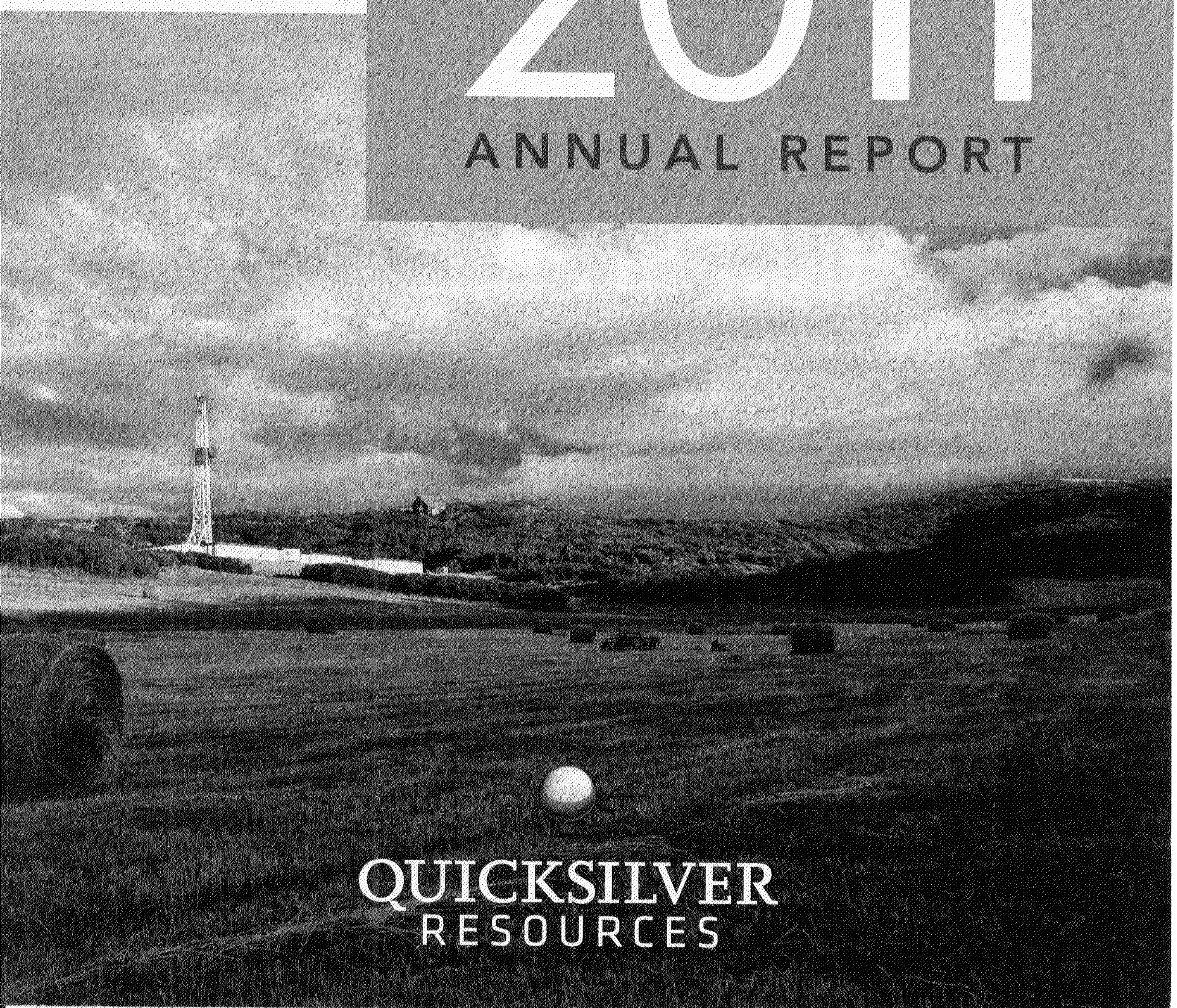
2011 ANNUAL REPORT



QUICKSILVER RESOURCES

COMPANY PROFILE

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 the Canadian province of British Columbia, and the coals in the Canadian province of Alberta. In addition, the company is pursuing high-potential exploratory opportunities in the Sandwash 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, 2011, the company has proved reserves of approximately 2.8 trillion cubic feet of natural gas equivalents, of which 77 percent is natural gas and 23 percent is natural gas liquids and oil; 69 percent are proved developed.

Quicksilver is a net asset value company focused on growth through the drill-bit by finding and developing long-life 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,

SINCE OUR BEGINNING more than 20 years ago in Michigan, Quicksilver Resources has pioneered the development of large-scale unconventional resource plays. Our proven track record has enabled us to successfully identify, build and develop projects in five different basins in North America, and we are poised to increase that number to seven, perhaps eight, basins in the near future.

Today Quicksilver has the largest inventory of projects in company history. We are using the same game plan of developing "grass roots" projects where we target areas through detailed technical analysis, then capture large acreage positions, drill test wells, build infrastructure, and move to full development. Our business is developing long-lived assets, and we can't take a quarter-to-quarter view.

2012 is an exciting year for the company in each of our operating areas. In British Columbia's Horn River Basin alone, the U.S. Geological Survey estimates a huge resource potential. We will highlight the value of this tremendous reservoir that we have helped de-risk. In December 2011, we entered into a partnership with KKR to fund our infrastructure build-out to ensure that Quicksilver is a low-cost producer in the basin, and we are also working to secure long-term pricing that will lock in billions of dollars of value for our shareholders. In addition, Quicksilver has hired advisors to secure an upstream partner to help develop this large-scale project.

Quicksilver is also working on several oil projects, and with more than 500,000 acres of prospective leasehold, we have exposure to substantial amounts of recoverable oil within three significant plays.

In the prolific Niobrara oil shale in Northwest Colorado, we are leveraging our expertise to unlock a portion of the shale's vast resource potential. We have tested commercial rates from our latest resource assessment wells, and this year, we plan to drill at least seven confirmation wells. We will also build out the initial infrastructure to maximize recovery of liquids from the high-BTU gas associated with the oil production. Our goal is to begin development drilling in earnest in 2013. The target is a 1,200-foot thick section of oil-charged shale and carbonates which holds a tremendous amount of oil in place. With continued success, this 210,000-acre project could be a complete "game changer" for the company.

Quicksilver Resources is also active in the Permian Basin in West Texas. In our 105,000-acre lease position, the "Wolfpack," we believe that there is enormous potential for our shareholders. Competitors surrounding this lease position are announcing commercial oil rates from vertical wells and higher rates from horizontal wells drilled into only a fraction of the thick oil-charged section of resource rock. We expect to begin our drilling in this area in the second quarter. We also are planning to bring in a partner to enable us to expand our position in the play and accelerate this project.

In Montana, competitors have announced production rates of several hundred barrels of oil per day from wells producing from the middle Bakken formation adjacent to our 175,000-acre, held-by-production leasehold in the Cut Bank field. We continue to watch this play develop around us. With no leasehold commitments, we have let others do the test drilling. But as this play heats up, we expect to do our own drilling in the near future.

By attacking both the upstream and midstream, we are using the same business template that has served us well throughout Quicksilver's history. By targeting more oil projects, we plan to have a more balanced product portfolio, increasing our liquids exposure significantly from the current 23% of total company reserves.

In the next 12 months, we are targeting public debt reduction of at least 25%. We are creating a subsidiary master limited partnership (MLP) that we hope to take public this summer. This entity will provide a way to monetize our mature assets, provide opportunities for our talented team, generate cash for Quicksilver to pay down debt, and provide another way for our shareholders to gain value.

Quicksilver's growth potential has never been stronger. Near-term opportunities in the Horn River, the Niobrara, the Permian, the Alberta Bakken and of course, our existing position in the Barnett, create added value and upside potential for existing and potential KWK shareholders.

In summary, our plan is solid and our outstanding team is pushing it forward. We have a strong hedge position for the next couple of years which will protect cash margins and sustain cash flows. We plan to increase oil production through these new projects and prepare to accelerate that growth in 2013 and beyond. We also plan to pay down significant amounts of debt through the launching of the MLP. Hitting these goals in 2012 will result in a much stronger company by year end.

We appreciate all of the guidance of our board of directors, the hard work of our fellow Quicksilver employees, and the support of our loyal 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	2011	2010	2009	2008	2007
Total revenue	$ 943.6	$ 928.3	$ 832.7	$ 800.6	$ 561.3
Net income (loss) attributable to Quicksilver [a]	$ 90.0	$ 445.6	$ (557.5)	$ (378.3)	$ 475.4
Net income (loss) per diluted share [a] [b]	$ 0.52	$ 2.50	$ (3.30)	$ (2.33)	$ 2.87
Diluted weighted average number of shares outstanding for the periods [b]	169.7	178.6	169.0	162.0	168.0
Total assets	$ 3,995.5	$ 3,507.7	$ 3,612.9	$ 4,498.2	$ 2,773.8
Long-term debt	$ 1,903.4	$ 1,746.7	$ 2,427.5	$ 2,586.0	$ 788.5
Total equity	$ 1,261.9	$ 1,069.9	$ 696.8	$ 1,211.6	$ 1,192.5
Natural gas production (Mmcf)	122,228	101,664	86,039	68,128	59,619
Average realized natural gas price per Mcf [c]	$ 4.95	$ 6.86	$ 7.42	$ 8.10	$ 6.73
NGL production (Mmcfe)	26,604	26,161	29,860	25,176	14,826
Average realized NGL price per Mcfe [c]	$ 6.44	$ 5.24	$ 4.55	$ 7.57	$ 7.21
Crude oil production (Mbbl)	273	303	425	483	584
Average realized price per Bbl [c]	$ 88.15	$ 71.90	$ 51.85	$ 78.83	$ 63.87

(a) 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. Net income attributable to Quicksilver and net income per diluted share for 2007 include $363.3 million and $2.16 per diluted share, respectively, associated with the gain on sale of all of our operations in Michigan, Indiana and Kentucky net of divestiture-related expenses and costs and the loss on related natural gas sales contracts.

(b) Share and per share amounts have been adjusted to reflect a two-for-one stock split during January 2008.

(c) 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, 2011

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, 2011, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $1,747,078,839 based on the closing sale price of $14.76 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 March 30, 2012
Common Stock, $0.01 par value per share	172,936,914 shares

DOCUMENTS INCORPORATED BY REFERENCE

Document	Parts Into Which Incorporated
Proxy Statement for the Registrant's May 16, 2012 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 equivalents
"**MMBbls**" means million barrels
"**MMBtu**" means million British Thermal Units, a measure of heating value, and is approximately equal to one Mcf of natural gas
"**MMBtud**" means MMBtu per day
"**Mcf**" means thousand cubic feet
"**Mcfe**" means Mcf natural gas equivalents, 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 equivalents
"**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
"**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
"**Bakken Asset**" means our operations and our assets in the Southern Alberta basin in the Bakken formation of northern Wyoming and Montana, including our Cutbank field operations and assets
"**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 of a 27.5% 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 in December 2011 with KKR dedicated to the construction and operation of natural gas midstream services within Horn River
"**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 Credit Agreement**" means the KGS senior secured revolving credit facility
"**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 the Kohlberg Kravis Roberts & Co. L.P. with whom we formed Fortune Creek
"**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
"**NGTL**" means NOVA Gas Transmission Ltd., a subsidiary of TransCanada PipeLines Limited
"**NGTL Project**" means the series of contracts with NGTL for the construction of a pipeline and meter station, which will serve our and others' operations in the Horn River basin
"**OSHA**" means Occupational Safety & Health Administration
"**Sandwash Asset**" means our operations and our assets in the Sandwash basin located in Colorado and southern Wyoming
"**SEC**" means the U.S. Securities and Exchange Commission
"**Senior Secured Second Lien Facility**" means our $700 million five-year senior secured second lien facility which we entered into pursuant to the Alliance Transaction that we subsequently repaid and terminated in June 2009
"**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 four areas: Jeff Davis and Reeves Counties, Upton and Crockett Counties, Pecos County and Presidio County

INDEX TO ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2011

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;
- uncertainties inherent in estimates of natural gas, NGL and oil reserves and predicting natural gas, NGL and oil 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;
- 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 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. 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 2.8 Tcfe at December 31, 2011. 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 exploration opportunities in North America, most notably in the following regions:

- Midland and Delaware basins in West Texas;
- Sandwash basin in Northwest Colorado; and
- Bakken formation in Montana and Wyoming.

In addition, our new ventures team actively studies other basins in North America which 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 15, 2012, members of the Darden family and entities controlled by them, beneficially owned more than 30% of our outstanding common stock.

STRATEGIC TRANSACTIONS IN THE LAST FIVE YEARS

On February 10, 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 expect this registration statement to become effective in 2012.

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 reduce the cost of processing and transporting gas to sales markets.

In October 2010, we sold all of our interests in KGS 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 in consideration of an earn-out on these assets and will recognize an additional gain in the first quarter of 2012. We believe the sale of these midstream assets allowed us to better focus on the development of our natural gas properties while redeploying the associated capital into projects with higher expected returns.

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 portions of our BBEP Units. At December 31, 2011, we no longer held any BBEP Units.

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 the KGS Secondary Offering which reduced our ownership in KGS from 73% to 61%.

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.

In 2007, we sold all of our oil and gas properties in Michigan, Indiana and Kentucky to BBEP for $750 million in cash and 21.3 million BBEP Units, valued at $724 million at the closing of the transaction, resulting in total proceeds at closing of $1.474 billion.

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:

Focus on core areas of repeatable, low-risk development: We believe that development activity in areas we have acquired a contiguous acreage position allows us to efficiently deploy our resources, manage our costs and leverage our technical expertise. Additionally, we endeavor to acquire acreage positions that are not only contiguous from a land perspectives, which is more efficient for drilling, but is also contiguous from a resource perspective, which will create a more economic asset for us.

Pursue disciplined organic growth opportunities: We typically plan to spend 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 significant expertise and a demonstrated history of identifying, developing and producing fractured shales, coal seams and tight sands. 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 build infrastructure to secure affordable gathering, processing, transportation, and operating costs. Finally, we move the project to the full development stage. We have historically monetized mature assets to provide financial flexibility for future projects. In 2012, we will continue to focus our development activities in the Barnett Shale. In Horn River, where we expect to convert our exploratory licenses covering more than 130,000 net prospective acres to leases with an expected 10-year term, we are in transition from the exploration phase to full development. Our exploration activities will be focused in the Sandwash basin, where we hold approximately 260,000 net acres, and in the Midland and Delaware basins of West Texas, where we hold approximately 155,000 net acres.

Enhance profitability through control and marketing of our equity natural gas and oil: We generally seek to maximize profitability by exercising control over the delivery of our production to distribution pipelines owned by third parties. We seek to achieve this by continuing to improve upon and add to our gathering and processing infrastructure during the infrastructure's development phase. We believe this allows us to better manage the physical movement of our production and the efficiency of our operations by decreasing dependency on third parties. We also monitor the spot markets for commodities and seek to sell our uncommitted production into the most attractive markets. Our partnership with KKR established an area of mutual interest that covers approximately 30 million potential acres in the Horn River, Cordova, and Liard basins in British Columbia and

Northwest Territories for potential midstream expansion. We expect this partnership will reduce our cost to process and transport our gas to sales markets by 44% as compared to other current alternatives. The backbone of the midstream infrastructure is in place for our Barnett Shale Asset and Horseshoe Canyon Asset.

Maintain a prudent capital structure to ensure financial flexibility: We believe that a flexible financial structure enables us to capitalize on opportunities and to limit our financial risk. We believe our internally-generated cash flows supplemented with asset monetization, joint ventures and borrowings under our Combined Credit Agreements provide us with the financial flexibility to pursue our acquisition, development and exploration programs. 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 derivative instruments. We regularly review the credit-worthiness of our hedging counterparties, and our hedging program is spread among numerous financial institutions, all of whom participated in our credit facilities at the time of entering into the hedge. We have entered into long-term hedges to provide predictability over longer periods.

BUSINESS STRENGTHS

High-quality asset base with long reserve life: Our proved reserves totaled approximately 2.8 Tcfe as of December 31, 2011 of which 69% were developed. Our Barnett Shale Asset has approximately 88% of our proved reserves and approximately 12% are located in our Horseshoe Canyon Asset and our Horn River Asset. These areas have a history of proven well performance and have established and emerging infrastructure to permit delivery of 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 2011 average production from all of our properties, our implied reserve life (proved reserves divided by annualized fourth-quarter 2011 production) was 18.4 years and our implied proved developed reserve life (proved developed reserves divided by annualized fourth-quarter 2011 production) was 12.7 years. As of December 31, 2011, almost 98% of our proved reserves were attributable to properties we operate.

Multi-year inventory of developmental drilling projects: As of December 31, 2011, we owned leases covering more than 580,000 net acres in our three core areas, of which 82% were classified as held by production. Within our Barnett Shale Asset alone, we have identified drilling locations that provide us greater than a 10-year inventory of drilling locations at the 2012 anticipated drilling rate. Our drilling success rate has averaged more than 99% during the past three years. We use 3D 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 gas resources. As of December 31, 2011, we have successfully drilled 10 gas wells and completed four gas wells in our Horn River Asset, and 80% of our licensed acreage has been validated. After completing our planned 2012 drilling in our Horn River Asset, we expect to be in a position to convert 98% of our licenses to 10-year leases. Our total proved reserves in our Horn River Asset are 99.3 Bcfe.

Proven record of organic growth in reserves and production: During the past three years, our proved reserves have grown 26% as we added 1.1 Tcfe of proved reserves from organic development activities. We supplemented this activity with acquisitions in the Barnett Shale and Horseshoe Canyon, which combined, total 147.3 Bcf of acquired proved reserves. We also sold 121 Bcf of proved reserves in the Eni Transaction in 2009. We have organically replaced 274% of our production during the three years ended December 31, 2011. Our growth has resulted from our ability to acquire attractive undeveloped acreage and to apply our technical expertise to find, develop and produce reserves. In recent years, we have demonstrated this ability through our accomplishments in our three core areas. We believe our current acreage position provides opportunities and flexibility to continue our organic growth of reserves and production.

Extensive technical experience and familiarity with developing and operating Barnett Shale properties and other unconventional resources. We are one of the five largest producers in the Barnett Shale. The development of the Barnett Shale helped pioneer unconventional shale development, and the Barnett Shale currently produces over 5.0 Bcf of natural gas per day with over 15,000 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 which 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.

Experienced management and technical team: Our CEO, Glenn Darden, and our Chairman, Thomas F. Darden, are founding members of our company and have held executive positions with us since our formation. They and our experienced executive management team have successfully implemented a disciplined growth strategy with a primary focus on net asset value growth through the development of unconventional reservoirs. Messrs. Glenn and Thomas Darden have been in the oil and natural gas business their entire professional careers and each has extensive experience in the acquisition, exploration, development, and production of oil and gas properties, as well as experience in the integration and management of energy assets in a reliable and cost-effective manner. Our executive management team is supported by a core team of technical, operational and financial managers who have significant industry experience, including experience in drilling and completing horizontal wells in unconventional reservoirs and in evaluating and completing strategic transactions.

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 are currently developing gathering and processing 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, 2011, we had total proved reserves of approximately 2.8 Tcfe, of which 77% is natural gas and 22% is NGLs. For 2011, we had total production of 150.5 Bcfe which averages to 413 MMcfed. In the last five years, we have grown our reserves and production at an approximate compound annual growth rate of 12% and 14%, respectively.

We believe the development of our leasehold interests in our core areas, and our exploration activities in the Sandwash basin and in West Texas will give us the flexibility over the next several years to grow reserves and production economically. 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 2012 capital program and our projected production levels can be found in Item 7 of this Annual Report.

Barnett Shale

Over 88% of our total proved reserves and over 81.6% of our total average daily production in 2011 were in our Barnett Shale Asset. In the fourth quarter of 2011, our net production from our wells in our Barnett Shale Asset was 338.0 MMcfed. We expect 74% of our 2012 production to come from our Barnett Shale Asset.

At December 31, 2011, we had approximately 140,000 net acres in the Barnett Shale of which approximately 55% 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 2011, sales of NGLs represented 22% of our Barnett Shale Asset production.

During 2011, we drilled 57 (49.9 net) wells and completed 128 (113.2 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, 2011, we had drilled a total of 1,030 (859.4 net) wells in our Barnett

Shale Asset since we began exploration and development operations in 2003. At December 31, 2011, we had two drilling rigs operating in our Barnett Shale Asset, but expect to utilize an average of one rig in the high-liquid acreage of Hood and Somervell Counties for the remainder of 2012.

West Texas

During 2011, 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. We now hold leases totaling 155,000 acres across Reeves, Pecos, Jeff Davis, Upton, Crockett and Presidio Counties. We plan to commence drilling operations in this area late in the first quarter of 2012.

Rockies

Our Rocky Mountain assets are located in the Bakken formation in Montana and Wyoming and the Niobrara formation in the Sandwash basin in Colorado. We have approximately 175,000 net acres in the Bakken formation, 68% of which is held by production. At December 31, 2011, proved reserves from these properties were 16.7 Bcfe, of which 92% was oil or NGLs.

We also hold approximately 260,000 net acres in the Sandwash basin where we are currently conducting exploratory activities and have two producing gas wells. During 2011, we drilled seven vertical wells followed by our first horizontal well in the fourth quarter of 2011, with initial production results of up to 500 Bbld produced from a 3,000 foot lateral. We plan to drill an additional four to seven horizontal wells in 2012, and plan to move the program to the development stage in 2013, pending positive well results. Total proved reserves in our Sandwash Asset are 0.3 Bcfe at December 31, 2011.

Daily production from all our properties in the Rocky Mountain region averaged 3.3 MMcfed for 2011.

Horseshoe Canyon

At December 31, 2011, our Horseshoe Canyon Asset proved reserves were 231.4 Bcfe, all of which was natural gas. Production averaged 58.5 MMcfed in our Horseshoe Canyon Asset, representing 14.2% of our total 2011 production.

In our Horseshoe Canyon Asset, as of December 31, 2011, we had 49,458 (36,929 net) undeveloped acres. During 2011 we spent $3.0 million for drilling and completion, largely funded by cash flows from operations from our Horseshoe Canyon Asset. Similar to 2011, we expect to completely fund 2012 drilling and completion activities in this asset with operating cash flows.

