2008 Annual Report

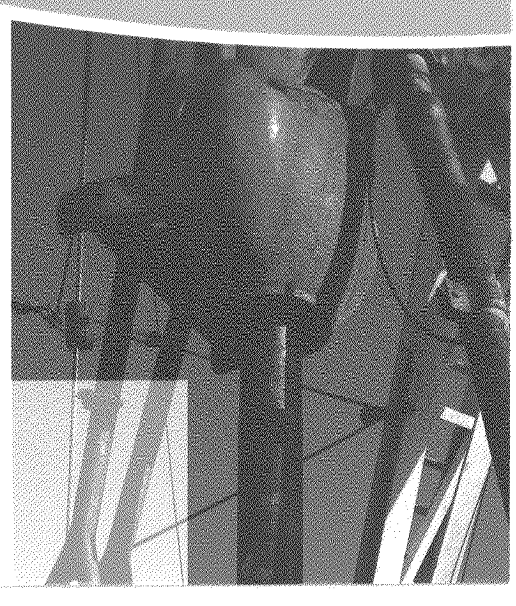
QUICKSILVER
RESOURCES

COMPANY PROFILE

Quicksilver Resources Inc. is an independent exploration and production company focused on identifying, acquiring and developing unconventional reservoirs of natural gas 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 basins including shale gas and coalbed methane. The company's core developments are located in the shales of the Fort Worth Basin and the coals in the Canadian province of Alberta.

As of December 31, 2008, the company had estimated proved reserves of approximately 2.2 trillion cubic feet of natural gas equivalents, of which 99 percent were natural gas or natural gas liquids and 63 percent were proved developed. The company also owns approximately 73 percent of Quicksilver Gas Services LP, a midstream limited partnership and approximately 41 percent of BreitBurn Energy Partners L.P., an exploration and production limited partnership.

Quicksilver is a net asset value company which focuses on growth by the drill-bit through finding and developing long-life unconventional natural gas reservoirs as a low-cost producer. The company's common shares are traded on the New York Stock Exchange under the ticker symbol KWK.



TO OUR STOCKHOLDERS

2008 was a remarkable year. What began as the best of times for natural gas producers, ended with a steep drop in natural gas prices as the sector followed other industries into a global economic recession. The fall was steep for all and Quicksilver's stock price was hit significantly. What is not reflected in that stock price is the quality, size, and longevity of Quicksilver's asset base.

Today this company has a larger and stronger set of assets than anytime in our history. This past year Quicksilver once again set records for production, total reserves, and cash flow from operations. Our assets are the natural gas & oil reserves in the ground and the facilities to produce those reserves. Quicksilver has always taken a long-term approach to the business, a view that matches well with the 30+ year life of the reservoirs. Once we capture these reserves our mission is to produce them at a low cost which can both extend the life and enhance the returns.

2008 was an outstanding year for the company in that respect as we replaced 473% of production via the drill bit at a finding and development cost of $2.14/MCFE and reduced our average unit production costs 20% year-over-year. Overall the company grew reserves 42% to 2.2 trillion cubic feet equivalent by year-end 2008.

Historically Quicksilver has utilized debt more than issuing equity to fund our drilling and acquisition programs. We have used a commodity hedging program to mitigate the risks of that debt and lock-in predictable cash flows. With the company's low cost structure, this has been an efficient and highly accretive way to grow. In today's new world, debt is viewed through a different lens with an extreme tightening of the world credit markets and the decrease in commodity prices.

Fortunately, Quicksilver has hedged approximately 75% and 50% of our expected natural gas production for 2009 and 2010, respectively, at very attractive prices. In addition, the company has secured firm pipeline capacity to transport our products to the highest value markets. On the debt side, the company's first debt maturity is in 2012, and more than 50% of the company debt is due between 2013 and 2016.

Quicksilver's property portfolio provides significant flexibility that enables us to optimize exploratory and development activities and cash flows even in this rapidly changing environment. We have reduced our 2009 capital program and are committed to operate within our total cash inflows. Yet even at these reduced capital levels, we expect to increase our average daily production volumes and begin the evaluation of our exciting new project in the Horn River Basin of British Columbia. We believe this project will provide the next chapter in Quicksilver's growth story.

Challenging times provide opportunities. Our plan is to live within cash flow, continue to lower the company's cost structure, pay down debt, and weather this storm. We firmly believe when the industry recovers Quicksilver can be in a stronger position to take advantage of those opportunities.

Last month we recognized Quicksilver's 10th anniversary as a public company. During this time period, the shareholders of the company have participated in more than a four-fold increase or an approximate 15% compound annual growth of our share price. Our talented team of co-workers and our dedicated board of directors are working hard to achieve even more in the decade ahead. We thank all of you for your support.

