 | Second Amendment to Gas Gathering Agreement, dated October 1, 2010, between Cowtown Pipeline L.P. and Quicksilver Resources Inc. | 10-K | 001-14837 | 10.56 | 4/16/2012 | |
| 10.47*** | Acquisition and Exploration Agreement, dated September 20, 2012, between Quicksilver Resources Inc. and SWEPI LP | 8-KA | 001-14837 | 10.1 | 2/8/2013 | |
| 10.48 | First Amendment to Acquisition and Exploration Agreement, dated November 20, 2012, between Quicksilver Resources Inc. and SWEPI LP | | | | | † |

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|---|---|---|
| 21.1 | List of subsidiaries of Quicksilver Resources Inc. | † |
| 23.1 | Consent of Ernst & Young LLP | † |
| 23.2 | Consent of Deloitte & Touche LLP | † |
| 23.3 | Consent of Schlumberger Technology Corporation | † |
| 23.4 | Consent of LaRoche Petroleum Consultants, Ltd. | † |
| 31.1 | Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 | † |
| 31.2 | Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 | † |
| 32.1 | Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 | † |
| 99.1 | Report of Schlumberger Technology Corporation | † |
| 99.2 | Report of LaRoche Petroleum Consultants, Ltd. | † |
| 101.INS | XBRL Instance Document | ‡ |
| 101.SCH | XBRL Taxonomy Extension Schema Linkbase Document | ‡ |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase Document | ‡ |
| 101.LAB | XBRL Taxonomy Extension Labels Linkbase Document | ‡ |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document | ‡ |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase Document | ‡ |

* Excludes schedules and exhibits we agree to furnish supplementally to the SEC upon request
** Indicates a management contract or compensatory plan or arrangement
*** Portions of exhibit deleted pursuant to request for confidential treatment. These portions have been furnished separately to the Securities and Exchange Commission.

## SIGNATURES

Pursuant to the requirements of Section 13 of the Securities Exchange Act of 1934, the registrant has duly caused this Annual Report to be signed on its behalf by the undersigned, thereunto duly authorized.

Quicksilver Resources Inc.

By: /s/ Glenn Darden
Glenn Darden
President and Chief Executive Officer

Dated: March 22, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, the following persons on behalf of the registrant and in the capacities and on the dates indicated have signed this report below.

| Signature | Title | Date |
|---|---|---|
| /s/ Thomas F. Darden<br>Thomas F. Darden | Chairman of the Board; Director | March 22, 2013 |
| /s/ Glenn Darden<br>Glenn Darden | President and Chief Executive Officer (Principal Executive Officer); Director | March 22, 2013 |
| /s/ John C. Regan<br>John C. Regan | Senior Vice President - Chief Financial Officer and Chief Accounting Officer (Principal Financial and Accounting Officer) | March 22, 2013 |
| /s/ Anne Darden Self<br>Anne Darden Self | Director | March 22, 2013 |
| /s/ W. Byron Dunn<br>W. Byron Dunn | Director | March 22, 2013 |
| /s/ Steven M. Morris<br>Steven M. Morris | Director | March 22, 2013 |
| /s/ Yandell Rogers, III<br>W. Yandell Rogers, III | Director | March 22, 2013 |
| /s/ Mark J. Warner<br>Mark J. Warner | Director | March 22, 2013 |

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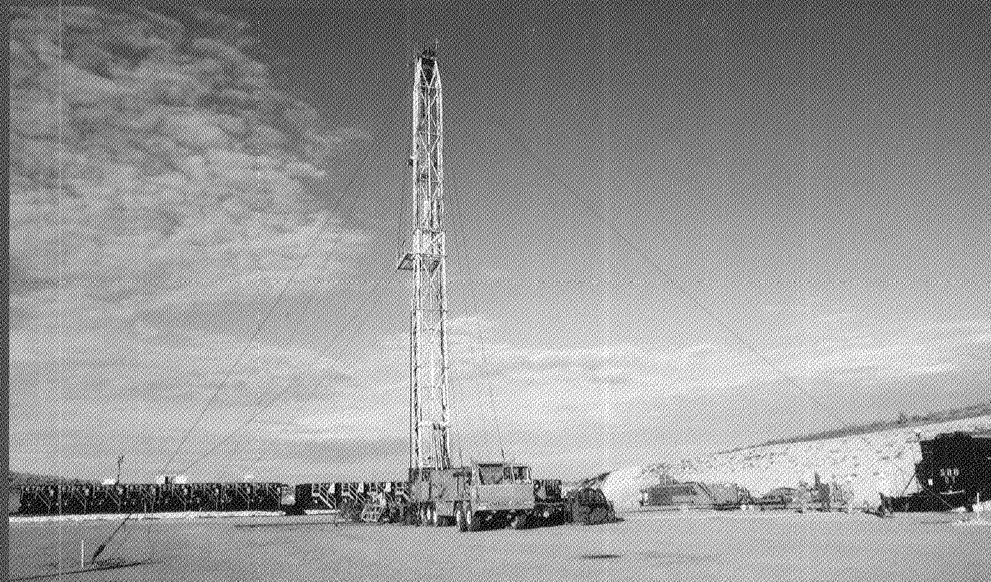
# CORPORATE INFORMATION



### DIRECTORS

Thomas F. Darden
*Chairman of the Board*
Glenn Darden
W. Byron Dunn*
Steven M. Morris*
W. Yandell Rogers III*
Anne D. Self
Mark J. Warner*

### CORPORATE OFFICERS

Thomas F. Darden
*Chairman of the Board*
Glenn Darden
*President & Chief Executive Officer*
John C. Cirone
*Executive Vice President, General Counsel and Secretary*
Stan G. Page
*Senior Vice President – U.S. Operations*
John C. Regan
*Senior Vice President – Chief Financial Officer and Chief Accounting Officer*
C. Clay Blum
*Vice President – U.S. Land*
John Callanan
*Vice President – Geology*
Scott Herstein
*Vice President – Acquisitions & Divestitures*
Vanessa G. LaGatta
*Vice President – Treasurer*
Chris M. Mundy
*Vice President – Chief Reservoir Engineer*
Clifford C. Rupnow
*Vice President – Midstream Development*
Anne D. Self
*Vice President – Human Resources*

***All information as of March 1, 2013***

### HEADQUARTERS

801 Cherry Street
Suite 3700, Unit 19
Fort Worth, Texas 76102
Phone: 817.665.5000
Fax: 817.665.5008
quicksilver@qrinc.com
www.qrinc.com

### MAJOR SUBSIDIARY

Quicksilver Resources Canada Inc.
One Palliser Square
2000, 125-9th Avenue, SE
Calgary, Alberta Canada
T2G 0P6
Phone: 403.537.2455
Fax: 403.262.6115

J. David Rushford
*Senior Vice President and Chief Operating Officer*

### REGISTRAR AND TRANSFER AGENT

Computershare
250 Royall Street
Canton, Massachusetts 02021
Phone: 866-637-5420
www.computershare.com

### INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Ernst & Young
201 Main Street, Suite 1100
Fort Worth, Texas 76102

### ANNUAL MEETING

The Company's Annual Meeting of Stockholders is scheduled for 9:00 a.m., May 15, 2013
The Fort Worth Club
306 West 7th Street
Fort Worth, Texas 76102

* ***Member of the Audit; Compensation; Health, Safety and Environmental; and Nominating and Corporate Governance Committees***

QUICKSILVER
RESOURCES

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Fort Worth, TX 76102
817.665.5000
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NYSE: KWK