Horn River

We also have exploratory licenses which we expect to convert to leases in more than 130,000 net acres in Horn River. During 2011, we spent $95.0 million for drilling and completion costs on our Horn River Asset where we drilled and cased 10 wells and completed one well. As of December 31, 2011, we had four wells producing and 10 wells drilled and awaiting completion in our Horn River Asset, of which we expect eight wells to come online in 2012. Our production requires gathering, processing and transportation, for which we believe we have ample capacity to meet our needs for the foreseeable future. Our total proved reserves in our Horn River Asset were 99.3 Bcfe as of December 31, 2011, all of which was natural gas.

Quicksilver entered into agreements with NGTL whereby NGTL has agreed to construct and own a 60-mile, 36" pipeline extension from its Alberta system to our Fortune Creek Meter Station in order to transport Horn River natural gas to sales markets. We expect this extension will provide a low-cost transportation alternative to existing infrastructure, and will deliver gas to sales hubs, some of which historically have traded at a premium to Station 2 pricing where most Horn River basin gas is currently sold. NGTL expects to begin right-of-way clearing in January 2013, with construction expected to start at the end of 2013. The pipeline is expected to be in-service by June 2014. We have entered into agreements with NGTL to deliver up to 1 Tcf of production over a 10-year period starting in 2014. Our obligation may be reduced by delivery of volumes from third-party producers. We are further required to deliver pipeline-quality gas, which we plan to treat in facilities constructed by Fortune Creek.

OIL AND NATURAL GAS RESERVES

Our proved reserve estimates and related disclosures for 2011, 2010 and 2009 are presented in compliance with the SEC rule. The information with respect to our proved reserves and related disclosures have been prepared by Schlumberger Data & Consulting 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—Engineering, 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, 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 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 15 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 in accordance with the rule established by the SEC.

	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,		
	2011	2010	2009	2011	2010	2009	2011	2010	2009
Natural gas (MMcf)									
U.S.	1,244,187	1,312,777	1,044,140	584,717	628,946	511,894	1,828,904	1,941,723	1,556,034
Canada	299,371	242,941	223,300	31,260	22,947	29,753	330,631	265,888	253,053
Total	1,543,558	1,555,718	1,267,440	615,977	651,893	541,647	2,159,535	2,207,611	1,809,087
NGL (MBbl)									
U.S.	60,902	64,908	60,997	41,243	47,536	37,264	102,145	112,444	98,261
Canada	11	12	13	-	-	-	11	12	13
Total	60,913	64,920	61,010	41,243	47,536	37,264	102,156	112,456	98,274
Oil (MBbl)									
U.S.	2,545	2,775	2,467	490	533	392	3,035	3,308	2,859
Canada	-	-	-	-	-	-	-	-	-
Total	2,545	2,775	2,467	490	533	392	3,035	3,308	2,859
Total (MMcfe)									
U.S.	1,624,866	1,718,875	1,424,924	835,118	917,357	737,830	2,459,984	2,636,232	2,162,754
Canada	299,437	243,017	223,378	31,260	22,947	29,753	330,697	265,964	253,131
Total	1,924,303	1,961,892	1,648,302	866,378	940,304	767,583	2,790,681	2,902,196	2,415,885

	Years Ended December 31,		
	2011	2010	2009
Representative prices for reserve estimation purposes:			
Natural gas – Henry Hub, per MMBtu	$ 4.12	$ 4.38	$ 3.87
Natural gas – AECO, per MMBtu	3.65	4.08	3.76
NGL – Mont Belvieu, Texas, per Bbl	47.16	37.56	24.94
Oil – WTI Cushing, per Bbl	95.71	79.43	61.18
Standardized measure of discounted future net cash flows (1) (in millions)	$ 1,734.9	$ 1,786.4	$ 1,182.7

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

PROVED UNDEVELOPED RESERVES

Our 2011 drilling and completion activities related to our proved undeveloped locations as of December 31, 2010 were as follows:

	For the Year Ended December 31, 2011					
	Drilled		Completed		Producing	
	Gross	Net	Gross	Net	Gross	Net
Barnett Shale	49.0	41.9	32.0	27.1	32.0	27.1
Horseshoe Canyon	-	-	1.0	0.1	1.0	0.1
Total	49.0	41.9	33.0	27.2	33.0	27.2

Costs incurred in 2011 relating to the drilling and completion activities related to our proved undeveloped locations as of December 31, 2010 were $112.9 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 $2.8 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.

In our Horseshoe Canyon Asset, the gross capital costs for a typical well from pre-drilling preparation through the initiation of production generally range from $0.25 million to $0.35 million depending upon the number of coal seams and depth and distance to a gathering system. As our drilling and completion operations are limited by the restriction of the movement of rigs and other equipment due to wet weather and spring thaw, we expect to maintain an inventory of drilled wells awaiting completion and completed wells awaiting tie-in to sales lines.

In our Horn River Asset, we are in transition from the exploratory phase to a developmental focus, particularly in the southern portion of our acreage. Costs are and have been higher than we anticipate them to be in full development. In full development, we expect gross capital costs per well, from preparation of the multi-well drilling pad through the initiation of production, will generally range from $12 million to $14 million depending on factors such as the depth and lateral length of each well, number of stages of fracture stimulation and its distance to central facilities.

As of December 31, 2011, we had total proved undeveloped reserves of 866.4 Bcfe primarily comprised of 835.1 Bcfe in our Barnett Shale Asset on 341 well locations, 8.3 Bcfe in our Horseshoe Canyon Asset on 50 well locations, and 23 Bcfe in our Horn River Asset on two well locations. All of the 393 well locations are scheduled for development before the end of 2016.

Regionally, we estimate that our proved undeveloped well locations will be developed on the following timeline:

	Barnett Shale	Horseshoe Canyon	Horn River	Total
2012	44	1	2	47
2013	44	27	-	71
2014	126	17	-	143
2015	70	2	-	72
2016	57	3	-	60
Total	341	50	2	393

During 2012, we expect to spend $224.0 million to drill, complete and tie-in wells on proved locations. Estimated future development costs on proved locations as of December 31, 2011 are projected to be $154.1 million for 2013, $363.5 million for 2014, $211.1 million for 2015, and $191.5 million for 2016.

At December 31, 2011, none of our inventory of proved undeveloped drilling locations has been recognized as proved reserves for five years or longer. Currently, we anticipate that our proved undeveloped reserves will be developed within five years.

Proved undeveloped reserves in our Barnett Shale Asset decreased 9% from 2010 because a large portion of the 2011 capital program was directed to developing our proved undeveloped inventory.

DEVELOPMENT AND EXPLORATION ACTIVITIES AT YEAR END

At December 31, 2011, we had two drilling rigs operating in our Barnett Shale Asset, with both rigs operating on proved undeveloped locations. Additionally, completion work was in progress on nine (nine net) proved wells in our Barnett Shale Asset, with 58 (46.3 net) wells awaiting completion or tie-in to sales lines.

Two drilling rigs were operating on unproved locations in our Horn River Asset at December 31, 2011, with 10 (10 net) wells drilled and awaiting completion. Additionally, 145 (91.7 net) wells in our Horseshoe Canyon Asset were awaiting completion or tie-in to sales lines at December 31, 2011. Eight (eight net) wells in our Horn River Asset will be completed in 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,					
	2011		2010		2009	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development:						
U.S.						
Productive (1)	61.0	49.6	97.0	80.5	154.0	93.2
Non-productive	-	-	2.0	1.5	-	-
Canada						
Productive (2)	18.0	14.9	18.0	9.9	141.0	36.1
Non-productive	-	-	-	-	-	-
Total	79.0	64.5	117.0	91.9	295.0	129.3
Exploratory:						
U.S.						
Productive	8.0	6.0	-	-	4.0	4.0
Non-productive	-	-	-	-	-	-
Canada						
Productive	4.0	4.0	2.0	2.0	2.0	2.0
Non-productive	-	-	-	-	-	-
Total	12.0	10.0	2.0	2.0	6.0	6.0
Total:						
Productive	91.0	74.5	117.0	92.4	301.0	135.3
Non-productive	-	-	2.0	1.5	-	-
Total	91.0	74.5	119.0	93.9	301.0	135.3

(1) U.S. development drilling includes non-operated drilling of 4 wells (0.0 net), 3 wells (0.4 net) and 37 wells (3.0 net) for 2011, 2010 and 2009, respectively.

(2) Canadian development drilling includes non-operated drilling of 2 wells (1.0 net), 7 wells (0.4 net) and 88 wells (8.1 net) for 2011, 2010 and 2009, 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. Any shortfall we will fund with cash, however this is not expected to be material in the near-term.

Our prospective obligations under existing agreements are summarized below:

	Total	2012	2013	2014	2015	2016	Thereafter
				(In Mmcf)			
Gathering							
Barnett Shale	38,800	9,150	9,125	9,125	9,125	2,275	-
Horn River	857,699	36,882	53,027	84,845	106,068	195,838	381,039
Processing and Fractionation							
Barnett Shale	78,948	39,528	39,420	-	-	-	-
Horn River	130,014	13,400	20,400	22,227	22,227	22,227	29,533
Transportation							
Barnett Shale	487,566	113,396	95,207	75,167	73,307	66,493	63,996
Horseshoe Canyon	25,889	17,005	8,728	52	52	52	-
Horn River	1,085,754	7,693	17,262	48,049	57,183	57,340	898,227

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 $0.70 to $0.83 per Mcf of gathered volume but are subject to annual inflationary increases. Processing fees are fixed at $0.67 per Mcf, but 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 2011, Targa Liquids Marketing and Trade and Lone Star NGL Product Services LLC, the largest purchasers of our production, accounted for 15% and 11%, respectively, of our cash collected for natural gas, NGL and oils sales.

ACQUISITION, EXPLORATION AND DEVELOPMENT CAPITAL EXPENDITURES

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

	U.S.	Canada	Consolidated
		(In thousands)	
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
2009			
Proved acreage	$ 118	$ -	$ 118
Unproved acreage	11,300	2,658	13,958
Development costs	341,658	24,179	365,837
Exploration costs	32,798	59,402	92,200
Total	$ 385,874	$ 86,239	$ 472,113

PRODUCTIVE OIL AND GAS WELLS

The following table summarizes productive wells:

	As of December 31, 2011			
	Natural Gas		Oil	
	Gross	Net	Gross	Net
U.S.	1,091.0	907.4	198.0	194.0
Canada	2,869.0	1,391.6	4.0	1.1
Total	3,960.0	2,299.0	202.0	195.1

OIL AND GAS ACREAGE

Our principal natural gas and oil 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 was 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, 2011			
	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Barnett Shale	85,110	75,120	87,804	65,025
West Texas	2,432	2,233	221,456	150,882
Sandwash Basin	9,923	5,969	380,817	253,197
Southern Alberta Basin	109,783	102,583	79,401	64,492
U.S.	207,248	185,905	769,478	533,596
Horseshoe Canyon	467,380	293,879	49,458	36,929
Horn River Basin	11,634	11,016	130,146	119,453
Canada	479,014	304,895	179,604	156,382
Total	686,262	490,800	949,082	689,978

The following table summarizes information regarding the total number of net undeveloped acres as of December 31, 2011:

		2012 Expirations		2013 Expirations		2014 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	65,025	11,723	80	7,021	225	5,246	364
West Texas	150,882	6,205	-	5,914	420	52,744	30,207
Rockies	317,689	29,331	1,674	81,386	12,453	72,141	43,829
Canada	156,382	84,087	1,121	6,175	160	4,289	-
Total	689,978	131,346	2,875	100,496	13,258	134,420	74,400

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 feel will provide economic production 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 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 in which we operate, including Colorado, Montana, Texas and Wyoming, 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. In particular, in December 2011, the Railroad Commission of Texas and the Colorado Oil and Gas Conservation Commission finalized regulations requiring public disclosure of chemicals in fluids used in the hydraulic fracturing process. Similar regulations exist in British Columbia. Local ordinances or other regulations also may regulate or prohibit the performance of well drilling in general and hydraulic fracturing in particular, and may require baseline water well sampling. 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, which increased scrutiny could lead to heightened enforcement of existing regulations as well as the imposition of new air emission measures. In July 2011, the EPA proposed 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.

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 will require significant effort to quantify sources at all of our production sites, and beginning in 2012, we will be required 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

We make available for free on our internet website, www.qrinc.com, 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 as soon as reasonably practicable after we electronically file or furnish such material to the SEC. Additionally, charters for the committees of our Board and our Corporate Governance Guidelines and Code of Business Conduct and Ethics can be found on our internet 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.

EMPLOYEES

As of March 30, 2012, we had 477 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 March 30, 2012.

Name	Age	Position(s)
Thomas F. Darden	58	Director, Chairman of the Board
Glenn Darden	56	Director, President and Chief Executive Officer
Anne Darden Self	54	Director, Vice President - Human Resources
Jeff Cook	55	Executive Vice President - Operations
Philip W. Cook	50	Executive Vice President - Chief Financial Officer
John C. Cirone	62	Executive Vice President - General Counsel
Stan Page	54	Senior Vice President - U.S. Operations
John C. Regan	42	Vice President, Controller and Chief Accounting Officer
Chris M. Mundy	39	Vice President - Engineering
John D. Rushford	52	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. Messrs. Jeff Cook and Philip W. Cook are not related. 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. 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. Mr. Darden was previously employed by Mercury Exploration Company for 22 years in various executive level positions.

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.

JEFF COOK became our Executive Vice President – Operations in January 2006, after serving as our Senior Vice President – Operations since July 2000. From 1979 to 1981, he held the position of Operations Supervisor with Western Company of North America. In 1981, he became a District Production Superintendent for Mercury Production Company and became Vice President of Operations in 1991 and Executive Vice President in 1998 of Mercury Production Company before joining us.

PHILIP W. COOK became our Executive Vice President – Chief Financial Office in January 2012, after serving as our Senior Vice President – Chief Financial Officer since October 2005. Mr. Cook has also 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), since September 2011 and from January 2007 to October 2010. From October 2004 until October 2005, Mr. Cook served as President and Chief Financial Officer of a private chemical company. From August 2001 until September 2004, he served as Vice President and Chief Financial Officer of a private oilfield service company. From August 1993 to July 2001, he served in various executive capacities with Burlington Resources Inc. (subsequently merged with ConocoPhillips), a public independent oil and gas company engaged in exploration, development, production and marketing.

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 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.

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.

JOHN C. REGAN became our Vice President, Controller and Chief Accounting Officer in September 2007. He 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, where he was employed from 1994 to 2002.

CHRIS M. MUNDY became our Vice President – Engineering responsible for corporate reserves in August 2010, after serving as our 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 25 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. 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 2011. Among the factors that can cause these fluctuations are:

- domestic and foreign demand for oil and natural gas;
- 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 and climate change requirements;
- 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.

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 net present value of the underlying oil and gas reserves. We recognized impairment to the carrying value of our oil and gas properties in 2011, 2010 and 2009 of $49.1 million, $19.4 million and $979.5 million, respectively, and 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, including assumptions relating to economic factors. Any inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of proved reserves presented in our filings with the SEC.

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 petroleum prices and other factors that may be beyond our control.

At December 31, 2011, 31% 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 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 2011 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 estimate. 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, is not necessarily the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general will 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 and Horseshoe Canyon Asset account for 82% and 14% of our 2011 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 issuances of debt 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 or to maintain current production may be limited, resulting in decreased production 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, including the sale of equity interests in a master limited partnership, may be limited by our financial condition or general economic conditions at the time of any such financing or offering. 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.

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 adequately insured could 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 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 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 production and cash flows.

Producing oil and gas reservoirs 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. Our proved reserves will generally decline 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, results of operations would be adversely affected.

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

We deliver our production to market through gathering, fractionation and transportation systems that we do not own. 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 hedging policy may not effectively mitigate the impact of commodity price volatility on our cash flows, and our hedging activities could result in losses or limit our ability to benefit from price increases.

To reduce our exposure to hydrocarbon 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 hydrocarbon 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. If we choose not to enter into such commodity derivatives in the future, we could be more affected by changes in commodity prices than our competitors who engage in hedging arrangements.

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, demand and costs for drilling equipment, crews and associated supplies, equipment and services can increase significantly. We cannot be certain that in a higher petroleum 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 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;
- disposal wells;
- 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 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 other 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. 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 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, which increased scrutiny could lead 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. 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 July 2011, the EPA also proposed new air standards that would require measures to reduce volatile organic compound emissions at new hydraulically fractured natural gas wells and existing wells that are re-fractured. In addition, certain municipalities and states in which we operate, including Colorado, Montana, Texas and Wyoming, 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, in December 2011, the Railroad

Commission of Texas and the Colorado Oil and Gas Conservation Commission finalized regulations requiring public disclosure of chemicals in fluids used in the hydraulic fracturing process. Similar regulations exist in British Columbia. Local ordinances or other regulations also may regulate or prohibit the performance of well drilling in general and hydraulic fracturing in particular. Such laws and regulations may result in increased scrutiny or third-party claims, or otherwise result in operational delays, liabilities and increased costs.

Hydraulic fracturing requires significant quantities of water. Recently, Texas has been experiencing a drought. 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 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 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 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. 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 important 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 cannot assure you that we would be able to implement any of these strategies on satisfactory terms, if 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 financial 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.

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.

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 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 have agreed to provide NOVA Gas Transmission Ltd. ("NGTL") with letters of credit to cover its costs to construct a pipeline and meter station (the "project") that will connect the gas produced from our Horn River

Asset, to NGTL's Alberta System (the "Horn River Mainline"). Our financial exposure is staged in increments as the project is built and ultimately, the costs for the project are estimated to be C$257 million including taxes of approximately C$28 million. 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 99.3 MMcf of proved reserves our Horn River Asset as of December 31, 2011. 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.

If we do not make acquisitions on economically acceptable terms, our future growth will be limited.

In addition to expanding production from our current reserves, we may pursue acquisitions. If we are unable to make these acquisitions because we are: (1) unable to identify attractive acquisition candidates, to analyze acquisition opportunities successfully from an operational and financial point of view or to negotiate acceptable purchase contracts with them; (2) unable to obtain financing for these acquisitions on economically acceptable terms; or (3) outbid by competitors, then our future growth could be limited. Furthermore, even if we do make acquisitions, these acquisitions may not result in an increase in the cash generated by operations.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volume, revenue and costs, including synergies;
- an inability to integrate successfully the assets we acquire;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business matters;
- unforeseen difficulties operating in new product areas, with new customers, or new geographic areas; and
- customer or key employee losses at the acquired businesses.

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, 2011, we had 393 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 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 results of operations.

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. The owners of leasehold interests lying contiguous or adjacent to or adjoining any of our properties could take actions, such as drilling additional wells, which 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, operations conducted on adjacent or nearby wells could cause production from our wells to be shut in for indefinite periods of time for completion operations and other activities conducted on those properties, could result in increased lease operating expense and could adversely affect the production from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

Horn River is in an early stage of development and has limited infrastructure.

Our Horn River Asset is at an early stage of development. As such, there is limited information on reservoir quality and continuity which may affect the development schedule and well spacing requirements to fully recover the natural gas reserves. Additionally, the infrastructure in our Horn River Asset 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 covered by overlapping aboriginal rights claims. 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.

The recent adoption of 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. The U.S. Congress recently adopted comprehensive financial reform legislation that, among other things, establishes comprehensive federal oversight and regulation of over-the-counter derivatives and many of the entities that participate in that market. Although the Dodd-Frank Act was enacted on July 21, 2010, 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 its provisions relating to over-the-counter derivatives. While some of these rules have been finalized, many have not and, as a result, the final form and timing of the implementation of the new regulatory regime affecting commodity derivatives remains uncertain.

In particular, on October 18, 2011, the CFTC adopted final rules under the Dodd-Frank Act establishing position limits for certain, energy commodity futures and options contracts and economically equivalent swaps, futures and options. The position limit levels set the maximum amount of a contract that a trader may own or control separately or in combination, net long or short. The final rules also contain limited exemptions from position limits for certain bona fide hedging transactions and positions that were established in good faith before the initial limits become effective. The final rules became effective on January 17, 2012, but position limits will be phased in over time according to a specified schedule and the implementation of certain position limits is dependent on finalization of certain other rules to be jointly promulgated by the CFTC and the SEC. In addition, on December 2, 2011, the International Swaps and Derivatives Association, Inc. and the Securities Industry and Financial Markets Association filed a legal challenge to the final rules, claiming, among other things, that the rules may adversely impact commodities markets and market participants, including end-users, by reducing liquidity and increasing price volatility.

While the timing of implementation of the 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 they 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 certain over-the-counter derivatives that may have a material adverse effect on us. The Dodd-Frank Act will also subject certain 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. 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 Dodd-Frank swap dealers and major swap participants will be required to collect initial and variation margin from certain end-users of over-the-counter derivatives. While rules implementing many of these requirements have been proposed by relevant regulators, not all have 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. Posting of collateral 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 could therefore reduce our ability to execute strategic hedges to reduce commodity price uncertainty and thus 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.

Lastly, the Dodd-Frank Act requires, no later than 270 days after the enactment of the Act, the SEC to promulgate rules requiring SEC reporting companies that engage in the commercial development of oil, natural gas or minerals, to include in their annual reports filed with the SEC disclosure about all payments (including taxes, royalties, fees and other amounts) made by the issuer or an entity controlled by the issuer to the United States or to any non-U.S. government for the purpose of commercial development of oil, natural gas or minerals. As these rules are not yet effective, we are unable to predict what form these rules may take and whether we will be able to comply with them without adversely impacting our business, or at all. Any of these consequences could have a material adverse effect on our business, financial condition and results of operations.

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 15, 2012, 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 adopted 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 delayed or not completed, our stock price may decline and our growth potential may not be enhanced.

On October 19, 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"). On February 10, 2012, MLP 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 may change materially from those anticipated. If the transaction is not completed or 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 a material weakness in our internal controls that, if not properly corrected, could result in material misstatements in our financial statements.

We have identified a material weakness in our system of internal control over financial reporting as of December 31, 2011. 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.

The material weakness was related to the design and operating effectiveness of the computation of impairment of our non-oil and gas assets. Specifically, the weakness relates to design deficiencies regarding the assessment of triggering events and the consideration of asset groupings, as well as other deficiencies related to the performance and documentation of a recovery test and other fair value computational matters. In response to the identification of the material weakness, management has enhanced its process for documenting identification of impairment indicators, and the preparation and review of undiscounted recovery tests and discounted cash flow analyses. Significant deficiencies as of December 31, 2011 related to the Company's calculation of its asset retirement obligation and exclusion of certain future development costs from the depletion calculation. In response to the identification of the significant deficiencies, management has enhanced the process for preparation and review of the inputs to the asset retirement obligation and the depletion calculation. Management believes that these enhancements and improvements, when repeated as applicable in future periods, remediate the material weakness and significant deficiencies described above.

Although there can be no assurances, we believe these enhancements and improvements, when repeated in future periods, will remediate the control deficiencies described above. 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 and we may incorrectly report financial information, 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 2011 developments can be found in Item 1 of this Annual Report, which is incorporated herein by reference.

ITEM 3. Legal Proceedings

We are a defendant in lawsuits from time to time in the normal course of business. We are not party to any legal proceedings that, based on facts currently available, management believes will, individually or in the aggregate, have a material adverse effect on Quicksilver's business, operating results, financial condition or cash flows. In addition, allegations against our Executive Vice President – Operations in the District Court of Cleveland County, Oklahoma were dismissed on January 17, 2012.

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
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
2010		
Fourth Quarter	$ 15.88	$ 12.12
Third Quarter	14.47	10.65
Second Quarter	15.45	10.53
First Quarter	16.59	12.82

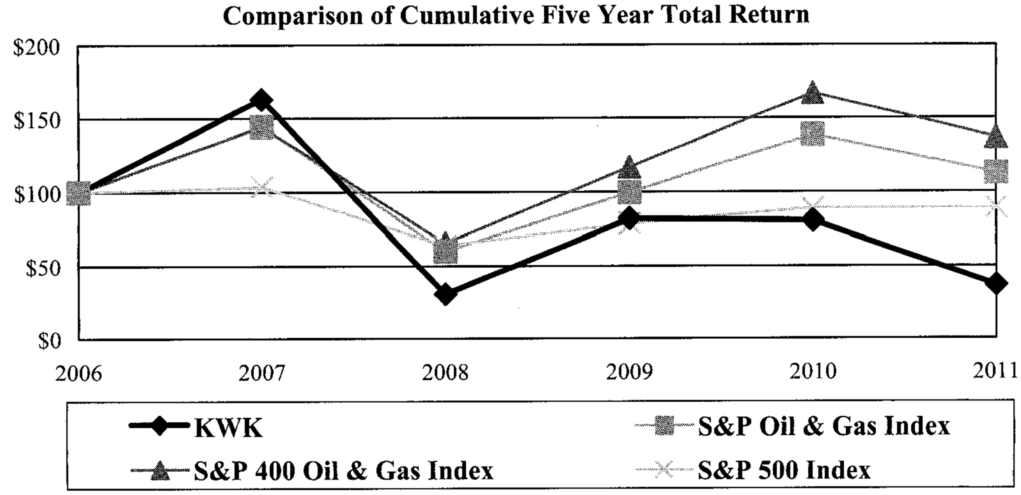
As of March 30, 2012, there were approximately 742 common stockholders of record.

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"), the Standard & Poor's 500 Exploration and Production Index (the "S&P 500 E&P Index", also commonly referred to as the "S&P Midcap Oil, Gas, and Consumable Fuels Index"), and the Standard & Poor's 400 Oil and Gas Index (the "S&P 400 Oil and Gas Index") for the period from December 31, 2006 to December 31, 2011, assuming an initial investment of $100 and the reinvestment of all dividends, if any. In 2011, we changed from using the published index, the S&P Midcap Oil, Gas, and Consumable Fuels Index, to the S&P 400 Oil and Gas Index because we believe the S&P 400 Oil and Gas Index is a closer representation of our peer group and thus will depict a more reasonable correlation of KWK returns to the peer average.

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, 2011.

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 2011	2,646	$7.58	-	-
November 2011	441	$8.14	-	-
December 2011	-	-	-	-
Total	3,087	$7.66	-	-

(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,				
	2011 (2)	**2010** (3) (7)	**2009** (4)	**2008** (5)	**2007** (6)
	(In thousands, except for per share data)				
Operating Results Information					
Total revenue	$ 943,623	$ 928,331	$ 832,735	$ 800,641	$ 561,258
Operating income (loss)	122,604	804,134	(613,873)	(249,697)	803,581
Income (loss) before income taxes	147,909	713,828	(836,856)	(585,077)	730,806
Net income (loss)	90,046	455,290	(545,239)	(373,622)	476,445
Net income (loss) attributable to Quicksilver	90,046	445,566	(557,473)	(378,276)	475,390
Diluted earnings (loss) per common share (1)	$ 0.52	$ 2.50	$ (3.30)	$ (2.33)	$ 2.87
Dividends paid per share	-	-	-	-	-
Financial Condition Information					
Property, plant and equipment - net	$3,460,519	$3,063,245	$2,542,845	$3,298,830	$1,866,540
Midstream assets held for sale - net	-	27,178	548,508	492,733	280,768
Total assets	3,995,462	3,507,734	3,612,882	4,498,208	2,773,751
Long-term debt	1,903,431	1,746,716	2,427,523	2,586,045	788,518
All other long-term obligations	495,939	248,762	121,877	282,101	434,190
Total equity	1,261,919	1,069,905	696,822	1,211,563	1,192,468
Cash Flow Information					
Cash provided by operating activities	$ 253,053	$ 397,720	$ 612,240	$ 456,566	$ 319,104
Capital expenditures	690,607	695,114	693,838	1,286,715	1,020,684

(1) Per share amounts have been adjusted to reflect a two-for-one stock split effected in the form of a stock dividend in January 2008.

(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 HCDS and certain 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.

(6) Operating income for 2007 include a gain of $628.7 million recognized from the divestiture of our Michigan, Indiana and Kentucky oil and gas properties and other assets and a charge of $63.5 million associated with a natural gas fixed-price sales contract that expired in March 2009 under which we no longer delivered natural gas produced from properties owned or operated by us.

(7) Note 2 to the consolidated financial statements in Item 8 contains additional information regarding the immaterial restatement to the 2010 results of operation primarily for the revised gain on sale of our interests in KGS and to a lesser extent additional depletion expense.

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.

Note 2 to the consolidated financial statements in Item 8 contains additional information regarding the immaterial restatement to the 2010 results of operations primarily for the restated gain on sale of our interests in KGS and to a lesser extent additional depletion expense. Accordingly, Management's Discussion and Analysis of Financial Condition and Results of Operations has been revised for the effects of the immaterial restatement.

Our MD&A includes the following sections:

- *Overview* – a general description of our business; the value drivers of our business; measurements; and opportunities, challenges and risks
- *2011 Highlights* – a summary of significant activities and events affecting Quicksilver
- *2012 Capital Program* – a summary of our planned capital expenditures during 2012
- *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

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, 2011, 77% and 22% 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 88%, 8% and 4%, respectively, of our proved reserves at December 31, 2011. During 2011, 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.

We focus on three key value drivers:

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

Our reserve growth 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. We will also continue to identify high-potential exploratory projects with comparatively higher levels of financial risk. 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,		
	2011	2010	2009
Organic reserve growth [1]	1%	19%	20%
Production volume (Bcfe)	150.6	129.6	118.5
Cash flow from operating activities (in millions)	$253.1	$397.7	$612.3
Diluted earnings (loss) per share	$ 0.52	$ 2.50	$ (3.30)

(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.

2011 HIGHLIGHTS

Master Limited Partnership

In October 2011, we announced our intention to file a registration statement on Form S-1 with the SEC in connection with the initial issuance of common units representing limited partner interest in a proposed master limited partnership (the "MLP"). We expect the MLP will use the proceeds from the sale of common units and borrowings under a planned new bank credit facility as consideration of certain of our Barnett Shale assets. We will retain a significant ownership position in the MLP and will own 100% of the general partner.

Fortune Creek

In December 2011, we announced the formation of Fortune Creek, a midstream partnership with KKR, dedicated to the construction and operation of midstream services to support us and potential producer customers primarily in British Columbia, Canada. The highlights of the transaction include:

- Our contribution of our existing 20-mile, 20-inch gathering line and compression facilities and 10-year contracts for gas deliveries into those facilities to the partnership;
- KKR's payment of $125 million to us in exchange for a 50% interest in the partnership;
- KKR will pay our portion of future development costs for the initial processing facility in exchange for preferential cash flow distributions to KKR;
- We will be the operator of the partnership;
- The partnership building and operating natural gas gathering, transportation and processing infrastructure to maximize the value of the production stream from our development in our Horn River Asset;
- Our dedication of current and future production from our Horn River Asset to the partnership;
- Our minimum capital commitment of $100 million for drilling and completion activities in our Horn River Asset for 2012, 2013 and 2014; and
- The formation of an area of mutual interest for the midstream business covering approximately 30 million potential acres in Horn River, Liard and Cordova basins in British Columbia and the Northwest Territories, which is expected to include third-party transportation and processing infrastructure and agreements.

New Credit Facilities

In September 2011, we terminated and replaced our \$1.0 billion global 2007 Senior Secured Credit Facility with new separate five-year syndicated senior secured revolving credit facilities for our U.S. and Canadian operations. The \$1.25 billion Initial U.S. Credit Facility had a borrowing base of \$850 million, including a letter of credit capacity of \$75 million, as of September 30, 2011. The C\$500 million Initial Canadian Credit Facility had a borrowing base of C\$225 million, including a letter of credit capacity of C\$100 million, as of September 30, 2011.

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 \$1.75 billion Combined Credit Agreements have a global borrowing base of \$1.075 billion, including a global letter of credit capacity of \$175 million, as of December 31, 2011.

We are currently working with our lending group of banks to establish a revolving credit facility for the MLP. When it becomes effective, we expect the borrowing base on the Combined Credit Facility to be reduced by \$200 million. We expect the MLP credit facility to have an initial borrowing base of \$275 million at the closing of the facility.

Convertible Debentures

On November 1, 2011, we repurchased substantially all of our outstanding convertible debentures for \$150.0 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.

Emerging Basins

We have built an acreage position of 260,000 acres in the Sandwash basin of northwestern Colorado in a 900- square mile fairway prospective for the Niobara and Lower Mancos Shales. We drilled and completed seven vertical wells through December 2011, and drilled our first horizontal well in the fourth quarter of 2011 with initial production results of 500 bbld and completed approximately 3,000 lateral feet, which is half of the length of the lateral we plan to ultimately drill. We expect to drill and complete four to seven horizontal wells in 2012.

We have also built a 155,000 acre position in the Midland and Delaware basins of West Texas prospective in the Bone Springs and Wolfcamp formations and principally concentrated in four core areas: Jeff Davis and Reeves Counties, Upton and Crockett Counties, Pecos County and Presidio County. In early 2012, we retained an investment bank to help evaluate the opportunities for a joint venture partner to help exploit our West Texas acreage.

Sale of BBEP Units

During 2011, we sold 15.7 million BBEP Units for aggregate proceeds of \$273.0 million, recognizing total gains of \$217.9 million in our income statement as other income. At December 31, 2011, we no longer owned any BBEP Units.

2012 CAPITAL PROGRAM

We expect our 2012 capital program to be spent in the following areas:

	Barnett Shale	Sandwash Basin	West Texas	Total U.S.	Horn River	Horseshoe Canyon	Total Canada	Total Company
				(In millions)				
Drilling and completion	\$ 94	\$ 31	\$ 25	\$ 150	\$ 146	\$ 6	\$ 152	\$ 302
Midstream	2	17	-	19	25	2	27	46
Leasehold evaluation and acquisition	12	4	5	21	-	1	1	22
Total budgeted capital	\$ 108	\$ 52	\$ 30	\$ 190	\$ 171	\$ 9	\$ 180	\$ 370

The chart above does not include approximately $40 million of overhead and interest expense that may be ordinarily capitalized and corporate and administrative capital.

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 among the several risks that we face. We seek to manage this risk by entering into derivative contracts which we strive to account for as hedges. 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 Sandwash Asset and our Bakken Asset.

Our audited net income is less than that reported in our press release of March 15, 2012. The difference is attributable to the following non-cash adjustments recorded after March 15, 2012: $3.0 million reduction in Other Revenue and long-term derivative assets due to recognition of additional credit risk associated with our counterparties; $3.0 million additional impairment charge for HCDS based on downward revisions to fair value; and the related tax impact for these adjustments.

Revenue

Production Revenue by operating area:

	Natural Gas			NGL			Oil			Total		
	2011	2010	2009	2011	2010	2009	2011	2010	2009	2011	2010	2009
						(In millions)						
Barnett Shale	$ 376.5	$ 321.2	$ 236.6	$ 216.6	$ 160.6	$ 135.5	$ 11.8	$ 11.8	$ 14.0	$ 604.9	$ 493.6	$ 386.1
Other U.S.	1.1	2.3	0.5	0.6	0.5	0.3	12.3	10.0	8.0	14.0	12.8	8.8
Hedging	100.2	250.2	213.1	(46.1)	(24.1)	-	-	-	-	54.1	226.1	213.1
U.S.	477.8	573.7	450.2	171.1	137.0	135.8	24.1	21.8	22.0	673.0	732.5	608.0
Horseshoe Canyon	79.2	90.4	88.0	0.1	0.2	0.1	-	-	0.1	79.3	90.6	88.2
Horn River	17.4	10.6	2.5	-	-	-	-	-	-	17.4	10.6	2.5
Hedging	30.8	22.7	98.0	-	-	-	-	-	-	30.8	22.7	98.0
Canada	127.4	123.7	188.5	0.1	0.2	0.1	-	-	0.1	127.5	123.9	188.7
Consolidated	$ 605.2	$ 697.4	$ 638.7	$ 171.2	$ 137.2	$ 135.9	$ 24.1	$ 21.8	$ 22.1	$ 800.5	$ 856.4	$ 796.7

Average Daily Production Volume by operating area:

	Natural Gas			NGL			Oil			Equivalent Total		
	2011	2010	2009	2011	2010	2009	2011	2010	2009	2011	2010	2009
		(MMcfd)			(Bbld)			(Bbld)			(MMcfed)	
Barnett Shale	261.8	207.9	168.3	12,117	11,913	13,598	352	433	729	336.6	281.9	254.2
Other U.S.	0.8	1.5	0.6	24	25	34	396	397	434	3.3	4.0	3 .4
U.S.	262.6	209.4	168.9	12,141	11,938	13,632	748	830	1,163	339.9	285.9	257.6
Horseshoe Canyon	58.4	61.2	64.9	6	8	5	-	-	2	58.5	61.2	64.9
Horn River	14.1	8.0	2.0	-	-	-	-	-	-	14.1	8.0	2.0
Canada	72.5	69.2	66.9	6	8	5	-	-	2	72.6	69.2	66.9
Consolidated	335.1	278.6	235.8	12,147	11,946	13,637	748	830	1,165	412.5	355.1	324.5

Average Realized Price by operating area:

	Natural Gas			NGL			Oil			Equivalent Total		
	2011	2010	2009	2011	2010	2009	2011	2010	2009	2011	2010	2009
	(per Mcf)			(per Bbl)			(per Bbl)			(per Mcfe)		
Barnett Shale	$ 3.94	$ 4.23	$ 3.85	$ 48.98	$ 36.93	$ 27.31	$ 91.83	$ 74.71	$ 52.62	$ 4.92	$ 4.80	$ 4.16
Other U.S.	4.06	4.16	3.62	72.92	56.04	27.02	84.87	68.77	50.53	11.65	8.68	7.41
Hedging	1.05	3.28	3.45	(10.41)	(5.53)	-	-	-	-	0.44	2.17	2.26
U.S.	$ 4.99	$ 7.51	$ 7.31	$ 38.61	$ 31.44	$ 27.30	$ 88.15	$ 71.87	$ 51.84	$ 5.42	$ 7.02	$ 6.47
Horseshoe Canyon	$ 3.71	$ 5.06	$ 3.71	$ 64.64	$ 66.03	$ 54.66	$ -	$ -	$ 54.80	$ 3.72	$ 5.07	$ 3.71
Horn River	3.39	3.64	3.43	-	-	-	-	-	-	3.39	3.64	3.43
Hedging	1.16	0.90	4.01	-	-	-	-	-	-	1.16	0.90	4.01
Canada	$ 4.81	$ 4.90	$ 7.72	$ 64.64	$ 66.03	$ 54.66	$ -	$ -	$ 54.80	$ 4.82	$ 4.90	$ 7.72
Consolidated	$ 4.95	$ 6.86	$ 7.42	$ 38.63	$ 31.46	$ 27.32	$ 88.15	$ 71.90	$ 51.85	$ 5.32	$ 6.61	$ 6.73

The following table summarizes the changes in our natural gas, NGL and oil revenue:

	Natural Gas	NGL	Oil	Total
		(In thousands)		
Revenue for 2009	$ 638,705	$ 135,940	$ 22,053	$ 796,698
Volume variances	59,534	(16,840)	(6,352)	36,342
Hedge settlement variances	(37,904)	(24,113)	-	(62,017)
Price variances	37,078	42,174	6,074	85,326
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
Revenue for 2011	$ 605,205	$ 171,265	$ 24,073	$ 800,543

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.

Natural gas revenue for 2010 increased from 2009 as a result of increases in production in our Barnett Shale Asset, which was primarily the result of wells brought online during 2010. Higher market prices for natural gas in 2010 also caused increased revenue, but were offset by a decrease from hedge contributions.

The small increase in NGL revenue for 2010 was due to increased market prices whose effect was reduced by payments made to settle hedges in 2010 and a decrease in production from our Barnett Shale Asset compared to 2009.

Sales of Purchased Natural Gas and Costs of Purchased Natural Gas

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Sales of purchased natural gas:			
Purchases from Eni	$ 71,921	$ 53,340	$ 11,195
Purchases from others	14,724	10,749	12,459
Total	86,645	64,089	23,654
Costs of purchased natural gas sold:			
Purchases from Eni	71,746	61,121	12,268
Purchases from others	13,652	10,825	11,265
Unrealized valuation (gain) loss on Gas Purchase Commitment	-	(6,625)	6,625
Total	85,398	65,321	30,158
Net sales and purchases of natural gas	$ 1,247	$ (1,232)	$ (6,504)

Our purchase and sale of Eni's natural gas production for 2011 and 2010 reflected a full year's activity as compared to six months' activity in 2009. Additionally, production has increased in our Alliance Asset, where Eni's working interests are located, because of new wells brought online throughout 2011 and 2010. As the Gas Purchase Commitment with Eni expired on December 31, 2010, no unrealized valuation gain or loss was recognized for the 2011 period. The Gas Purchase Commitment is more fully described in Note 3 to the consolidated financial statements in Item 8 of this Annual Report.

Other Revenue

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Midstream revenue:			
KGS	$ -	$ 6,512	$ 7,153
Canada	3,139	2,373	2,678
Other U.S.	1,018	1,352	2,683
Total midstream revenue	4,157	10,237	12,514
Unrealized gains on commodity derivatives	45,852	-	-
Gain (loss) from hedge ineffectiveness	5,928	(2,629)	(131)
Other	498	285	-
Total	$ 56,435	$ 7,893	$ 12,383

Other revenue increased compared to 2010 due to our recognition of $48.9 million in the 2011 period 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. We do not expect these charges to recur. 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. 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 impairment more fully discussed elsewhere in these results of operations). The increase in Canada is primarily the result of additional customers under contract for the transportation of natural gas. We had gains attributable to ineffectiveness of our production hedge derivatives for 2011 as compared to losses in 2010.

Other revenue for 2010 decreased as compared to 2009. Midstream revenue was lower for 2010 primarily as a result of the sale of our interests in KGS in October 2010 and lower volume on our HCDS. Losses attributable to ineffectiveness of our production hedge derivatives were greater for 2010 as compared to 2009.

Operating Expense

Lease Operating Expense

	Years Ended December 31,					
	2011		2010		2009	
	(In thousands, except per unit amounts)					
		Per Mcfe		Per Mcfe		Per Mcfe
Barnett Shale						
Cash expense	$ 62,158	$ 0.50	$ 47,231	$ 0.46	$ 41,538	$ 0.45
Equity compensation	904	0.01	841	0.01	761	0.01
	$ 63,062	$ 0.51	$ 48,072	$ 0.47	$ 42,299	$ 0.46
Other U.S.						
Cash expense	$ 6,327	$ 5.24	$ 5,945	$ 4.05	$ 6,348	$ 5.20
Equity compensation	224	0.19	182	0.12	195	0.16
	$ 6,551	$ 5.43	$ 6,127	$ 4.17	$ 6,543	$ 5.36
Total U.S.						
Cash expense	$ 68,485	$ 0.55	$ 53,176	$ 0.51	$ 47,886	$ 0.51
Equity compensation	1,128	0.01	1,023	0.01	956	0.01
	$ 69,613	$ 0.56	$ 54,199	$ 0.52	$ 48,842	$ 0.52
Horseshoe Canyon						
Cash expense	$ 29,853	$ 1.40	$ 27,221	$ 1.21	$ 27,881	$ 1.18
Equity compensation	461	0.02	1,271	0.06	2,114	0.09
	$ 30,314	$ 1.42	$ 28,492	$ 1.27	$ 29,995	$ 1.27
Horn River						
Cash expense	$ 2,947	$ 0.57	$ 2,145	$ 0.74	$ 190	$ 0.26
Equity compensation	-	-	-	-	-	-
	$ 2,947	$ 0.57	$ 2,145	$ 0.74	$ 190	$ 0.26
Total Canada						
Cash expense	$ 32,800	$ 1.24	$ 29,366	$ 1.16	$ 28,071	$ 1.15
Equity compensation	461	0.02	1,271	0.05	2,114	0.09
	$ 33,261	$ 1.26	$ 30,637	$ 1.21	$ 30,185	$ 1.24
Total Company						
Cash expense	$ 101,285	$ 0.67	$ 82,542	$ 0.63	$ 75,957	$ 0.64
Equity compensation	1,589	0.01	2,294	0.02	3,070	0.03
	$ 102,874	$ 0.68	$ 84,836	$ 0.65	$ 79,027	$ 0.67

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 for 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.

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. We expect the trend of lower unit lease operating expense in our Horn River Asset will continue in 2012.

Although U.S. lease operating expense for 2010 was higher than 2009, lease operating expense per Mcfe was unchanged from 2009 to 2010. Increased expense was the result of the increase in production volume in our Barnett Shale Asset for 2010 as compared to 2009.

Lease operating expense for 2010 in Canada was almost unchanged from 2009 despite a 3% increase in 2010 production compared to 2009. Lease operating expense for 2010 on a Canadian dollar basis increased C$1.7 million, or 4%, from 2009. Canadian lease operating expense on a Canadian dollar basis per Mcfe for 2010 increased less than 1% from 2009.

Gathering, Processing and Transportation Expense

	Years Ended December 31,					
	2011		2010		2009	
	(In thousands, except per unit amounts)					
		Per Mcfe		Per Mcfe		Per Mcfe
Barnett Shale	$ 172,128	$ 1.40	$ 82,976	$ 0.81	$ 42,678	$ 0.46
Other U.S.	70	0.05	22	0.01	11	0.01
Total U.S.	$ 172,198	$ 1.39	$ 82,998	$ 0.80	$ 42,689	$ 0.45
Horseshoe Canyon	4,157	0.19	4,867	0.22	4,803	0.20
Horn River	14,205	2.77	6,143	2.11	1,196	1.62
Total Canada	18,362	0.69	11,010	0.44	5,999	0.25
Total	$ 190,560	$ 1.27	$ 94,008	$ 0.73	$ 48,688	$ 0.41

GPT increased for 2011 compared to 2010 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.

GPT for 2010 compared to 2009 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. KGS' revenue, net of associated operating expense, averaged $18.5 million per quarter for the first three quarters of 2010. Fourth quarter 2010 GPT consisted primarily of fees charged by KGS. Canadian GPT increased for 2010 both in total dollars and on a per Mcfe basis primarily as a result of transportation fees associated with higher production from our Horn River Asset for 2010.

Production and Ad Valorem Taxes

	Years Ended December 31,					
	2011		2010		2009	
	(In thousands, except per unit amounts)					
Production taxes		Per Mcfe		Per Mcfe		Per Mcfe
U.S.	$ 8,983	$ 0.07	$ 9,171	$ 0.09	$ 4,746	$ 0.05
Canada	231	0.01	609	0.03	222	0.01
Total production taxes	9,214	0.06	9,780	0.07	4,968	0.04
Ad valorem taxes						
U.S.	$ 17,095	0.14	$21,797	0.21	$16,658	0.18
Canada	2,917	0.11	2,579	0.10	2,255	0.09
Total ad valorem taxes	20,012	0.13	24,376	0.19	18,913	0.16
Total	$ 29,226	$ 0.19	$34,156	$ 0.26	$23,881	$ 0.20

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 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 of the decrease. The remaining approximate $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.

Production taxes for 2010 reflect a 15% increase in realized prices before hedge settlements for production from our Barnett Shale Asset and an 11% increase in production volume from our Barnett Shale Asset when compared to 2009. Higher U.S. ad valorem taxes for 2010 reflect the addition of wells, particularly in areas with higher ad valorem tax rates, and increases to ad valorem tax rates assessed by taxing entities in Texas when compared to 2009. Production taxes for 2010 included $3.8 million of ad valorem taxes attributable to KGS. Production taxes in Canada increased in 2010 compared to 2009 due to increases in natural gas prices and increased production on freehold acreage.

Depletion, Depreciation and Accretion

	Years Ended December 31,					
	2011		2010		2009	
	(In thousands, except per unit amounts)					
Depletion		Per Mcfe		Per Mcfe		Per Mcfe
U.S.	$ 164,493	$ 1.33	$ 129,843	$ 1.24	$ 127,888	$ 1.36
Canada	38,228	1.44	38,825	1.54	33,782	1.38
Total depletion	202,721	1.35	168,668	1.30	161,670	1.36
Depreciation of other fixed assets:						
U.S.	$ 12,931	$ 0.10	$ 30,252	$ 0.29	$ 33,329	$ 0.35
Canada	7,415	0.28	4,698	0.19	3,952	0.16
Total depreciation	20,346	0.14	34,950	0.27	37,281	0.31
Accretion	2,696	0.02	3,585	0.03	2,436	0.02
Total	$ 225,763	$ 1.50	$ 207,203	$ 1.60	$ 201,387	$ 1.70

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. We expect that our consolidated depletion rate for 2012 will be approximately $1.40 per Mcfe. 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 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.

U.S. depletion expense for 2010 was greater than 2009 as an 11% increase in U.S. production was partially offset by a 4% decrease in the U.S. depletion rate. Changes in the U.S.-Canadian dollar exchange rate accounted for $3.7 million of the increase in Canadian depletion expense. Both our U.S. and Canadian depletion rates have been impacted by the impairment charges recognized during 2009. The Canadian depletion rate has been further impacted by evaluated Horn River Asset capital costs and future development costs included in proved reserve estimates at December 31, 2010.

The decrease in 2010 U.S. depreciation expense as compared to 2009 is the result of the sale of KGS. KGS' depreciation expense through September 2010 was $15.9 million as compared to $18.8 million for all of 2009.

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 performing our quarterly ceiling tests, we utilize first of month prices for the preceding 12 months. Due to the decrease in natural gas prices in the first quarter 2012 compared to the first quarter 2011, there is a significant likelihood of impairment of oil and gas properties. As of December 31, 2011, our U.S. and Canadian ceiling tests included $204 million and $104 million, respectively, in value for our derivatives treated as hedges of production. Absent this recognition, after tax we would have recognized $111 million of additional impairment expense for our U.S. oil and gas properties and $30 million for our Canadian oil and gas properties.

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 have been limited due to the lack of any substantial production history for the area.

We recognized non-cash charges totaling $979.6 million for impairments related to both our U.S. and Canadian oil and gas properties in 2009. The primary factor that caused the decrease in the future cash flows from our proved oil and gas reserves was lower benchmark natural gas prices at March 31, 2009 for the U.S. and Canada and further Canadian price decreases at June 30, 2009. The Canadian impairment also resulted from a near-term decrease in expected capital spending with a consequent reduction in near-term production and revenue.

At September 30, 2009, the unamortized cost of our Canadian oil and gas properties exceeded the full cost ceiling limitation by $38.8 million. As permitted by full cost accounting rules in effect at that date, improvements in AECO spot natural gas prices subsequent to September 30, 2009 eliminated the necessity to record a charge for impairment.

General and Administrative Expense

	Years Ended December 31,					
	2011		2010		2009	
	(In thousands, except per unit amounts)					
		Per Mcfe		Per Mcfe		Per Mcfe
Equity compensation	$ 19,272	$ 0.13	$ 22,144	$0.17	$ 17,043	$ 0.14
Litigation settlement	8,500	0.06	2,650	0.02	5,000	0.04
Strategic transactions	4,978	0.03	4,746	0.04	-	-
Other	46,832	0.31	50,567	0.39	55,200	0.47
Total	$ 79,582	$ 0.53	$ 80,107	$0.62	$ 77,243	$ 0.65

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.

General and administrative expense for 2010 was $2.9 million greater than 2009 due to an increase in stock-based compensation expense, which included $3.6 million for the vesting of all of KGS' unvested stock-based compensation at the time of its sale. Legal and professional fees for 2010, however, were $5.9 million lower than in 2009 primarily due to settlement of our litigation with BBEP in April 2010 and a decrease in litigation settlement costs. These decreases were partially offset by $2.5 million incurred in 2010 for transaction costs, principally investment banking and legal fees, related to the Crestwood Transaction.

We expect elevated levels of general and administrative expense in 2012 as there will be additional costs after the MLP becomes publicly traded, such as costs for director fees, listing fees and investor relations.

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.

Income from Earnings of BBEP

We record our portion of BBEP's earnings during the quarter in which its financial statements become publicly available. As a result, our 2011, 2010 and 2009 annual results of operations include BBEP's earnings for the 12 months ended September 30, 2011, 2010 and 2009, respectively. Additionally, 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 period 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.

Impairment of Investment in BBEP

During the first quarter of 2009, we evaluated our investment in BBEP for impairment in response to further decreases in prevailing commodity prices and the BBEP Unit price after December 31, 2008. As a result of these decreases, we made the determination that the decline in value was other-than-temporary. Accordingly, our impairment analysis, which utilized the March 31, 2009 closing price of $6.53 per BBEP Unit, resulted in aggregate fair value of $139.4 million for the portion of BBEP Units that we owned. The $139.4 million aggregate fair value was compared to the $241.5 million carrying value of our investment in BBEP. We recorded the difference of $102.1 million as an impairment charge during the first quarter of 2009. A similar analysis was performed at each subsequent quarter-end of 2009, 2010 and 2011, which resulted in no further impairment. Note 7 to our consolidated financial statements found in Item 8 of this Annual Report contains additional information regarding our investment in BBEP.

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.

Interest Expense

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Interest costs on debt outstanding	$ 172,696	$ 174,906	$ 154,961
Fees paid on letters of credit outstanding	1,674	971	735
Cash premium on early debt extinguishment	2,560	-	-
Add:			
Non-cash interest (1)	16,510	17,226	18,410
Non-cash loss on early debt extinguishment	-	-	27,122
Less: Interest capitalized	(7,416)	(4,750)	(6,127)
Interest expense	$ 186,024	$ 188,353	$ 195,101

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

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

Interest costs on debt outstanding for 2010 were higher than 2009 primarily because of the full year impact of the senior notes due 2016 and senior notes due 2019 being outstanding. Overall interest expense was lower in 2010 than 2009 due to the absence of $27.1 million of expense related to the early retirement of a portion of our debt in 2009. We do not have a practice of maintaining higher debt balances throughout the quarter and minimizing them at quarter end for financial reporting purposes.

Income Taxes

The U.S effective tax rates for the three years ended December 31, 2011 are as follows:

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Income (loss) before income taxes	$ 146,090	$ 708,081	$(744,053)
Income tax expense (benefit)	$ 53,599	$ 255,207	$(267,349)
Effective tax rate	36.69%	36.04%	35.93%

The Canadian effective tax rates for the three years ended December 31, 2011 are as follows:

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Income (loss) before income taxes	$ 1,819	$ 5,747	$ (92,803)
Income tax expense (benefit)	$ 4,264	$ 3,331	$ (24,268)
Effective tax rate	234.41%	57.96%	26.15%

The consolidated effective tax rates for the three years ended December 31, 2011 are as follows:

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Income (loss) before income taxes	$ 147,909	$ 713,828	$ (836,856)
Income tax expense (benefit)	$ 57,863	$ 258,538	$ (291,617)
Effective tax rate	39.12%	36.22%	34.85%

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 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. The increase in the Canadian effective tax rate for 2010 was primarily the result of an audit assessment of $1.0 million related to a predecessor's 1997 activities and other permanent items related to non-deductible expenses.

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 234.41%.

Our 2010 income tax provision increased from 2009 due primarily to higher income before taxes including the gain recognized on the sale of KGS and gains recognized from the disposition or sale of a portion of our BBEP Units. Also, the impact of permanent items for non-deductible expense impact the income tax rate applied to pre-tax income in 2010 and pre-tax loss in 2009. Additionally, we recognized an assessment of $1.0 million in Canada related to a predecessor's activities in 1997. The increase in our 2010 effective tax rate from the 2009 effective tax rate was primarily the result of U.S. and state income tax rates applied to the gains recognized from our sale of KGS and disposition of BBEP Units. For 2010, our effective rate in the U.S. was 36.0% and in Canada, excluding the $1.0 million assessment, it was 40.2%. Our U.S. operations generated 99% of our pre-tax income.

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, 2011. 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,		
	2011	2010	2009
		(In thousands)	
Net cash provided by operating activities	$ 253,053	$ 397,720	$ 612,303

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.

Net cash provided by operations for 2010 decreased from 2009, primarily due to our lower realized prices (including hedging effects), an increase in income tax payments and an increase in cash payments for interest. These reductions of operating cash were partially offset by a payment received for settlement of our BBEP litigation and an additional $9.8 million in BBEP distributions in 2010 as compared to 2009.

Investing Cash Flows

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Purchases of property, plant and equipment	$ (690,607)	$ (695,114)	$ (693,838)
Proceeds from sale of KGS	-	699,973	-
Proceeds from sale of BBEP units	272,965	34,016	-
Proceeds from sales of properties & equipment	4,163	9,953	220,974
Net cash provided (used) by investing activities	$ (413,479)	$ 48,828	$ (472,864)

For each of the three years ended December 31, 2011, 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 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. We completed several significant transactions during the years ended December 31, 2010 and 2009, including the Crestwood Transaction in 2010 with net cash proceeds of $700 million after transaction costs and the Eni Transaction in 2009 with net cash proceeds of $219.2 million.

Our 2011 capital expenditures include 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 Sandwash Asset and our Horn River Asset with expenditures of $36 million and $95 million, respectively. Leasehold expenditures reflected new acreage acquisitions in our Sandwash 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 relate 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 the oil and gas related expenditures compared to only 45% in 2011.

We reduced our 2009 exploration and development activity from 2008 levels in response to lower natural gas and NGL prices. Of the $693.8 million of cash paid for property, plant and equipment during 2009, 79% was invested in our oil and gas properties and 20% was invested in our gas gathering and processing operations. Our 2009 midstream capital investment of $123.0 million was primarily related to expansion of our gas processing and gathering facilities in our Barnett Shale Asset.

Financing Cash Flows

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Net borrowings	$ 12,714	$ (341,678)	$ (228,903)
Debt issuance costs	(12,506)	(3,111)	(32,472)
Partnership funds received	122,913	-	-
Gas Purchase Commitment	-	-	58,294
Gas Purchase Commitment repayments	-	(44,119)	(14,175)
Issuance of KGS common units	-	11,054	80,729
Distributions paid on KGS common units	-	(13,550)	(9,925)
Proceeds from exercise of stock options	1,299	1,801	4,046
Taxes paid on vesting of KGS equity compensation	-	(1,144)	(63)
Excess tax benefits on exercise of stock options	-	3,513	-
Purchase of treasury stock	(4,864)	(4,910)	(922)
Net cash provided (used) by financing activities	$ 119,556	$ (392,144)	$ (143,391)

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.

Net financing cash flows for 2009 reflect our efforts to restructure and reduce our debt outstanding at December 31, 2008. In 2009, we received total proceeds of $873.1 million from the issuance of our senior notes due 2016 with a principal amount of $600 million and our senior notes due 2019 with a principal amount of $300 million. The senior notes due 2016 bear interest at the rate of 11.75% paid semiannually on January 1 and July 1. The senior notes due 2019 bear interest at the rate of 9.125% paid semiannually on February 15 and August 15. Borrowings and repayments in 2009 under the 2007 Senior Secured Credit Facility were $492 million and $890 million, respectively, which resulted in a net decrease of $398 million outstanding in 2009. KGS increased borrowings under the KGS Credit Agreement by $49.5 million in 2009. Proceeds from the debt issuances and the Eni Transaction in 2009 were used to repay and terminate the remaining indebtedness under our Senior Secured Second Lien Facility and to repay a portion of the outstanding borrowings under the 2007 Senior Secured Credit Facility. The KGS Secondary Offering, completed in December 2009, resulted in net proceeds of $80.3 million.

Liquidity and Borrowing Capacity

In September 2011, we terminated and replaced our $1.0 billion global 2007 Senior Secured Credit Facility with new five-year separate syndicated senior secured revolving credit facilities for our U.S. and Canadian operations. In December 2011, these facilities were amended and restated into the Combined Credit Agreements. “2011 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, including market prices for our products. Any future inability to comply with these covenants, unless waived 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.

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 believe that our capital resources are adequate to meet the requirements of our existing business. We anticipate that our 2012 capital program will be substantially funded by cash flow from operations, but expect that we will also draw on the Combined Credit Agreements. We are also pursuing joint ventures partners in our West Texas Asset and Horn River Asset.

Depending upon conditions in the capital markets and other factors, we will from time to time consider the issuance of debt or other securities, other possible capital markets transactions or the sale of assets, 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 on hand and from operations, bank borrowings, the issuance of debt or other securities or a combination of those sources.

Financial Position

The following impacted our balance sheet as of December 31, 2011, as compared to our balance sheet as of December 31, 2010:

- Our net property, plant and equipment balance increased $397 million from December 31, 2010 to December 31, 2011. We incurred capital expenditures of $694.5 million during 2011 and also recognized assets for retirement obligations established for new wells and facilities. DD&A and impairment expense and changes to U.S.—Canadian exchange rates reduced our property, plant and equipment balances $330.1 million and $13.6 million, respectively.
- The valuation of our current and non-current derivative assets and liabilities was $196 million higher on a net basis at December 31, 2011 as compared to December 31, 2010. The increase was primarily the result of recognized unrealized gains of $48.9 million associated with our 10-year natural gas price swaps prior to their designation as hedges and deferred unrealized gains of $229.1 million recognized in OCI partially offset by settlements received of $84.8 million.
- Our investment in BBEP Units decreased $83.3 million during 2011. In addition to recognizing $8.4 million in net losses from the earnings of BBEP, we received $19.8 million in dividends from BBEP and retired $55.1 million of our investment balance in connection with the sale of all our remaining 15.7 million BBEP Units.
- Long-term debt increased $156.7 million from net borrowings under our Combined Credit Agreements. We offset these borrowings with the repurchase of $150.0 million of our convertible debentures, and the repurchase of $48.4 million of our senior notes due 2015, 2016 and 2019.

Contractual Obligations and Commercial Commitments

Contractual Obligations

Information regarding our contractual and scheduled interest obligations, at December 31, 2011, 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	$ 1,904,120	$ 18	$ 438,000	$ 1,168,102	$ 298,000
Scheduled interest obligations	762,227	166,639	484,739	66,743	44,106
GPT contracts	1,030,412	67,341	337,796	291,947	333,328
Drilling rig contracts	24,754	23,948	806	-	-
Purchase obligations	11,355	11,355	-	-	-
Asset retirement obligations	76,442	254	1,424	950	73,814
Unrecognized tax benefits	9,219	9,219	-	-	-
Operating lease obligations	40,747	5,484	13,351	6,570	15,342
Total obligations	$ 3,859,276	$ 284,258	$ 1,276,116	$ 1,534,312	$ 764,590

- *Long-Term Debt.* As of December 31, 2011, 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, 2011, we anticipate interest payments, including our scheduled interest obligations, to be $167 million in 2012.
- *Scheduled Interest Obligations.* As of December 31, 2011, 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 $9.0 million annually on our Combined Credit Agreements.
- *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 require payment of a specified day rate ranging from $12,500 to $27,005 for the entire lease term regardless of our utilization of the drilling rigs.
- *Purchase Obligations.* At December 31, 2011, 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.
- *Unrecognized Tax Benefits.* We have recorded obligations that have resulted from tax benefit claims in our tax returns that do not meet the recognition standard of more likely than not to be sustained upon examination by tax authorities. At December 31, 2011, $9.0 million of the unrecognized tax benefits, if recognized, would reduce our effective tax rate.
- *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, 2011:

	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	$ 9,072	$ 9,072	$ -	$ -	$ -
Standby letters of credit	49,421	49,421	-	-	-
Total	$ 58,493	$ 58,493	$ -	$ -	$ -

- *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 $32.1 million related to the NGTL Project as of December 31, 2011. All of these letters of credit were issued under our Combined Credit Agreements and generally have an annual renewal option. During 2012, we expect our utilization of letters of credit to increase in support of the NGTL Project and transportation contracts in our Horn River Asset by approximately $84.0 million.

Project and Expenditure Authorization

In April 2011, we entered into a Project and Expenditure Authorization ("PEA") with NGTL, which supports the NGTL 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 PEA, we agreed to provide financial assurances to cover NGTL's costs for the NGTL Project, estimated to be C$257.4 million including taxes of approximately C$27.6 million, which is estimated to occur in stages based on NGTL's forecast of the NGTL Project costs, in the following cumulative amounts:

	NGTL Cumulative Financial Assurances [1]	
	(C$ in thousands)	(US$ in thousands)
July 1, 2012	$ 68,264	$ 67,124
October 1, 2012	109,816	$ 107,982
July 1, 2013	148,400	$ 145,922
October 1, 2013	257,400	$ 253,101

(1) A letter of credit for C$32.6 million is outstanding for the NGTL Project as of December 31, 2011.

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 NGTL Project.

The PEA may be terminated prior to completion of the NGTL Project for various reasons, including the failure to obtain NEB approval upon terms and conditions satisfactory to NGTL. Upon early termination, 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. In the event that the termination occurs, we would pay those costs plus approximately C$26 million with the option to purchase 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 NGTL 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. Under the current rule adopted by the SEC in December 2008, we incorporated the following changes into our proved reserve process and related disclosures for 2011, 2010 and 2009:

- the use of 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;
- consideration of and limitations on the types of technologies that may be used to reliably establish and estimate proved reserves;
- reporting of investments and progress made during the year to convert proved undeveloped reserves to proved developed reserves; and,
- reporting on the independence and qualifications of our personnel and independent petroleum engineers who are responsible for the preparation of our reserve estimates.

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. Our proved reserve estimates and related disclosures for 2011, 2010 and 2009 are presented in compliance with this new rule.

The current SEC rule allows the recognition of PUD reserves to be booked beyond one offset location where reliable technology exists that establishes reasonable certainty of economic producibility at greater distances, whereas the prior rule allowed recognizing only one offset. In accordance with the current rule, we recognized incremental PUD locations in our Barnett Shale Asset. In our Barnett Shale Asset, we had 341 proved undeveloped gas well locations at December 31, 2011, including 60 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 3% 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 a ceiling test-related impairment. 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 financial derivatives that hedge 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%.

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 financial derivative instruments to mitigate risk associated with the prices received from our production. We may also utilize financial derivative instruments to hedge the risk associated with interest rates on our outstanding debt. We account for our derivative instruments by recognizing qualifying derivative instruments on our balance sheet as either assets or liabilities 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 derivative instruments that qualify as cash flow hedges, the effective portions of gains or losses are deferred in accumulated other comprehensive income and recognized in earnings during the period in which the hedged transactions are realized. Gains or losses on qualified derivative instruments terminated prior to their original expiration date are deferred and recognized as income or expense in the period in which the hedged transaction is recognized. If the hedged transaction becomes probable of not occurring, the deferred gain or loss is immediately recorded to earnings. The ineffective portion of the hedge relationship is recognized currently as a component of other revenue.

The fair values of natural gas and NGL derivatives are estimated using published market prices of natural gas and NGLs for the periods covered by the contracts. Estimates are determined by applying the net differential between the prices in each derivative and market prices for future periods, to the volume stipulated in each contract to arrive at an estimated value of future cash flow streams. These estimated future cash flow values are then discounted for each contract at rates commensurate with federal treasury instruments with similar contractual lives to arrive at estimated fair value.

For derivative instruments that qualify as fair value hedges the gains or losses on the derivative instruments are recognized currently in earnings and the changes in value of the hedged items are also recognized currently in earnings. Any gains or losses on the derivative instruments not offset by the gains or losses on the hedged items are recognized as the value of ineffectiveness in the hedge relationships. For interest rate swaps that qualify as fair value hedges of our fixed-rate debt outstanding, ineffectiveness is recognized currently as a component of interest expense.

The fair value of all interest rate derivatives is estimated using published LIBOR interest rates for the periods covered by the contracts. The estimates are determined by applying the net differential between the interest rate in each derivative and interest rates for future periods, to the notional amount stipulated in each contract to arrive at estimated future cash flow streams.

We enter into derivatives with counterparties who are our lenders. 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 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 and provide judgment on the amount of financial statement benefit that an uncertain tax position will realize upon ultimate settlement. To the extent that we believe that a more than 50% probability exists that some portion or all of the deferred tax assets will not be realized, we must establish a valuation allowance. Significant management judgment is required in determining any valuation allowance recorded against deferred tax assets and in determining the amount of financial statement benefit to record for uncertain tax positions. We consider all available evidence, both positive and negative, to determine whether, based on the weight of the evidence, a valuation allowance is needed and 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. Evidence used for the valuation allowance includes information about our current financial position and results of operations for the current and preceding years, as well as all currently available information about future years, including our anticipated future performance, the reversal of deferred tax assets and liabilities and tax planning strategies available to us. To the extent that a valuation allowance or uncertain tax position is established or changed during any period, we would recognize expense or benefit within our consolidated tax expense.

OFF-BALANCE SHEET ARRANGEMENTS

Our contracts with NGTL provide financial assurances to it during the construction phase of the NGTL Project, which is expected to continue through 2014. Assuming the project is fully constructed at estimated costs of C$257.4 million, we expect to provide letters of credit through 2014. 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, 2011, the following forecasted production has been hedged with price collars or price swaps.

Production Year	Daily Production Volume	
	Gas	NGL
	MMcfd	MBbld
2012	165	7
2013	105	-
2014-2015	65	-
2016-2021	35	-

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 $84.8 million, $248.9 million and $310.9 million for 2011, 2010 and 2009, respectively.

The following table details our open derivative positions at December 31, 2011:

Country	Product	Type	Remaining Contract Period	Volume	Weighted Avg Price Per Mcf or Bbl	Fair Value						
						Total	2012	2013	2014	2015	2016	Thereafter
									(In thousands)			
US	Gas	Collar	Jan 2012-Dec 2012	20 MMcfd	$6.50-7.15	23,862	23,862	-	-	-	-	-
US	Gas	Collar	Jan 2012-Dec 2012	20 MMcfd	6.50-7.18	23,963	23,963	-	-	-	-	-
US	Gas	Collar	Jan 2012-Dec 2012	20 MMcfd	6.50-8.01	23,803	23,803	-	-	-	-	-
Canada	Gas	Swap	Jan 2012-Dec 2013	10 MMcfd	$ 5.00	10,290	6,441	3,849				
Canada	Gas	Swap	Jan 2012-Dec 2021	10 MMcfd	6.22	44,330	10,807	8,080	6,543	5,542	4,588	8,770
Canada	Gas	Swap	Jan 2012-Dec 2021	5 MMcfd	6.20	21,832	5,367	4,005	3,237	2,737	2,261	4,225
Canada	Gas	Swap	Jan 2012-Dec 2021	5 MMcfd	6.20	21,832	5,367	4,005	3,237	2,737	2,261	4,225
US	Gas	Swap	Jan 2012-Dec 2013	10 MMcfd	5.00	10,290	6,441	3,849	-	-	-	-
US	Gas	Swap	Jan 2012-Dec 2013	10 MMcfd	5.00	10,290	6,441	3,849	-	-	-	-
US	Gas	Swap	Jan 2012-Dec 2013	10 MMcfd	5.00	10,290	6,441	3,849	-	-	-	-
US	Gas	Swap	Jan 2012-Dec 2015	10 MMcfd	6.00	28,510	10,078	7,446	5,970	5,016	-	-
US	Gas	Swap	Jan 2012-Dec 2015	20 MMcfd	6.00	57,018	20,156	14,892	11,940	10,030	-	-
US	Gas	Swap	Jan 2012-Dec 2021	5 MMcfd	6.23	22,331	5,422	4,058	3,289	2,788	2,311	4,463
US	Gas	Swap	Jan 2012-Dec 2021	5 MMcfd	6.20	21,832	5,367	4,005	3,237	2,737	2,261	4,225
US	Gas	Swap	Jan 2012-Dec 2021	5 MMcfd	6.20	21,832	5,367	4,005	3,237	2,737	2,261	4,225
US	NGL	Swap	Jan 2012-Dec 2012	1 MBbld	42.81	(1,733)	(1,733)	-	-	-	-	-
US	NGL	Swap	Jan 2012-Dec 2012	1 MBbld	43.07	(1,639)	(1,639)	-	-	-	-	-
US	NGL	Swap	Jan 2012-Dec 2012	2 MBbld	43.94	(2,639)	(2,639)	-	-	-	-	-
US	NGL	Swap	Jan 2012-Dec 2012	1 MBbld	47.99	161	161	-	-	-	-	-
US	NGL	Swap	Jan 2012-Dec 2012	1 MBbld	46.55	(364)	(364)	-	-	-	-	-
US	NGL	Swap	Jan 2012-Dec 2012	1 MBbld	46.75	(292)	(292)	-	-	-	-	-
			Grand Total			$345,799	$158,817	$65,892	$40,690	$34,324	$15,943	$30,133

During February 2012, we revamped our hedge platform. Through terminations of a portion of our existing natural gas hedge positions, we executed a new series of hedges that accomplish a revised natural gas hedging platform of:

Production Year	Daily Production	Floor	Cap
	Mmbtud		
2012	220	$ 5.78	$ 6.04
2013	150	5.40	5.40
2014 - 2015	110	5.54	5.54

These hedges did not result in the transfer or the receipt of any net cash proceeds. We expect our entire hedge portfolio to continue to qualify for hedge accounting.

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. 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

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 2011, 2010 and 2009, interest expense decreased $4.8 million, $14.0 million and $13.7 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, 2011, each $50 million in borrowings would result in additional annual interest payments of $1.1 million. If the current borrowing availability under our Combined Credit Agreements were to be fully utilized by year-end 2012 at interest rates as of December 31, 2011, we estimate that annual interest payments would increase by $26.1 million. If interest rates change by 1% on our December 31, 2011 variable debt balances of $227.5 million our annual pre-tax income would decrease or increase by $2.3 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. For 2011, 2010 and 2009, non-functional currency transactions resulted in losses of $2.5 million, $0.5 million, and $2.2 million, respectively, included in net earnings. 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 of
Quicksilver Resources Inc.
Fort Worth, Texas

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

As discussed in Note 2 to the consolidated financial statements, on December 31, 2009, the Company adopted Accounting Standards Update No. 2010-3, "Oil and Gas Reserve Estimation and Disclosures."

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated April 15, 2012 expressed an adverse opinion on the effectiveness of the Company's internal control over financial reporting because of a material weakness.

/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, 2011, 2010 AND 2009
In thousands, except for per share data

	2011	2010 [1] (Restated)	2009
Revenue			
Production	$ 800,543	$ 856,349	$ 796,698
Sales of purchased natural gas	86,645	64,089	23,654
Other	56,435	7,893	12,383
Total revenue	943,623	928,331	832,735
Operating expense			
Lease operating	102,874	84,836	79,027
Gathering, processing and transportation	190,560	94,008	48,688
Production and ad valorem taxes	29,226	34,156	23,881
Costs of purchased natural gas	85,398	65,321	30,158
Other operating	557	4,522	6,684
Depletion, depreciation and accretion	225,763	207,203	201,387
Impairment	107,059	47,997	979,540
General and administrative	79,582	80,107	77,243
Total expense	821,019	618,150	1,446,608
Gain on sale of KGS [1]	-	493,953	-
Operating income (loss)	122,604	804,134	(613,873)
Income (loss) from earnings of BBEP	(8,439)	22,323	75,444
Impairment of investment in BBEP	-	-	(102,084)
Other income (expense) - net	219,768	75,724	(1,242)
Interest expense	(186,024)	(188,353)	(195,101)
Income (loss) before income taxes	147,909	713,828	(836,856)
Income tax (expense) benefit	(57,863)	(258,538)	291,617
Net income (loss)	90,046	455,290	(545,239)
Net income attributable to noncontrolling interests	-	(9,724)	(12,234)
Net income (loss) attributable to Quicksilver	$ 90,046	$ 445,566	$ (557,473)
Other comprehensive income (loss)			
Reclassification adjustments related to settlements of derivative contracts - net of income tax	(58,125)	(164,016)	(211,863)
Net change in derivative fair value - net of income tax	156,160	156,850	125,989
Foreign currency translation adjustment	(13,364)	16,017	22,106
Comprehensive income (loss)	$ 174,717	$ 454,417	$ (621,241)
Earnings (loss) per common share - basic	$ 0.53	$ 2.62	$ (3.30)
Earnings (loss) per common share - diluted	$ 0.52	$ 2.50	$ (3.30)

[1] Note 2 contains additional information.

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

QUICKSILVER RESOURCES INC.
CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2011 AND 2010
In thousands, except for share data

	2011	2010 [1] (Restated)
ASSETS		
Current assets		
Cash and cash equivalents	$ 13,146	$ 54,937
Accounts receivable - net of allowance for doubtful accounts	95,282	63,380
Derivative assets at fair value	162,845	89,205
Other current assets	29,154	30,650
Total current assets	300,427	238,172
Investment in equity-method affiliates	-	83,341
Property, plant and equipment - net		
Oil and gas properties, full cost method (including unevaluated costs of $433,341 and $314,543, respectively)	3,226,476	2,840,319
Other property and equipment	234,043	222,926
Property, plant and equipment - net	3,460,519	3,063,245
Assets of midstream operations held for sale	-	27,178
Derivative assets at fair value	183,982	57,557
Other assets	50,534	38,241
	$ 3,995,462	$ 3,507,734
LIABILITIES AND EQUITY		
Current liabilities		
Current portion of long-term debt	$ 18	$ 143,478
Accounts payable	142,672	147,108
Accrued liabilities	142,193	122,904
Derivative liabilities at fair value	4,028	-
Current deferred tax liability	45,262	28,861
Total current liabilities	334,173	442,351
Long-term debt	1,903,431	1,746,716
Liabilities of midstream operations held for sale	-	1,431
Partnership liability	122,913	-
Asset retirement obligations	85,568	56,235
Other liabilities	28,461	28,461
Deferred income taxes	258,997	162,635
Commitments and contingencies (Note 14)		
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 176,980,483 and 175,524,816 shares issued, respectively	1,770	1,755
Additional paid in capital	737,015	714,869
Treasury stock of 5,379,702 and 5,050,450 shares, respectively	(46,351)	(41,487)
Accumulated other comprehensive income	214,858	130,187
Retained earnings	354,627	264,581
Total equity	1,261,919	1,069,905
	$ 3,995,462	$ 3,507,734

[1] Note 2 contains additional information.

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, 2011, 2010 AND 2009
In thousands

	Quicksilver Resources Inc. Stockholders' Equity						
	Common Stock	Additional Paid-in Capital	Treasury Stock	Accumulated Other Comprehensive Income	Retained Earnings [1]	Noncontrolling Interest	Total
Balances at December 31. 2008	1,717	656,958	(35,441)	185,104	376,488	26,737	1,211,563
Net income (loss)	-	-	-	-	(557,473)	12,234	(545,239)
Hedge settlements reclassified into earnings from AOCI, net of income tax of $99,004	-	-	-	(211,863)	-	-	(211,863)
Net change in derivative fair value, net of income tax of $57,007	-	-	-	125,989	-	-	125,989
Foreign currency translation adjustment	-	-	-	22,106	-	-	22,106
Issuance & vesting of stock compensation	22	19,085	(922)	-	-	1,645	19,830
Stock option exercises	6	4,040	-	-	-	-	4,046
Issuance of KGS units	-	50,182	-	-	-	30,133	80,315
Distributions paid on KGS units	-	-	-	-	-	(9,925)	(9,925)
Balances at December 31. 2009	1,745	730,265	(36,363)	121,336	(180,985)	60,824	696,822
Net income [1]	-	-	-	-	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, restated [1]	$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

[1] Note 2 contains additional information.

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, 2011, 2010 AND 2009
In thousands

	2011	2010 [1] (Restated)	2009
Operating activities:			
Net income (loss)	$ 90,046	$ 455,290	$ (545,239)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and accretion	225,763	207,203	201,387
Impairment expense	107,059	47,997	979,540
Deferred income tax expense (benefit)	64,492	185,367	(291,414)
Non-cash (gain) loss from hedging and derivative activities	(51,780)	(58,892)	6,756
Gain on sale of KGS	-	(493,953)	-
Divestiture expenses	-	2,555	-
Stock-based compensation	20,862	25,990	20,815
Non-cash interest expense	16,510	17,226	45,532
Gain on disposition of BBEP units	(217,893)	(57,584)	-
Loss (income) from BBEP in excess of cash distributions	28,269	(1,417)	(64,344)
Impairment of investment in BBEP	-	-	102,084
Other	1,311	(168)	747
Changes in assets and liabilities			
Accounts receivable	(31,803)	(9,501)	77,527
Derivative assets at fair value	-	30,816	54,896
Prepaid expenses and other assets	(6,017)	6,364	3,061
Accounts payable	(11,434)	33,957	(12,320)
Income taxes payable	(4,803)	4,611	60
Accrued and other liabilities	22,471	1,859	33,215
Net cash provided by operating activities	253,053	397,720	612,303
Investing activities:			
Capital expenditures	(690,607)	(695,114)	(693,838)
Proceeds from sale of KGS	-	699,973	-
Proceeds from sale of BBEP units	272,965	34,016	-
Proceeds from sale of properties and equipment	4,163	9,953	220,974
Net cash provided (used) by investing activities	(413,479)	48,828	(472,864)
Financing activities:			
Issuance of debt	855,822	690,058	1,420,727
Repayments of debt	(843,108)	(1,031,736)	(1,649,630)
Debt issuance costs paid	(12,506)	(3,111)	(32,472)
Partnership funds received	122,913	-	-
Gas Purchase Commitment assumed	-	-	58,294
Gas Purchase Commitment repayments	-	(44,119)	(14,175)
Issuance of KGS common units - net offering costs	-	11,054	80,729
Distributions paid on KGS common units	-	(13,550)	(9,925)
Proceeds from exercise of stock options	1,299	1,801	4,046
Excess tax benefits on exercise of stock options	-	3,513	-
Taxes paid on vesting of KGS equity compensation	-	(1,144)	(63)
Purchase of treasury stock	(4,864)	(4,910)	(922)
Net cash provided (used) by financing activities	119,556	(392,144)	(143,391)
Effect of exchange rate changes in cash	(921)	(1,252)	2,889
Net change in cash	(41,791)	53,152	(1,063)
Cash and cash equivalents at beginning of period	54,937	1,785	2,848
Cash and cash equivalents at end of period	$ 13,146	$ 54,937	$ 1,785

[1] Note 2 contains additional information.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 AND 2009

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, 2011, 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
- Steamboat Springs, 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.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Our consolidated financial statements include our accounts and all of our majority-owned subsidiaries and companies over which we exercise control through majority voting rights or other means of control. We eliminate all inter-company balances and transactions in preparing consolidated financial statements. We account for our ownership in unincorporated partnerships and companies, including 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 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 individually 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 other revenue.

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.

We enter into derivatives with counterparties who are our lenders. 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.

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 become publicly available. Consequently, our 2011, 2010 and 2009 annual results of operations include BBEP's earnings for the 12 months ended September 30, 2011, 2010 and 2009. 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 hedge 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.

All 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 comprised of $23.2 million and $25.3 million of materials and parts and $2.3 million and $2.1 million of NGLs as of December 31, 2011 and 2010, respectively. Our materials, parts and supplies inventory is primarily comprised of 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 market, on a first-in, first-out cost basis. "Market," in the context of inventory valuation, 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 transfer 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, 2011 and 2010, 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 our 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.

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."

Immaterial Restatement

The consolidated financial statements as of and for the year ended December 31, 2010 have been restated to increase the previously recognized gain related to the sale of our interests in KGS by $20.7 million and to provide additional deferred taxes on the increased gain. The previously reported gain excluded certain liabilities for intercompany transactions related to services performed by KGS for our U.S. exploration and production segment, which should have been included in the gain calculation. Additional depletion expense was recognized due to the inclusion of additional future development costs in the 2010 depletion calculation. The results of this restatement, which had no impact on our total cash flow from operations, investing and financing activities as reported, were as follows:

Consolidated Statement of Income (Loss) and Comprehensive Income
For the year ended December 31, 2010

	Previously reported	Restated
Gain on sale of KGS	$ 473,204	$ 493,953
Depletion, depreciation and accretion	202,603	207,203
Operating income	787,985	804,134
Income before income taxes	697,679	713,828
Income tax expense	252,886	258,538
Net income	444,793	455,290
Net income attributable to Quicksilver	435,069	445,566
Comprehensive income	443,920	454,417
Earnings per common share - basic	$ 2.56	$ 2.62
Earnings per common share - diluted	$ 2.45	$ 2.50

Consolidated Balance Sheet as of December 31, 2010

	Previously reported	Restated
Oil and gas properties, full cost method	$ 2,844,919	$ 2,840,319
Property, plant and equipment, net	3,067,845	3,063,245
Accounts payable	167,857	147,108
Total current liabilities	463,100	442,351
Deferred income taxes	156,983	162,635
Retained earnings	254,084	264,581
Total equity	1,059,408	1,069,905

In addition to the restatement as described above, we restated amounts within the condensed consolidating financial information which is more fully described in Note 19. The effects of these restatements did not have an effect on retained earnings as of or prior to December 31, 2009.

Variable Interest Entities

An entity is a variable interest entity (VIE) if it meets the criteria outlined in ASC 810, Consolidation (formerly FASB Interpretation No. 46(R)), which are: (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 is the primary beneficiary and for 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 in our consolidated financial statements. The results from operations for Fortune Creek for 2011 were immaterial. Note 16 contains additional discussion regarding the Fortune Creek.

Earnings per Share

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

Recently Issued Accounting Standards

Accounting standard-setting organizations frequently issue new or revised accounting rules. We regularly review all new pronouncements to determine their impact, if any, on our financial statements. No pronouncements materially affecting our financial statements have been issued since the filing of our 2010 Annual Report on Form 10-K.

3. ACQUISITIONS AND DIVESTITURES

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;
  - 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 for third quarter 2010 distributions and after transaction costs. We recognized a gain of $494.0 million. We have the right to collect up to an additional $72 million in future earn-out payments in 2012 and 2013, although we have recognized no assets related to these opportunities. In February 2012, we collected $41 million of these earn-out payments.

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 have not reported 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 Years Ended December 31, 2010	For the Years Ended December 31, 2009
	(In thousands)	
Revenue	$ 13,119	$ 9,342
Lease operating expense	-	-
PGT expense [1]	(57,679)	(74,196)
Ad valorem taxes	3,764	3,610
Other operations	3,444	5,233
DD&A	19,732	24,502
General and administrative expense	5,034	3,229
Impairment expense	28,611	-
Operating results of midstream operations	10,213	46,964
Interest and other expense	(6,916)	(4,764)
Results of midstream operations before income tax	3,297	42,200
Income tax expense	(1,265)	(15,428)
Results of midstream operations, net of income tax	$ 2,032	$ 26,772

(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.

2009 Eni Transaction

In June 2009, we completed the Eni Transaction whereby we entered into a strategic alliance with Eni and sold a 27.5% interest in our Alliance Asset. The assets were sold to Eni for $279.7 million in cash, inclusive of the Gas Purchase Commitment assumed and normal post-closing adjustments. We used the proceeds generated to repay a portion of the Senior Secured Second Lien Facility.

In connection with the sale, we entered into a gas gathering agreement for a pre-set price with Eni covering Eni's production. Under that agreement and subsequent agreements, CMLP will gather, treat and deliver Eni's production. Eni paid $19.2 million to us for construction and installation of the facilities required to gather Eni's production from future Alliance airport area wells. CMLP is now the sole owner of these facilities and is entitled to recognize gathering revenue for the volume of gas that are gathered.

Also as part of the sale, 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, 2011 we had cumulatively completed 137,184 linear feet under the agreement, compared with a contract minimum of 130,743 feet. A total of 191,819 linear feet is required to be completed by December 31, 2013. 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.

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,		Liability Derivatives As of December 31,	
	2011	**2010**	**2011**	**2010**
	(in thousands)		(in thousands)	
Level 2 inputs	$195,838	$146,762	$4,028	$-
Level 3 inputs	150,989	-	-	-
Total	$346,827	$146,762	$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 hedges with an original tenure of 10 years utilize "Level 3" inputs, primarily related to comparatively less market data available for their later term compared with our other shorter term hedges. 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 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, 2011	2010
	(In thousands)	
Balance at beginning of period	$ -	$ -
Total gains for the period:		
Included in OCI	105,137	-
Included in earnings	45,852	-
Balance at end of period	$ 150,989	$ -
Total gains for the period included in earnings attributable to the change in unrealized gains related to assets held at the reporting date	$ 45,852	$ -

Commodity Price Derivatives

As of December 31, 2011, we had price collars and swaps hedging our anticipated natural gas and NGL production as follows:

Production Year	Daily Production Volume Gas	NGL
	MMcfd	MBbld
2012	165	7
2013	105	-
2014-2015	65	-
2016-2021	35	-

On August 31, 2011, we designated our 10-year natural gas swaps as hedges. Unrealized gains of $48.9 million were recognized from the date we entered into them through that date and have been reported in "other revenue." After the designation date, additional unrealized gains and losses, net of hedge ineffectiveness, have been recognized in AOCI until the associated sale of natural gas production occurs. These 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.

Interest Rate Derivatives

In June 2009, we entered into interest rate swaps on our $475 million senior notes due 2015 and our $350 million senior subordinated notes effectively converting the interest on those issues from a fixed to a floating rate indexed to a one-month LIBOR. The maturity dates and all other significant terms were the same as those of the underlying debt. Under these swaps, we paid a variable interest rate and received the fixed rate applicable to the underlying debt. The interest income or expense was accrued as earned and recorded as an adjustment to the interest expense accrued on the fixed-rate debt. The interest rate swaps were designated as fair value hedges of the underlying debt. The value of the contracts, excluding the net interest accrual, amounted to a net asset of $4.1 million and a $4.1 million offsetting fair value adjustment to the debt hedged as of December 31, 2009. No ineffectiveness was recorded in connection with the fair value hedges. The 2010 and 2009 average effective interest rates on the 2015 Senior Notes were 6.5% and 5.1%, respectively. The 2010 and 2009 average effective interest rates on the Senior Subordinated Notes were 5.4% and 3.7%, respectively.

In February 2010, we executed the early settlement of the 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 scheduled as follows:

(In thousands)		
2012	$	5,315
2013		5,769
2014		6,261
2015		4,824
2016		569
	$	22,738

Gas Purchase Commitment

We recognized a liability at the time of the Eni Transaction pursuant to the Gas Purchase Commitment based on the estimated production volume attributable to Eni through December 31, 2010, which then totaled 22.2 Bcf. The Gas Purchase Commitment contained an embedded derivative that was adjusted to fair value throughout the period of the commitment, which expired on December 31, 2010. The following summarizes activity to the Gas Purchase Commitment:

	As of December 31, 2010	
	(in thousands)	
Beginning liability at fair value	$	50,744
Decrease due to gas volumes purchased		(35,057)
Decrease due to changes in gas volumes		(9,062)
Embedded derivative		(6,625)
Ending liability at fair value	$	-

All Derivatives

The estimated fair value of all of our derivatives at December 31, 2011 and 2010 were as follows:

	Asset Derivatives		Liability Derivatives	
	As of December 31,		As of December 31,	
	2011	2010	2011	2010
	(In thousands)		(In thousands)	
Derivatives designated as hedges:				
Commodity contracts reported in:				
Current derivative assets	$ 165,484	$ 97,863	$ 2,639	$ 8,658
Noncurrent derivative assets	183,982	63,419	-	5,862
Current derivative liabilities	-	-	4,028	-
Total derivatives designated as hedges	$ 349,466	$ 161,282	$ 6,667	$ 14,520
Total derivatives	$ 349,466	$ 161,282	$ 6,667	$ 14,520

The increase in carrying value of our commodity price derivatives since December 31, 2010 principally resulted from the overall decline in market prices for natural gas relative to the prices in our open derivative instruments at December 31, 2011 and due to more coverage of future production. These increases were partially offset by monthly settlements received during 2011.

The changes in the carrying value of our derivatives for 2011 and 2010 are presented below:

	For the Years Ended December 31,				
	2011	2010			
	Commodity Derivatives	Gas Purchase Commitment	Fair Value Derivatives	Commodity Derivatives	Total
			(In thousands)		
Derivative fair value at beginning of period	$ 146,762	$ (6,625)	$ 4,108	$ 107,881	$ 105,364
Change in net amounts receivable and payable	(759)	-	(9,180)	(3,451)	(12,631)
Net settlements reported in revenue	(84,046)	-	-	(190,504)	(190,504)
Net settlements reported in interest expense	-	-	(10,848)	-	(10,848)
Cash settlements reported in long-term debt	-	-	(30,816)	-	(30,816)
Unrealized change in fair value of Gas Purchase Commitment reported in costs of purchased gas	-	6,625	-	-	6,625
Change in fair value of effective interest swaps	-	-	46,736	-	46,736
Ineffectiveness reported in other revenue	5,928	-	-	(2,629)	(2,629)
Unrealized gains reported in other revenue	45,852	-	-	-	-
Unrealized gains reported in OCI	229,062	-	-	235,465	235,465
Derivative fair value at end of period	$ 342,799	$ -	$ -	$ 146,762	$ 146,762

Gains and losses from the effective portion of derivative assets and liabilities held in AOCI expected to be reclassified into earnings during 2012 would result in a gain of $86.7 million net of income taxes. Hedge derivative ineffectiveness resulted in net gains of $5.9 million for 2011, and net losses of $2.6 million and $0.1 million for 2010 and 2009, respectively.

5. ACCOUNTS RECEIVABLE

Accounts receivable consisted of the following:

	As of December 31,	
	2011	2010
	(In thousands)	
Accrued production	$ 57,220	$ 36,144
Joint interest billings	7,770	8,172
Income taxes	13,332	17,368
Canadian value added taxes	14,750	-
Other	2,247	1,776
Allowance for doubtful accounts	(37)	(80)
	$ 95,282	$ 63,380

6. OTHER CURRENT ASSETS

Other current assets consisted of the following:

	As of December 31,	
	2011	2010
	(In thousands)	
Inventories	$ 25,503	$ 27,388
Deposits	391	597
Other prepaid expense	3,260	2,665
	$ 29,154	$ 30,650

7. INVESTMENT IN BBEP

At December 31, 2011, we no longer owned any 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 initially received 21.4 million BBEP Units during November 2007 as partial consideration of our oil and gas properties in Michigan, Indiana and Kentucky. On June 17, 2008, BBEP announced that it had repurchased and retired 14.4 million BBEP Units, which represented 22% of the units previously outstanding. The resulting reduction in the number of BBEP Units outstanding increased our ownership at the time from 32% to 41%.

After obtaining our BBEP Units, we evaluated our investment for impairment in response to decreases in both prevailing commodity prices and the BBEP Unit price. We considered numerous factors in evaluating whether this was an other-than-temporary decline. As a result of the period during which BBEP Units traded below our net carrying value per unit, prevailing petroleum prices and broad limitations on available capital resulted in the determination that this was an other-than-temporary decline. Accordingly, the impairment analysis at December 31, 2008 utilized a price of $7.05 per BBEP Unit, or an aggregate fair value of $150.5 million for our investment in BBEP. The estimated fair value of $150.5 million was then compared to our carrying value of $470.9 million. The difference of $320.4 million was recognized as an impairment charge during 2008.

At March 31, 2009, an additional charge for impairment of $102.1 million was recognized as the closing price of $6.53 per BBEP Unit, or an aggregate fair value of $139.4 million, exceeded our carrying value of $241.5 million. No subsequent impairment of our investment has occurred.

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**	**2009**
		(In thousands)	
Revenue (1)	$ 425,386	$ 375,446	$ 609,846
Operating expense (2)	313,388	285,394	380,197
Operating income	111,998	90,052	229,649
Interest and other (3)	40,759	24,903	45,714
Income tax (benefit) expense	1,070	(939)	323
Noncontrolling interests	183	146	27
Net income available to BBEP	$ 69,986	$ 65,942	$ 183,585
Net income available to common unitholders	$ 69,986	$ 65,942	$ 183,585

(1) For the twelve months ended September 30, 2011 and 2009, unrealized gains of $24.0 million and $181.9 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. Realized gains on commodity derivatives of $70.6 million for the early settlement of derivative positions were included for the twelve months ended September 30, 2009.

(2) An impairment of BBEP's oil and gas properties of $86.4 million was included for the twelve months ended September 30, 2009.

(3) The twelve months ended September 30, 2011, 2010 and 2009 included $3.3 million, $5.2 million and $11.1 million, respectively, for unrealized gains on interest rate swaps.

	As of September 30,	
	2011	2010
	(In thousands)	
Current assets	$ 171,850	$ 145,233
Property, plant and equipment	1,765,247	1,728,256
Other assets	104,264	98,113
Current liabilities	85,608	85,035
Long-term debt	511,489	516,000
Other non-current liabilities	55,042	64,715
Partners' equity	1,389,222	1,305,852

Changes in the balance of our investment in BBEP for 2011 and 2010 were as follows:

	As of December 31,	
	2011	2010
	(In thousands)	
Beginning investment balance	$ 83,341	$ 112,763
Income (loss) from earnings in BBEP	(8,439)	22,323
Distributions from BBEP	(19,830)	(20,905)
Disposal of BBEP Units	(55,072)	(30,840)
Ending investment balance	$ -	$ 83,341

8. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consisted of the following:

	As of December 31,	
	2011	2010
	(In thousands)	
Oil and gas properties		
Subject to depletion	$ 5,309,330	$ 4,805,161
Unevaluated costs	433,341	314,543
Accumulated depletion	(2,516,195)	(2,279,385)
Net oil and gas properties	3,226,476	2,840,319
Other property and equipment		
Pipelines and processing facilities	340,242	225,402
General properties	71,297	70,267
Accumulated depreciation	(177,496)	(72,743)
Net other property and equipment	234,043	222,926
Property, plant and equipment, net of accumulated depletion and depreciation	$ 3,460,519	$ 3,063,245

Ceiling Test Analysis and Impairment

The charges for impairment are summarized below:

		Pre-tax Charges for Impairment		
	Segment	2011	2010	2009
			(in thousands)	
U.S.				
Oil and gas properties	Exploration and production	$ -	$ -	$ 786,867
Other property and equipment	Midstream	57,996	28,611	-
Canada				
Oil and gas properties	Exploration and production	49,063	19,386	192,673
		$ 107,059	$ 47,997	$ 979,540

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. The charge for impairment 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 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. We recognized charges for impairment of both our U.S. and Canadian cost centers during 2009 due to significant decreases in natural gas and NGL market prices.

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 2011, we discontinued our efforts to actively market the HCDS assets and re-assumed operating it 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 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 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 is the underlying causes of the impairment. The resulting post-impairment carrying value equaled the discounted fair value of these assets' future cash flows.

Because of the volatility of oil and natural gas prices, it is reasonably possible we may experience additional impairment in future periods.

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, 2011 and 2010 and the year in which they were incurred follows:

	December 31, 2011 Costs Incurred During					December 31, 2010 Costs Incurred During				
	2011	2010	2009	Prior	Total	2010	2009	2008	Prior	Total
	(In thousands)					(In thousands)				
Acquisition costs	$ 119,936	$ 39,307	$ 8,408	$ 126,756	$ 294,407	$ 42,117	$ 7,482	$ 111,929	$ 76,192	$ 237,720
Exploration costs	58,944	31,644	21,389	11,056	123,033	36,383	21,531	7,616	-	65,530
Capitalized interest	6,613	2,769	3,219	3,300	15,901	4,874	2,866	3,553	-	11,293
Total	$ 185,493	$ 73,720	$33,016	$ 141,112	$ 433,341	$ 83,374	$ 31,879	$ 123,098	$ 76,192	$ 314,543

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

	As of December 31,	
	2011	2010
	(In thousands)	
Barnett Shale	$ 68,351	$ 121,854
West Texas	49,750	-
Horn River Basin	180,604	160,663
Sandwash Basin	132,965	30,688
Other	1,671	1,338
Total	$ 433,341	$ 314,543

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 an estimated eight to ten years of exploration and development activity before evaluation is complete.

Other Matters

Capitalized overhead costs that directly relate to exploration and development activities were $18.3 million, $17.7 million and $17.1 million for 2011, 2010 and 2009, respectively. Depletion per Mcfe was $1.35, $1.30 and $1.36 for 2011, 2010 and 2009, respectively. Depreciation expense was $20.3 million, $35.0 million and $37.3 million for 2011, 2010 and 2009, respectively.

9. OTHER ASSETS

Other assets consisted of the following:

	As of December 31,	
	2011	2010
	(In thousands)	
Deferred financing costs	$ 55,952	$ 60,233
Less accumulated amortization	(16,576)	(22,222)
Net deferred financing costs	39,376	38,011
Notes receivable	7,996	-
Other	3,162	230
	$ 50,534	$ 38,241

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,	
	2011	2010
	(In thousands)	
Interest payable	$ 68,091	$ 69,394
Accrued operating expense	46,569	34,136
Prepayments from partners	33	4,490
Revenue payable	26,073	5,563
Accrued state income and franchise taxes	-	4,497
Accrued production and property taxes	815	2,448
Environmental liabilities	63	235
Accrued product purchases	295	345
Current asset retirement obligations	254	1,574
Other	-	222
	$ 142,193	$ 122,904

11. LONG-TERM DEBT

Long-term debt consisted of the following:

	As of December 31, 2011	As of December 31, 2010
	(In thousands)	
2007 Senior Secured Credit Facility	$ -	$ 21,114
Combined Credit Agreements	227,482	-
Senior notes due 2015, net of unamortized discount of $2,980 and $4,134	435,020	470,866
Senior notes due 2016, net of unamortized discount of $13,643 and $16,395	576,977	583,605
Senior notes due 2019, net of unamortized discount of $5,945 and $6,504	292,055	293,496
Senior subordinated notes due 2016	350,000	350,000
Convertible debentures, net of unamortized discount of $0 and $6,522	18	143,478
Total debt	1,881,552	1,862,559
Unamortized deferred gain—terminated interest rate swaps	21,897	27,635
Current portion of long-term debt	(18)	(143,478)
Long-term debt	$ 1,903,431	$ 1,746,716

Maturities are as follows:

	Total Indebtedness	Combined Credit Agreement	Senior Notes due in 2015	Senior Notes due in 2016	Senior Notes due in 2019	Senior Subordinated Notes	Convertible Debentures
				(In thousands)			
2012	$ 18	$ -	$ -	$ -	$ -	$ -	$ 18
2013	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-
2015	438,000	-	438,000	-	-	-	-
2016	1,168,102	227,482	-	590,620	-	350,000	-
Thereafter	298,000	-	-	-	298,000	-	-
	$ 1,904,120	$ 227,482	$ 438,000	$ 590,620	$ 298,000	$ 350,000	$ 18

Credit Facilities

In September 2011, we terminated and replaced our $1.0 billion global 2007 Senior Secured Credit Facility with new separate five-year syndicated senior secured revolving credit facilities for our U.S. and Canadian operations. The $1.25 billion Initial U.S. Credit Facility had a borrowing base of $850 million, including a letter of credit capacity of $75 million, as of September 30, 2011. The C$500 million Initial Canadian Credit Facility had a borrowing base of C$225 million, including a letter of credit capacity of C$100 million, as of September 30, 2011. The borrowing base for each facility was to be re-determined at least semi-annually based upon engineering reports and such other information deemed appropriate by the applicable administrative agent, in a manner consistent with its normal oil and gas lending criteria as it exists at the time of such redetermination.

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 have a global borrowing base of $1.075 billion, including a global letter of credit capacity of $175 million, as of December 31, 2011. 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, without the consent of the lenders.

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, and Quicksilver Resources Partners Operating Ltd. and certain oil and gas properties and related assets of Quicksilver. Borrowings under the Amended and Restated Canadian Credit Facility are guaranteed by Quicksilver and certain of its domestic subsidiaries and are secured by 100% of the equity interests of Quicksilver Resources Canada Inc. and its oil and gas properties and related assets and certain oil and gas properties and related assets of Quicksilver. At December 31, 2011, there was $798.1 million available under the Combined Credit Agreements.

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 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.

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. 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 the Senior Secured Second Lien Facility. 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. 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 2009, 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.

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 are contingently convertible into shares of our common stock. The debentures bear interest at an annual rate of 1.875% payable semi-annually on May 1 and November 1. Additionally, holders of the debentures can require us to repurchase all or a portion of their debentures on November 1, 2011, 2014 and 2019 at a price equal to the principal amount thereof plus accrued and unpaid interest. The debentures are convertible into shares of our common stock at a rate of 65.4418 shares for each $1,000 debenture, subject to adjustment. Generally, except upon the occurrence of specified events including certain changes of control, holders of the debentures are not entitled to exercise their conversion rights unless the closing price of our stock is at least $18.34 (120% of the conversion price per share) for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter. Upon conversion, we have the option to deliver any combination of our common stock and cash. Should all debentures be converted to our common stock, an additional 9,816,270 shares, subject to adjustment, would become outstanding; however, as of January 1, 2011, the debentures were not convertible based on share prices for the quarter ended December 31, 2010. We reported these obligations as current obligations in our December 31, 2010 balance sheet.

On November 1, 2011, we repurchased substantially all of the debentures for $150.0 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.

At December 31, 2010, the remaining unamortized discount on the debentures was $6.5 million, resulting in a carrying value of $143.5 million. The remaining discount was accreted to face value through October 2011. 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.

Summary of All Outstanding Debt

As of December 31, 2011, the following subsidiaries are guarantors under our debt obligations: Cowtown Pipeline Management, Inc., Cowtown Pipeline Funding, Inc., Cowtown Gas Processing L.P., Cowtown Pipeline L.P., and Barnett Shale Operating LLC. The following table summarizes other significant aspects of our long-term debt outstanding at December 31, 2011:

	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	$1.075 billion (2)	$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, 2011 (3)	2.13%	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 - Minimum EBITDA to cash interest expense ratio of 2.5	N/A	N/A	N/A	N/A
Significant restrictive covenants (6)	- Incurrence of debt - Incurrence of liens - Payment of dividends - Equity purchases - Asset sales - Affiliate transactions - Limitations on derivatives	- Incurrence of debt - Incurrence of liens - Payment of dividends - Equity purchases - Asset sales - Affiliate transactions	- Incurrence of debt - Incurrence of liens - Payment of dividends - Equity purchases - Asset sales - Affiliate transactions	- Incurrence of debt - Incurrence of liens - Payment of dividends - Equity purchases - Asset sales - Affiliate transactions	- Incurrence of debt - Incurrence of liens - Payment of dividends - Equity purchases - Asset sales - Affiliate transactions
Optional redemption (6)	Any time	August 1, 2012: 103.875 2013: 101.938 2014: par	July 1, 2013: 105.875 2014: 102.938 2015: par	August 15, 2014: 104.563 2015: 103.042 2016: 101.521 2017: par	April 1, 2012: 102.375 2013: 101.188 2014: par
Make-whole redemption (6)	N/A	Callable prior to August 1, 2012 at make-whole call price of Treasury + 50 bps	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
Equity clawback (6)	N/A	N/A	Redeemable until July 1, 2012 at 111.75%, plus accrued interest for up to 35%	Redeemable until August 15, 2012 at 109.125%, plus accrued interest for up to 35%	N/A
Estimated fair value (7)	$227.5 million	$446.7 million	$669.7 million	$314.4 million	$346.5 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, and Quicksilver Resources Partners Operating Ltd., and certain oil and gas properties and related assets of Quicksilver. Borrowings under the Amended and Restated Canadian Credit Facility are guaranteed by Quicksilver and certain of its domestic subsidiaries and are secured by 100% of the equity interests of Quicksilver Resources Canada Inc. and its oil and gas properties and related assets, and certain oil and gas properties and related assets of Quicksilver. 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, 2011.

(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 credit agreement) plus an applicable margin between 1.50% to 2.50%, (ii) ABR (as defined in the credit agreement), which is the greatest of (a) the prime rate announced by JPMorgan, (b) the federal funds rate plus 0.50% and (c) adjusted LIBOR (as defined in the credit agreement) plus 1.0%, plus, in each case under scenario (ii), an applicable margin between 0.50% to 1.50%. We also pay a per annum fee on all letters of credit issued under the Amended and

Restated U.S. Credit Facility equal to the applicable margin and a commitment fee on the unused availability under the Amended and Restated U.S. Credit Facility of 0.375% to 0.50%, in each case, based on global borrowing base usage.

(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 credit agreement) plus an applicable margin between 1.50% and 2.50%, (ii) the Canadian Prime Rate (as defined in the credit agreement) plus an applicable margin between 0.50% and 1.50%, (iii) the U.S. Prime Rate (as defined in the credit agreement) plus an applicable margin between 0.50% and 1.50% and (iv) eurodollar loans (as defined in the credit agreement) plus an applicable margin between 1.50% to 2.50%. We pay a per annum fee on all letters of credit issued under the Amended and Restated Canadian Credit Facility equal to the applicable margin and a commitment fee on the unused availability under the Amended and Restated Canadian Credit Facility of 0.375% to 0.50%, in each case, based on global borrowing base usage.

(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 based on market quotations on the balance sheet date for fixed rate obligations. We consider debt with variable interest rates to have a fair value equal to its carrying value.

12. ASSET RETIREMENT OBLIGATIONS

The following table provides a reconciliation of the changes in the estimated asset retirement obligation from January 1, 2010 through December 31, 2011.

	As of December 31,	
	2011	2010
	(In thousands)	
Beginning asset retirement obligations	$ 57,809	$ 48,581
Additional liability incurred	6,134	2,440
Change in estimates	20,573	2,042
Accretion expense	2,696	2,568
Asset retirement costs incurred	(2,857)	(1,184)
Gain on settlement of liability	816	1,264
Reclassification of liability of operations previously held for sale	1,431	-
Currency translation adjustment	(780)	2,098
Ending asset retirement obligations	85,822	57,809
Less current portion	(254)	(1,574)
Long-term asset retirement obligation	$ 85,568	$ 56,235

13. INCOME TAXES

Significant components of our deferred tax assets and liabilities as of December 31, 2011 and 2010 are as follows:

	As of December 31,	
	2011	2010 [(1)]
	(In thousands)	
Deferred tax assets:		
Net operating loss carry-forwards	$ 136,492	$ 98,870
Investment in Fortune Creek	3,681	-
AMT tax credit	62,067	67,633
Settlements of interest rate swaps	7,664	9,672
Deferred compensation expense	17,865	8,401
Other	589	7,028
Less: Valuation allowance — Fortune Creek	(3,681)	-
Deferred tax assets	224,677	191,604
Deferred tax liabilities:		
Property, plant and equipment	(420,564)	(297,798)
Gains from hedging and derivative activities	(95,373)	(49,153)
Unrealized gains reported in earnings	(12,999)	-
Investment in BBEP	-	(16,545)
Convertible debentures	-	(19,604)
Deferred tax liabilities	(528,936)	(383,100)
Total deferred tax asset (liability)	$ (304,259)	$ (191,496)
Reflected in the consolidated balance sheets as:		
Non-current deferred income tax asset	$ -	$ -
Current deferred income tax liability	(45,262)	(28,861)
Non-current deferred income tax liability	(258,997)	(162,635)
	$ (304,259)	$ (191,496)

(1) Note 2 contains additional information regarding restated 2010 amounts.

The components of net income (loss) before income tax for 2011, 2010 and 2009 are as follows:

	2011	2010	2009
		(In thousands)	
U.S.	$ 146,090	$ 708,081	$ (744,053)
Canada	1,819	5,747	(92,803)
Total	$ 147,909	$ 713,828	$ (836,856)

No rate changes occurred in any taxing jurisdiction for 2009, 2010 or 2011. For 2012 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 2011, 2010 and 2009 are as follows:

	2011	2010 (1)	2009
		(In thousands)	
Current state income tax expense (benefit)	$ (1,706)	$ 4,501	$ (2)
Current U.S. federal income tax expense (benefit)	(5,565)	67,632	(202)
Current Canadian income tax expense	642	1,038	-
Total current income tax expense (benefit)	(6,629)	73,171	(204)
Deferred state income tax expense (benefit)	1,980	3,674	(4,928)
Deferred U.S. federal income tax expense (benefit)	58,890	179,400	(262,217)
Deferred Canadian income tax expense (benefit)	3,622	2,293	(24,268)
Total deferred income tax expense (benefit)	64,492	185,367	(291,413)
Total income tax expense (benefit)	$57,863	$ 258,538	$ (291,617)

(1) Note 2 contains additional information regarding restated 2010 amounts.

The following table reconciles the statutory federal income tax rate to the effective tax rate for 2011, 2010 and 2009:

	2011	2010 (1)	2009
U.S. federal statutory tax rate	35.00%	35.00%	35.00%
Permanent differences	1.51%	0.78%	(0.18%)
Noncontrolling interest benefit (expense)	0.00%	(0.48%)	0.71%
State income taxes net of federal deduction	0.12%	0.74%	0.38%
Canadian income taxes	2.41%	0.18%	(0.98%)
Other	0.08%	0.00%	(0.08%)
Effective income tax rate	39.12%	36.22%	34.85%

(1) Note 2 to contains additional information regarding restated 2010 amounts.

We incurred net operating tax losses of $35 million, $336 million and $656 million in 2011, 2009 and 2008, respectively, of which $138 million was carried back to 2007. Approximately $476 million of the remaining $889 million has been applied to our 2010 taxable income and the remainder is included in deferred tax assets at December 31, 2011. Our net operating losses will expire between 2029 and 2032. In December 2009, newly enacted federal legislation allowed us to carry back 2008 alternative minimum tax losses of $35 million to 2004 and 2007. The net operating losses have not been reduced by a valuation allowance, because we believe that future taxable income would more likely than not be sufficient to utilize substantially all of our operating loss tax carry-forwards prior to their expiration.

QRI's tax basis in the Fortune Creek Partnership exceeds book basis by $29 million. The Company expects 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, we have 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. We remain subject to examination by the IRS for the years 2001 through 2006 except for 2004. An audit was completed by the IRS for 2004 and the statute of limitations has now expired for that year.

The following schedule reconciles the total amounts of unrecognized tax benefits for 2011 and 2010:

	As of December 31,	
	2011	2010
	(In thousands)	
Beginning unrecognized tax benefits	$ 9,219	$ 9,219
Changes	-	-
Ending unrecognized tax benefits	$ 9,219	$ 9,219

At December 31, 2011, $9.0 million of these unrecognized tax benefits, if recognized, would impact the effective tax rate.

14. COMMITMENTS AND CONTINGENCIES

Contractual Obligations

Information regarding our contractual obligations, at December 31, 2011, is set forth in the following table:

	GPT Contracts (1)	Drilling Rig Contracts (2)	Operating Leases (3)	Purchase Obligations (4)
	(In thousands)			
2012	$ 67,341	$ 23,948	$ 5,484	$ 11,355
2013	82,807	806	4,715	-
2014	111,894	-	4,478	-
2015	143,095	-	4,158	-
2016	147,692	-	3,285	-
Thereafter	477,583	-	18,627	-
Total	$ 1,030,412	$ 24,754	$ 40,747	$ 11,355

(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 $12,500 to $27,005 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 $4.8 million in 2011, $4.3 million in 2010 and $4.1 million in 2009.

(4) At December 31, 2011, 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 NGTL 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 expected to continue through 2014. Assuming the project is fully constructed and based on estimated costs of C$257.4 million, including taxes of C$27.6 million, we expect to provide cumulative letters of credit as follows:

	NGTL Cumulative Financial Assurances [1]	
	(C$ in thousands)	(US$ in thousands)
July 1, 2012	$ 68,264	$ 67,124
October 1, 2012	109,816	$ 107,982
July 1, 2013	148,400	$ 145,922
October 1, 2013	257,400	$ 253,101

(1) A letter of credit for C$32.6 million is outstanding for the NGTL Project as of December 31, 2011.

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 National Energy Board of Canada. Based on this and on numerous other factors, we consider the likelihood to be remote that NGTL will terminate the project. Accordingly, no amounts have been recognized on our consolidated balance sheet as of December 31, 2011. Upon completion of the project, all construction-related guarantees will expire.

We have 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, 2011, we had $9.1 million in surety bonds issued to fulfill contractual, legal or regulatory requirements and $49.4 million in letters of credit outstanding against the credit facility. Surety bonds and letters of credit generally have an annual renewal option.

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.

The allegations against our Executive Vice President – Operations in the District Court of Cleveland County, Oklahoma were dismissed on January 17, 2012.

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, 2011, we had recorded $0.1 million for liabilities for environmental matters.

15. NONCONTROLLING INTERESTS AND KGS

KGS issued 4,000,000 newly issued 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 newly issued 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 the 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 to form a midstream partnership, Fortune Creek, dedicated to the construction and operation of midstream assets to support natural gas producers 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 connection with the partnership formation, we contributed an existing 20-mile, 20-inch gathering line, its related compression facilities, and 10-year contracts dedicating our future gas production from our Horn River Asset, as more fully described below. KKR contributed $125 million cash in exchange for a 50% interest in the partnership. Our Canadian subsidiary has responsibility of 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 all of the capital contributions associated with the development of the 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.

Based on an analysis of the entities 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 facilities, we have determined we are the primary beneficiary and therefore, we consolidate Fortune Creek.

The following December 31, 2011 balances related to Fortune Creek are recorded in our consolidated balance sheet:

(In thousands)		
Cash and cash equivalents	$	12,783
Canadian value-added tax receivable		14,750
Property, plant and equipment, net		80,761
Total assets	$	108,294
Partnership liability	$	122,913
Asset retirement obligations		80
Total liabilities	$	122,993

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, 2011, we had 171.6 million shares of common stock outstanding.

The following table shows common share and treasury share activity since January 1, 2009:

	Common Shares Issued	Treasury Shares Held
Balance at January 1, 2009	171,742,699	4,572,795
Stock options exercised	610,000	-
Restricted stock activity	2,117,137	131,653
Balance at December 31, 2009	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

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. 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 $90, after adjustments to reflect the two-for-one stock split in January 2008.

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 common stock. This 15% threshold does not apply to certain members of the Darden family and affiliated entities, which collectively owned, directly or indirectly, approximately 30% of our common stock at February 15, 2012.

If an Acquiring Person acquires 15% or more of our outstanding common stock, each right 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, each right 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, the rights are redeemable for $0.01 per right at the option of our Board of Directors.

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, 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 10 years from the date of grant. At December 31, 2011 and 2010, 12.6 million shares and 14.1 million shares (including 0.9 million shares and 0.6 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:

	2011	2010	2009
Weighted average grant date fair value	$9.16	$ 9.88	$3.36
Weighted average grant date	Jan 3, 2011	Jan 4, 2010	Jan 2, 2009
Weighted average risk-free interest rate	2.38%	3.00%	1.90%
Expected life (in years)	6.0	6.0	6.0
Weighted average volatility	66.77%	66.76%	56.76%
Expected dividends	-	-	-

The following table summarizes our stock option activity for 2011:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Intrinsic Value
			(In years)	(In thousands)
Outstanding at January 1, 2011	3,348,642	$ 11.10		
Granted	834,970	14.88		
Exercised	(209,221)	6.21		
Cancelled	(150,231)	10.78		
Expired	(63,464)	23.62		
Outstanding at December 31, 2011	3,760,696	$ 12.01	7.5	$ 922
Exercisable at December 31, 2011	1,815,782	$ 11.79	6.8	$ 597

We estimate that a total of 3.7 million stock options will become vested including those options already exercisable. The unexercised options have a weighted average exercise price of $12.03 and a weighted average remaining contractual life of 7.5 years.

Compensation expense related to stock options of $7.0 million, $6.7 million and $4.5 million was recognized for 2011, 2010 and 2009, respectively. The total intrinsic value of options exercised during 2011, 2010 and 2009, was $1.2 million, $2.8 million and $4.3 million, respectively.

Restricted Stock and Stock Units

The following table summarizes our restricted stock and stock unit activity for 2011:

	Payable in shares		Payable in cash	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2011	2,329,089	$ 11.27	372,633	$ 10.31
Granted	1,389,404	13.89	214,515	14.88
Vested	(1,115,235)	12.17	(154,505)	9.88
Cancelled	(142,958)	12.23	(62,797)	13.19
Outstanding at December 31, 2011	2,460,300	$ 12.29	369,846	$ 13.12

At December 31, 2010, we had unrecognized compensation cost related to outstanding unvested restricted stock and RSUs of $13.9 million. As of December 31, 2011, the unrecognized compensation cost related to outstanding unvested restricted stock and RSUs was $17.3 million, which is expected to be recognized in expense over the next 2 years. Grants of restricted stock and RSUs during 2011 had an estimated grant date fair value of $19.3 million. The fair value of RSUs settled in cash was $2.5 million and $5.5 million at December 31, 2011 and 2010, respectively. For 2011, 2010 and 2009, compensation expense of $13.9 million, $13.3 million and $14.6 million, respectively, was recognized. The total fair value of shares vested during 2011, 2010 and 2009 was $13.6 million, $16.4 million and $11.0 million, respectively.

Accumulated Other Comprehensive Income

At December 31, 2011, AOCI included $195.2 million and $19.7 million for derivatives and foreign currency translation, respectively. At December 31, 2010, AOCI included $97.2 million and $33.0 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,		
	2011	2010 (3)	2009
	(In thousands, except per share data)		
Net income (loss) attributable to Quicksilver	$ 90,046	$ 445,566	$ (557,473)
Basic income allocable to participating securities (1)	(1,106)	(5,698)	-
Basic net income (loss) attributable to Quicksilver	$ 88,940	$ 439,868	$ (557,473)
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	$ 88,940	$ 447,062	$ (557,473)
Weighted average common shares — basic	168,993	168,010	169,004
Effect of dilutive securities (2):			
Share-based compensation awards	742	802	-
Convertible debentures	-	9,816	-
Weighted average common shares — diluted	169,735	178,628	169,004
Earnings (loss) per common share — basic	$ 0.53	$ 2.62	$ (3.30)
Earnings (loss) per common share — diluted	$ 0.52	$ 2.50	$ (3.30)

(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 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. For 2009, the effects of 9.8 million shares associated with our contingently convertible debt and all share-based compensation awards were antidilutive and, therefore, excluded from the diluted share calculations.

(3) Note 2 contains additional information regarding restated 2010 amounts.

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.		Quicksilver Gas Services Operating LLC [2]
Barnett Shale Operating LLC [3]		Quicksilver Gas Services Operating GP LLC [2]
		Cowtown Pipeline Partners L.P. [2]
		Cowtown Gas Processing Partners L.P. [2]
		Makarios Midstream Inc. [3]
		1622834 Alberta Inc. [3]
		Makarios Resources International Holdings LLC [3]
		Makarios Resources International Inc. [3]
		Quicksilver Resources GP LLC [3]
		Quicksilver Production Partners LP [3]

(1) This entity was inactive for the three-year period ended December 31, 2011.

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

(3) These entities were created in 2011.

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. Neither the restricted non-guarantor subsidiaries nor the unrestricted non-guarantor subsidiaries guarantee the obligations under the senior notes and 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 2011, 2010 and 2009 condensed consolidating financial information includes changes in the financial information of our unrestricted non-guarantor subsidiaries to present the 2011, 2010 and 2009 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.

Immaterial Restatement of Condensed Consolidating Financial Information

We have restated 2010 results of operation and financial condition related to the gain on sale of our interests in KGS, which is more fully described in Note 2. This restatement impacted the "Quicksilver Resources Inc." column.

In addition, we restated 2010 results of operation and financial condition to reclassify an $85.0 million intercompany payable previously recorded in current assets to current liabilities within the "Quicksilver Resources Inc." column. We also restated to reclassify a $243.6 million intercompany receivable and payable previously reported as Investment in subsidiaries to Other Assets in the "Quicksilver Resources Inc." column and to Long-term liabilities in the "Restricted Non-Guarantor Subsidiaries" column. These restatements had no impact on the totals reported for the "Quicksilver and Restricted Subsidiaries" for 2010 results of operation and financial condition.

Condensed Consolidating Balance Sheets

	December 31, 2011								
	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
	(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

	December 31, 2010 (Restated)							
	Quicksilver Resources Inc.	Restricted Guarantor Subsidiaries	Restricted Non-Guarantor Subsidiaries	Restricted Subsidiary Eliminations	Quicksilver and Restricted Subsidiaries	Unrestricted Non-Guarantor Subsidiaries	Consolidating Eliminations	Quicksilver Resources Inc. Consolidated
	(In thousands)							
ASSETS								
Current assets	$ 295,697	$ 86,582	$ 49,424	$(193,531)	$ 238,172	$ -	$ -	$ 238,172
Property and equipment	2,413,080	68,390	581,775	-	3,063,245	-	-	3,063,245
Assets of midstream operations	-	27,178	-	-	27,178	-	-	27,178
Investment in subsidiaries (equity method)	367,845	-	-	(284,504)	83,341	-	-	83,341
Other assets	339,227	-	191	(243,620)	95,798	-	-	95,798
Total assets	$ 3,415,849	$ 182,150	$ 631,390	$(721,655)	$ 3,507,734	$ -	$ -	$ 3,507,734
LIABILITIES AND EQUITY								
Current liabilities	$ 475,882	$ 106,627	$ 53,373	$(193,531)	$ 442,351	$ -	$ -	$ 442,351
Long-term liabilities	1,870,062	20,346	347,259	(243,620)	1,994,047	-	-	1,994,047
Liabilities of midstream operations	-	1,431	-	-	1,431	-	-	1,431
Quicksilver stockholders' equity	1,069,905	53,746	230,758	(284,504)	1,069,905	-	-	1,069,905
Total liabilities and equity	$ 3,415,849	$ 182,150	$ 631,390	$ (721,655)	$ 3,507,734	$ -	$ -	$ 3,507,734

Condensed Consolidating Statements of Income

	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

	For the Year Ended December 31, 2010 (Restated)							
	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

	For the Year Ended December 31, 2009							
	Quicksilver Resources Inc.	Restricted Guarantor Subsidiaries	Restricted Non-Guarantor Subsidiaries	Restricted Subsidiary Eliminations	Quicksilver and Restricted Subsidiaries	Unrestricted Non-Guarantor Subsidiaries	Consolidated Eliminations	Quicksilver Resources Inc. Consolidated
				(In thousands)				
Revenue	$ 634,321	$ 4,395	$188,769	$ (2,014)	$ 825,471	$ 91,706	$(84,442)	$ 832,735
Operating expenses	1,202,124	9,413	273,969	(2,014)	1,483,492	47,610	(84,494)	1,446,608
Equity in net earnings of subsidiaries	(52,643)	27,161	-	52,643	27,161	-	(27,161)	-
Operating income (loss)	(620,446)	22,143	(85,200)	52,643	(630,860)	44,096	(27,109)	(613,873)
Income from earnings of BBEP	75,444	-	-	-	75,444	-	-	75,444
Impairment of investment in BBEP	(102,084)	-	-	-	(102,084)	-	-	(102,084)
Interest expense and other	(180,980)	3,725	(8,526)	-	(185,781)	(8,518)	(2,044)	(196,343)
Income tax (expense) benefit	270,593	(9,054)	24,269	-	285,808	5,809	-	291,617
Discontinued operations	-	-	-	-	-	(1,992)	1,992	-
Net income (loss)	$ (557,473)	$16,814	$ (69,457)	$52,643	$ (557,473)	$ 39,395	$(27,161)	$ (545,239)
Net income attributable to noncontrolling interests	-	-	-	-	-	(12,234)	-	(12,234)
Net income (loss) attributable to Quicksilver	$ (557,473)	$16,814	$ (69,457)	$52,643	$ (557,473)	$ 27,161	$(27,161)	$ (557,473)

Condensed Consolidating Statements of Cash Flows

	For the Year Ended December 31, 2011							
	Quicksilver Resources Inc.	Restricted Guarantor Subsidiaries	Restricted Non-Guarantor Subsidiaries	Restricted Subsidiary Eliminations	Quicksilver and Restricted Subsidiaries	Fortune Creek	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 (Restated)							
	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

	For the Year Ended December 31, 2009							
	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 operating activities	$ 358,405	$ 73,202	$ 148,280	$ -	$ 579,887	$ 68,133	$ (35,717)	$ 612,303
Capital expenditures	(474,659)	(73,202)	(94,209)	-	(642,070)	(54,818)	3,050	(693,838)
Proceeds from sale of properties and equipment	220,206	-	768	-	220,974	-	-	220,974
Net cash flow used for investing activities	(254,453)	(73,202)	(93,441)	-	(421,096)	(54,818)	3,050	(472,864)
Issuance of debt	1,305,137	-	59,590	-	1,364,727	56,000	-	1,420,727
Repayments of debt	(1,428,105)	-	(116,025)	-	(1,544,130)	(105,500)	-	(1,649,630)
Debt issuance costs	(29,901)	-	(1,125)	-	(31,026)	(1,446)	-	(32,472)
Repayments to parent	-	-	-	-	-	(5,645)	5,645	-
Gas Purchase Commitment—net	44,119	-	-	-	44,119	-	-	44,119
Issuance of KGS common units	-	-	-	-	-	80,729	-	80,729
Distributions to parent	-	-		-	-	(27,022)	27,022	-
Distributions to noncontrolling interests	-	-	-	-	-	(9,925)	-	(9,925)
Proceeds from exercise of stock options	4,046	-	-	-	4,046	-	-	4,046
Taxes paid on vested KGS equity compensation	-	-	-	-	-	(63)	-	(63)
Purchase of treasury stock	(922)	-	-	-	(922)	-	-	(922)
Net cash flow provided by (used for) financing activities	(105,626)	-	(57,560)	-	(163,186)	(12,872)	32,667	(143,391)
Effect of exchange rates on cash	-	-	2,889	-	2,889	-	-	2,889
Net decrease in cash and equivalents	(1,674)	-	168	-	(1,506)	443	-	(1,063)
Cash and equivalents at beginning of period	1,679	-	866	-	2,545	303	-	2,848
Cash and equivalents at end of period	$ 5	$ -	$ 1,034	$ -	$ 1,039	$ 746	$ -	$ 1,785

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, prior to the Crestwood Transaction, we operated in the midstream segment in the U.S., where we provided natural gas gathering and processing services predominantly through KGS. Following our announced partnership with KKR, we expect to have a midstream segment in Canada beginning in 2012 conducted through Fortune Creek. Revenue earned by KGS prior to the Crestwood Transaction for the gathering and processing of our gas has been eliminated on a consolidated basis as is the GPT recognized by our producing properties. We evaluate performance based on operating income and property and equipment costs incurred.

	Exploration & Production					Quicksilver
	U.S.	Canada	Midstream	Corporate	Elimination	Consolidated
			(In thousands)			
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 [1]	136,361	45,335	23,523	1,984	-	207,203
Impairment expense	-	19,386	28,611	-	-	47,997
Operating income (loss) [1]	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
2009						
Revenue	$ 634,321	$ 188,770	$ 99,817	$ -	$(90,173)	$ 832,735
DD&A	134,066	38,965	26,682	1,674	-	201,387
Impairment expense	786,867	192,673	-	-	-	979,540
Operating income (loss)	(500,164)	(81,529)	46,737	(78,917)	-	(613,873)
Property and equipment costs incurred	391,916	91,949	115,655	2,161	-	601,681
Property, plant and equipment—net						
December 31, 2011	$ 2,752,101	$ 677,695	$ 21,477	$ 9,246	$ -	$ 3,460,519
December 31, 2010 [1]	2,398,439	581,775	68,389	14,642	-	3,063,245
December 31, 2009	1,968,430	491,528	71,264	11,623	-	2,542,845
Investment in equity affiliates						
December 31, 2011	$ -	$ -	$ -	$ -	$ -	$ -
December 31, 2010	83,341	-	-	-	-	83,341
December 31, 2009	112,763	-	-	-	-	112,763

(1) Note 2 contains additional information regarding restated 2010 amounts.

21. SUPPLEMENTAL CASH FLOW INFORMATION

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

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Interest, net of capitalized interest	$ 170,814	$ 136,459	$ 128,217
Income taxes	(4,249)	78,083	(41,267)

Other significant non-cash transactions are as follows:

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Working capital related to capital expenditures	$ 107,586	$ 100,587	$ 118,294
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, $2.5 million and $2.3 million for 2011, 2010 and 2009, 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 2011, 2010 and 2009 was $0.8 million for each year.

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 2011, 2010 and 2009 we recognized expense of $4.8 million, $3.5 million and $4.6 million, respectively, for this plan.

23. TRANSACTIONS WITH RELATED PARTIES

As of February 15, 2012, 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 $0.2 million in 2011, $0.6 million in 2010, and $0.7 million in 2009 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 October 2011, we agreed to purchase 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 2011, 2010 and 2009, we paid $0.9 million, $0.8 million and $0.2 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.

We paid $0.2 million in 2009 primarily for delay rentals under leases for over 5,000 acres held by a related entity. The lease terms were determined based on comparable prices and terms granted to third parties with respect to similar leases in the area. No payments were made in 2011 or 2010.

Payments received in 2011, 2010 and 2009 from Mercury for sublease rentals, employee insurance coverage and administrative services were $0.1 million, $0.3 million, and $0.3 million, respectively.

An entity affiliated with Mercury 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)			
2011 (1) (5)				
Operating revenue	$ 212,187	$ 248,446	$ 259,893	$ 223,097
Operating income	(793)	78,676	67,981	(23,260)
Net income	(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
2010 (2) (3) (4)				
Operating revenue	$ 222,158	$ 228,570	$ 237,700	$ 239,903
Operating income	75,845	108,867	65,092	554,330
Net income	10,600	90,744	26,569	327,377
Net income attributable to Quicksilver	8,188	86,803	21,803	328,772
Basic net earnings per share	$ 0.05	$ 0.51	$ 0.13	$ 1.93
Diluted net earnings per share	0.05	0.49	0.13	1.80

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

(2) Operating income for the third quarter of 2010 includes a charge of $28.6 million for impairment of the HDCS to net realizable value.

(3) Operating income for the fourth quarter of 2010 includes a gain on sale of $494.0 million for the sale of all of our interests in KGS and a charge of $19.4 million for the impairment of our Canadian oil and gas properties.

(4) Note 2 to the consolidated financial statements contains additional information regarding restated 2010 amounts. Given the sale of our interests in KGS occurred in October 2010, only the fourth quarter of 2010 was affected.

(5) Operating income 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.

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 Data and Consulting Services 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 2011, 2010 and 2009 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 without any. 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 and 2009 because we account for BBEP by the equity method.

Consolidated Quicksilver (Excluding BBEP Reserves)

The changes in our proved reserves for the three years ended December 31, 2011 were as follows:

	Natural Gas (MMcf)			NGL (MBbl)			Oil (MBbl)		
	U.S.	Canada	Total	U.S.	Canada	Total	U.S.	Canada	Total
December 31, 2008	1,306,497	332,571	1,639,068	91,927	8	91,935	2,914	-	2,914
Revisions (4)	(28,833)	(67,207)	(96,040)	(4,178)	7	(4,171)	205	1	206
Extensions and discoveries (3)	460,214	12,153	472,367	15,487	-	15,487	165	-	165
Purchases in place	314	-	314	-	-	-	-	-	-
Sales in place (2)	(120,539)	(44)	(120,583)	-	-	-	-	-	-
Production	(61,619)	(24,420)	(86,039)	(4,975)	(2)	(4,977)	(425)	(1)	(426)
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
Proved developed reserves									
December 31, 2009	1,044,140	223,300	1,267,440	60,997	13	61,010	2,467	-	2,467
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
Proved undeveloped reserves									
December 31, 2009	511,894	29,753	541,647	37,264	-	37,264	392	-	392
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

(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, respectively. 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 2009 relate principally to the Eni Transaction, which is more fully described in Note 3 to our consolidated financial statements.

(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:

- 2011 are 100% attributable to our Barnett Shale Asset (of which 11% were proved developed);

- 2010 are 100% attributable to our Barnett Shale Asset (of which 40% were proved developed);
- 2009 are 99% attributable to our Barnett Shale Asset (of which 42% were proved developed); and

Canadian extensions and discoveries for:

- 2011 are 97% attributable to our Horn River Asset and 3% are attributable to our Horseshoe Canyon Asset;
- 2010 are 69% attributable to our Horn River Asset and 31% are attributable to our Horseshoe Canyon Asset,
- 2009 are 53% attributable to our Horn River Asset and 47% are attributable to our Horseshoe Canyon Asset.

(4) Revisions for each period presented reflect upward (downward) changes in previous estimates attributable to changes in operating and development costs, new information gained primarily from development drilling activity and production history and changes to development plans. Revisions include (154,405) MMcfe, (73,096) MMcfe and 132,846 MMcfe for such matters in 2011, 2010 and 2009, respectively. Revisions also include (54,539) MMcfe, 117,975 MMcfe and (251,676) MMcfe for changes in economic factors in 2011, 2010 and 2009. In 2011, negative revisions not related to economic factors resulted from removing proved undeveloped reserves that had not been developed within five years (55 Bcfe), change in performance related to offsetting activities, higher pipeline pressures and other factors (85 Bcfe) and various operational issues (14 Bcfe).

The carrying value of our oil and gas assets as of December 31, 2011, 2010 and 2009 were as follows:

	U.S.	Canada	Consolidated
		(In thousands)	
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	$ 2,268,224	$ 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
2009			
Proved properties	$ 3,218,796	$ 728,880	$ 3,947,676
Unevaluated properties	340,707	117,330	458,037
Accumulated DD&A	(1,670,923)	(396,546)	(2,067,469)
Net capitalized costs	$ 1,888,580	$ 449,664	$ 2,338,244

Our consolidated capital costs incurred for acquisition, exploration and development activities during each of the three years ended December 31, 2011, were as follows:

	U.S.	Canada	Consolidated
		(In thousands)	
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
2009			
Proved acreage	$ 118	$ -	$ 118
Unproved acreage	11,300	2,658	13,958
Development costs	341,658	24,179	365,837
Exploration costs	32,798	59,402	92,200
Total	$ 385,874	$ 86,239	$ 472,113

Consolidated results of operations from our producing activities for each of the three years ended December 31, 2011, are set forth below:

	U.S.	Canada	Consolidated
		(In thousands)	
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
2009			
Natural gas, NGL and oil revenue	$ 608,013	$ 188,685	$ 796,698
Operating expense	112,935	38,661	151,596
Depletion expense	127,888	33,783	161,671
Impairment expense	786,867	192,673	979,540
	(419,677)	(76,432)	(496,109)
Income tax benefit	(146,887)	(22,165)	(169,052)
Results from producing activities	$ (272,790)	$ (54,267)	$ (327,057)

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 2011 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,		
	2011	2010	2009
Natural gas – Henry Hub, per MMBtu	$ 4.12	$ 4.38	$ 3.87
Natural gas – AECO, per MMBtu	3.65	4.08	3.76
NGL – Mont Belvieu, Texas, per Bbl	47.16	37.56	24.94
Oil – WTI Cushing, per Bbl	95.71	79.43	61.18

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, 2011, 2010 and 2009 was as follows:

	U.S.	Canada	Total
		(In thousands)	
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
December 31, 2009			
Future revenue	$ 7,787,422	$ 916,765	$ 8,704,187
Future production costs	(4,169,783)	(403,874)	(4,573,657)
Future development costs	(938,675)	(93,588)	(1,032,263)
Future income taxes	(222,576)	(47,125)	(269,701)
Future net cash flows	2,456,388	372,178	2,828,566
10% discount	(1,492,469)	(153,418)	(1,645,887)
Standardized measure of discounted future cash flows relating to proved reserves	$ 963,919	$ 218,760	$ 1,182,679

The primary changes in the Standardized Measure for 2011, 2010 and 2009 were as follows:

	Years Ended December 31, 2011	2010	2009
		(In thousands)	
Sales of oil and gas net of production costs	$ (477,883)	$ (643,349)	$ (645,102)
Net changes in economic factors	32,175	1,080,136	(715,484)
Extensions and discoveries	251,635	274,255	561,544
Development costs incurred	233,294	208,613	205,781
Changes in estimated future development costs	(60,642)	(341,612)	81,754
Purchase and sale of reserves, net	-	103,865	(144,279)
Revision of estimates	(224,784)	182,772	(248,681)
Accretion of discount	197,902	124,644	192,325
Net change in income taxes	1,404	(392,275)	196,691
Change in timing and other differences	(4,626)	6,650	(96,132)
Net increase (decrease)	$ (51,525)	$ 603,699	$ (611,583)

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 and 2009, which are all located in the U.S. In 2011, our investment in BBEP was eliminated and we no longer own any BBEP Units as of December 31, 2011. 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	2009
Ownership in BBEP at December 31,	29.44%	40.45%
Annualized weighted average ownership of BBEP	34.62%	40.45%

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

	For the Years Ended December 31, 2010 Total (Mboe)	2010 Gas (MMcf)	2010 Oil (MBbl)	2009 Total (Mboe)	2009 Gas (MMcf)	2009 Oil (MBbl)
Beginning balance	45,027	175,869	15,715	42,038	189,176	10,509
Revision of previous estimates	4,438	14,371	2,043	6,191	(4,203)	6,891
Purchase of reserves in place (1)	515	2,943	24	-	-	-
Sale of reserves in place (1)	(12,652)	(49,363)	(4,424)	(566)	(543)	(476)
Production	(2,319)	(7,357)	(1,093)	(2,636)	(8,561)	(1,209)
Ending balance	35,009	136,463	12,265	45,027	175,869	15,715
Proved developed reserves (2)						
Beginning balance	40,847	161,491	13,931	38,791	175,933	9,469
Ending balance	31,881	122,887	11,399	40,847	161,491	13,931
Proved undeveloped reserves (2) (3)						
Beginning balance	4,180	14,378	1,784	3,247	13,243	1,040
Ending balance	3,128	13,576	866	4,180	14,378	1,784

(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. During 2009, capital expenditures of $2.3 million were incurred and 11 wells drilled to convert 196 MMcf of natural gas and 230 MBbl of oil from proved undeveloped to proved developed.

(3) As of December 31, 2010 and 2009, no material proved undeveloped reserves have remained undeveloped for more than five years.

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

	Years Ended December 31, 2010	Years Ended December 31, 2009
Representative prices:		
Natural Gas-Henry Hub	$ 4.38	$ 3.87
Oil-WTI Cushing	79.40	61.18

The following table summarizes the carrying value of our portion of BBEP's consolidated oil and gas assets as of December 31, 2010.

	At December 31, 2010
Proved properties and related producing assets	$ 551,573
Pipeline and processing facilities	43,171
Unproved properties	33,291
Accumulated depreciation, depletion and amortization	(122,295)
Net capitalized costs	$ 505,740

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

	2010	2009
	(In thousands)	
Proved properties	$ 580	$ -
Unproved properties	996	-
Development costs	22,487	11,598
Asset retirement costs	3,349	1,975
Total	$ 27,412	$ 13,573

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

	2010	2009
	(In thousands)	
Oil, natural gas and NGL sales	$ 110,003	$ 103,126
Gain (loss) on commodity derivative instruments	12,156	(20,808)
Operating costs	(49,343)	(56,029)
Depreciation, depletion & amortization	(34,684)	(42,194)
Income tax benefit	71	618
Results from producing activities	$ 38,203	$ (15,287)

The following table summarizes our share of BBEP's Standardized Measure at December 31, 2010 and 2009:

	At December 31,	
	2010	2009
	(In thousands)	
Future revenues	$ 1,500,867	$ 1,552,493
Future development costs	(73,954)	(79,983)
Future production costs	(770,940)	(850,917)
Future net cash flows	655,973	621,593
10% discount	(342,435)	(314,290)
Standardized measure of discounted future cash flows relating to proved reserves	$ 313,538	$ 307,303

The following table summarizes our share of the primary changes in BBEP's Standardized Measure for 2010 and 2009:

	At December 31,	
	2010	2009
	(In thousands)	
Beginning balance	$ 307,303	$ 240,209
Sales, net of production costs	(51,587)	(47,097)
Net changes in sales and transfer prices, net of production expense	90,185	88,093
Previously estimated development costs incurred	14,053	11,748
Changes in estimated future development costs	(30,975)	(14,969)
Purchase of reserves in place [1]	493	–
Sale of reserves in place [1]	(83,651)	(2,231)
Revision of quantity estimates and timing of production	45,353	7,590
Accretion of discount	22,365	23,960
Ending balance	$ 313,539	$ 307,303

(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, 2011. In making this evaluation, our management considered the matters relating to the material weakness 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, 2011. In light of the material weakness described below, we revised our impairment analysis for midstream assets and 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 operation 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, 2011, 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, 2011, it did not maintain effective internal control over financial reporting due to a material weakness relating to the design and operating effectiveness of the computation of impairment of our non-oil and gas assets. The weakness relates to design deficiencies regarding the assessment of triggering events and the consideration of asset groupings; and other deficiencies related to the performance and documentation of a recovery test and other fair value computational matters.

The effectiveness of our internal control over financial reporting as of December 31, 2011, has been audited by Deloitte & Touche LLP, our independent registered public accounting firm, and they have issued an attestation report on the effectiveness of our internal control over financial reports, as stated in their report 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, 2011, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. In response to the identification of the material weakness, management has enhanced its process for documenting identification of impairment indicators, and the preparation and review of undiscounted recoverability tests and discounted cash flow analyses. Management believes that these enhancements and improvements, when repeated as applicable in future periods, remediate the material weakness described above.

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 internal control over financial reporting of Quicksilver Resources Inc. and subsidiaries (the "Company") as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company'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 by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the 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 a 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. A material weakness was identified relating to the design and operating effectiveness of the computation of impairment of non-oil and gas assets. This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the consolidated financial statements as of and for the year ended December 31, 2011, of the Company and this report does not affect our report on such financial statements.

In our opinion, because of the effect of the material weakness identified above on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2011 of the

Company. We considered the material weakness identified above in determining the nature, timing, and extent of audit tests applied in our audit of the 2011 consolidated financial statements, and this report does not affect our report dated April 15, 2012, which expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding the adoption of Accounting Standards Update No. 2010-3, "Oil and Gas Reserve Estimation Disclosures."

/s/ Deloitte & Touche LLP

Fort Worth, Texas
April 15, 2012

ITEM 9B. Other Information

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 recent press reports questioning the projected decline curves and economics of shale gas wells. We understand from the SEC that a number of other shale gas producers received similar subpoenas.

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 16, 2012 annual meeting of stockholders ("2012 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 2012 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 2012 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 2012 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 2012 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 2011" and "Certain Relationships and Related Transactions" in the 2012 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 2012 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 2012 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 2012 Proxy Statement is incorporated herein by reference.

Information regarding our directors' independence set forth under "Corporate Governance Matters – Independent Directors" in the 2012 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 2012 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	7/23/10	
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	11/8/10	
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	6/23/08	
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	5/8/06	
3.3	Amended and Restated Bylaws of Quicksilver Resources Inc.	8-K	001-14837	3.1	11/16/07	
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	11/1/04	
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	8/10/09	
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	12/22/05	
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	3/21/06	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	SEC File No.	Exhibit	Filing Date	Filed (†) or Furnished (‡) Herewith (as indicated)
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	3/15/10	
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	11/7/06	
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	3/15/10	
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	6/30/08	
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	7/10/08	
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	6/26/09	
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	8/17/09	
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					†

Exhibit No.	Exhibit Description	Incorporated by Reference Form	SEC File No.	Exhibit	Filing Date	Filed (†) or Furnished (‡) Herewith (as indicated)
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					†
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					†
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					†
4.16	Amended and Restated Rights Agreement, dated as of December 20, 2005, between Quicksilver Resources Inc. and Mellon Investor Services LLC, as Rights Agent	8-A/A	001-14837	4.1	12/21/05	
4.17	Amendment dated as of February 23, 2011 to the Amended and Restated Rights Agreement between Quicksilver Resources Inc. and Mellon Investor Services LLC, as rights agent	8-K	001-14837	4.1	2/24/11	
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	8/21/97	
10.2**	Quicksilver Resources Inc. Amended and Restated 2004 Non-Employee Director Equity Plan	8-K	001-14837	10.4	5/25/07	
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	1/28/05	
10.4**	Quicksilver Resources Inc. Fourth 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	5/25/06	
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	11/24/08	

Exhibit No.	Exhibit Description	Incorporated by Reference				Filed (†) or Furnished (‡) Herewith (as indicated)
		Form	SEC File No.	Exhibit	Filing Date	
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	11/24/08	
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	11/24/08	
10.9**	Form of Incentive Stock Option Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended					†
10.10**	Form of Nonqualified Stock Option Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan, as amended					†
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	5/25/06	
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	11/24/08	
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	5/25/06	
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	5/25/07	
10.15**	Quicksilver Resources Inc. 2010 Executive Bonus Plan	8-K	001-14837	10.1	12/10/09	
10.16**	Quicksilver Resources Inc. 2011 Executive Bonus Plan	8-K	001-14837	10.1	2/25/11	
10.17**	Description of 2011 Cash Bonuses					†
10.18**	Quicksilver Resources Inc. Amended and Restated Change in Control Retention Incentive Plan	8-K	001-14837	10.9	11/24/08	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	SEC File No.	Exhibit	Filing Date	Filed (†) or Furnished (‡) Herewith (as indicated)
10.19**	Quicksilver Resources Inc. Second Amended and Restated Key Employee Change in Control Retention Incentive Plan	8-K	001-14837	10.8	11/24/08	
10.20**	Quicksilver Resources Inc. Amended and Restated Executive Change in Control Retention Incentive Plan	8-K	001-14837	10.7	11/24/08	
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	11/8/10	
10.22	Amended and Restated Credit Agreement, dated as of February 9, 2007, among Quicksilver Resources Inc. and the lenders identified therein	8-K	001-14837	10.1	2/12/07	
10.23	Amended and Restated Credit Agreement, dated as of February 9, 2007, among Quicksilver Resources Canada Inc. and the lenders and/or agents identified therein	8-K	001-14837	10.2	2/12/07	
10.24	First Amendment to Combined Credit Agreements, dated as of February 4, 2008, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein	10-K	001-14837	10.30	3/15/10	
10.25	Second Amendment to Combined Credit Agreements, dated as of May 8, 2008, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein	10-K	001-14837	10.31	3/15/10	
10.26	Third Amendment to Combined Credit Agreements, dated as of May 28, 2008, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein	10-K	001-14837	10.32	3/15/10	
10.27	Fourth Amendment to Combined Credit Agreements, dated as of June 20, 2008, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein	8-K	001-14837	10.1	6/25/08	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	SEC File No.	Exhibit	Filing Date	Filed (†) or Furnished (‡) Herewith (as indicated)
10.28	Fifth Amendment to Combined Credit Agreements, dated as of August 4, 2008, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein	8-K	001-14837	10.1	8/5/08	
10.29	Sixth Amendment to Combined Credit Agreements, dated as of September 30, 2008, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein	10-K	001-14837	10.35	3/15/10	
10.30	Seventh Amendment to Combined Credit Agreements, dated as of April 20, 2009, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein	10-K	001-14837	10.36	3/15/10	
10.31	Eighth Amendment to Combined Credit Agreements, dated as of May 28, 2009, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein	8-K	001-14837	10.1	6/17/09	
10.32	Letter Agreement, dated as of June 15, 2009, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein	8-K	001-14837	10.1	6/17/09	
10.33	Ninth Amendment to the Combined Credit Agreements, dated as of September 17, 2010, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein	10-Q	001-14837	10.1	11/8/10	
10.34	Tenth Amendment to the Combined Credit Agreements, dated as of December 21, 2010, among Quicksilver Resources Inc., Quicksilver Resources Canada Inc. and the agents and combined lenders identified therein	8-K	001-14837	10.1	12/22/10	
10.35	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	11/9/11	

Exhibit No.	Exhibit Description	Incorporated by Reference				Filed (†) or Furnished (‡) Herewith (as indicated)
		Form	SEC File No.	Exhibit	Filing Date	
10.36	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	12/27/11	
10.37	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	11/9/11	
10.38	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	12/27/11	
10.39	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	5/19/09	
10.40	Asset Purchase Agreement, dated May 11, 2010, between Marshall R. Young Oil Co., as Seller, and Quicksilver Resources Inc., as Buyer	8-K	001-14837	10.1	5/12/10	
10.41	Confidentiality Agreement dated October 24, 2010 among Quicksilver Resources Inc. and Quicksilver Energy L.P	8-K	001-14837	10.1	10/25/10	
10.42	Confidentiality Agreement dated October 26, 2010 among Quicksilver Resources Inc. and SPO Partners II, L.P.	8-K	001-14837	10.1	10/26/10	
10.43	Limited Waiver dated as of February 23, 2011 between Quicksilver Resources Inc. and Quicksilver Energy L.P.	8-K	001-14837	10.1	2/24/11	
10.44	Limited Waiver dated as of February 23, 2011 between Quicksilver Resources Inc. and SPO Partners II, L.P.	8-K	001-14837	10.2	2/24/11	
10.45	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	4/14/11	
10.46	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	4/14/11	

Exhibit No.	Exhibit Description	Incorporated by Reference				Filed (†) or Furnished (‡) Herewith (as indicated)
		Form	SEC File No.	Exhibit	Filing Date	
10.47	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	12/27/11	
10.48	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	12/27/11	
10.49	Gas Gathering Agreement, effective December 1, 2009, between Cowtown Pipeline L.P. and Quicksilver Resources Inc.	8-K	001-33631	10.1	1/8/10	
10.50	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	10.18	2/25/11	
10.51	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	11/6/08	
10.52	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	10.15	3/15/10	
10.53	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	10.16	2/25/11	
10.54	Amended and Restated Gas Gathering Agreement, effective September 1, 2008, between Cowtown Pipeline L.P. and Quicksilver Resources Inc.					†
10.55	First Amendment to Amended and Restated Gas Gathering Agreement, dated September 29, 2009, between Cowtown Pipeline L.P. and Quicksilver Resources Inc.					†

Exhibit No.	Exhibit Description	Incorporated by Reference Form	SEC File No.	Exhibit	Filing Date	Filed (†) or Furnished (‡) Herewith (as indicated)
10.56	Second Amendment to Gas Gathering Agreement, dated October 1, 2010, between Cowtown Pipeline L.P. and Quicksilver Resources Inc.					†
21.1*	List of subsidiaries of Quicksilver Resources Inc.					†
23.1	Consent of Deloitte & Touche LLP					†
23.2	Consent of Schlumberger Data and Consulting Services					†
23.3	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 Data and Consulting Services					†
99.2	Report of LaRoche Petroleum Consultants, Ltd.					†

* Excludes schedules and exhibits we agree to furnish supplementally to the SEC upon request

** Indicates a management contract or compensatory plan or arrangement

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: April 15, 2012

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 Thomas F. Darden	Chairman of the Board; Director	April 15, 2012
/s/ Glenn Darden Glenn Darden	President and Chief Executive Officer (Principal Executive Officer); Director	April 15, 2012
/s/ Philip Cook Philip Cook	Executive Vice President – Chief Financial Officer (Principal Financial Officer)	April 15, 2012
/s/ John C. Regan John C. Regan	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)	April 15, 2012
/s/ Anne Darden Self Anne Darden Self	Director	April 15, 2012
/s/ W. Byron Dunn W. Byron Dunn	Director	April 15, 2012
/s/ Steven M. Morris Steven M. Morris	Director	April 15, 2012
/s/ Yandell Rogers, III W. Yandell Rogers, III	Director	April 15, 2012
/s/ Mark J. Warner Mark J. Warner	Director	April 15, 2012

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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

Jeff Cook
Executive Vice President – Operations

Philip W. Cook [1]
Executive Vice President – Chief Financial Officer

John C. Cirone
Executive Vice President – General Counsel

Stan G. Page
Senior Vice President – U.S. Operations

C. Clay Blum
Vice President – U.S. Land

John Callanan
Vice President – Geology

Scott Herstein
Vice President – Acquisitions & Divestitures

John E. Hinton
Vice President – Finance & Investor Relations

Vanessa G. LaGatta
Vice President – Treasurer

Chris M. Mundy
Vice President – Engineering

John C. Regan [1]
Vice President, Controller & Chief Accounting Officer

Clifford C. Rupnow
Vice President – Midstream Development

Anne D. Self
Vice President – Human Resources

[1] *Mr. Regan will succeed Mr. Cook as Chief Financial Officer on April 16, 2012.*

HEADQUARTERS

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Fort Worth, Texas 76102
Phone: 817-665-5000
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quicksilver@qrinc.com
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MAJOR SUBSIDIARY

Quicksilver Resources Canada Inc.
One Palliser Square
2000, 125-9th Avenue, SE
Calgary, Alberta Canada
T2G 0P8
Phone: 403-537-2455
Fax: 403-262-6115

J. David Rushford
Senior Vice President and Chief Operating Officer

REGISTRAR AND TRANSFER AGENT

Computershare
480 Washington Blvd.
Jersey City, New Jersey 07310-1900
Phone: 866-637-5420
www.bnymellon.com/shareowner/equityaccess

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Deloitte & Touche LLP
201 Main Street, Suite 1501
Fort Worth, Texas 76102

ANNUAL MEETING

The Company's Annual Meeting of Stockholders is scheduled for 9:00 a.m., May 16, 2012
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*

All information as of March 31, 2012

CORPORATE **INFORMATION**

QUICKSILVER
RESOURCES

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817.665.5000
www.qrinc.com

NYSE: KWK