Very truly yours,

Glenn Darden
President and CEO

Thomas F. Darden
Chairman

FINANCIAL HIGHLIGHTS

In thousands, except per share, production and product price data	2008 [a]	2007 [a]	2006 [a]	2005 [a]	2004 [a]
Total revenues	$800,641	$561,258	$390,362	$310,448	$179,729
Income (loss) before income taxes and minority interest	(578,489)	736,941	131,960	127,974	45,446
Net income (loss) [b]	$(373,994)	$479,378	$93,719	$87,434	$31,272
Net income (loss) per diluted share [b]	$(2.31)	$2.86	$0.58	$0.54	$0.21
Diluted weighted average number of shares outstanding for the periods	161,622	168,029	166,266	164,912	154,030
Total assets	$4,500,571	$2,775,846	$1,882,912	$1,243,094	$888,334
Long-term debt	$2,605,025	$813,817	$919,117	$506,039	$399,134
Total stockholders' equity	$1,094,709	$1,068,355	$575,666	$383,615	$304,276
Natural gas production (Mmcf)	68,128	59,619	53,266	46,769	39,351
Average realized natural gas price per Mcf [c]	$8.10	$6.73	$6.05	$5.76	$3.83
NGL production (Mmcfe)	25,176	14,826	4,476	1,338	774
Average realized NGL price per Mcfe [c]	$7.57	$7.21	$6.48	$6.51	$4.75
Crude oil production (Mbbl)	483	584	587	553	689
Average realized price per Bbl [c]	$78.83	$63.87	$59.99	$50.50	$33.07

[a] Share and per share amounts have been adjusted to reflect a two-for-one stock split during June 2004, a three-for-two stock split during June 2005 and a two-for-one stock split during January 2008.

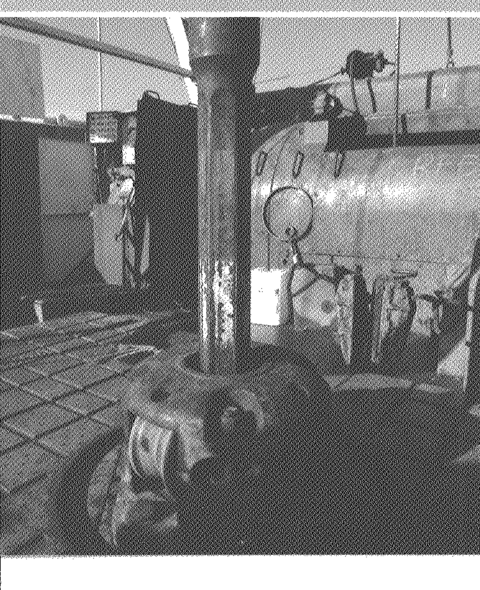
[b] Net loss and net loss per diluted share for 2008 include approximately $620 million and $3.84 per diluted share, respectively, associated with impairment charges on U.S. oil and gas properties and investment in BreitBurn Energy Partners LP. Net income and net income per diluted share for 2007 include $363.3 million and $2.16 per diluted share, respectively, associated with the gain on sale of all of our Northeast Operations net of divestiture-related expenses and costs and the loss on related natural gas sales contracts.

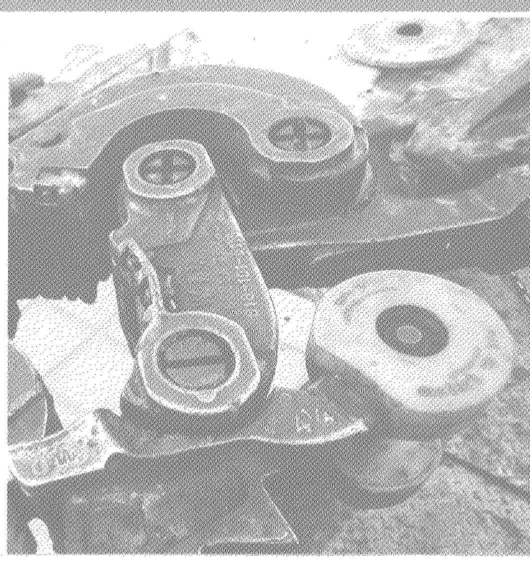
[c] Average realized prices reflect the effect of hedging transactions.

In 2008, Quicksilver's Chief Executive Officer submitted the CEO Certification to the New York Stock Exchange.

The statements in this Annual Report regarding future events, occurrences, circumstances, activities, performance, outcomes and results are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Although these statements reflect the current views, assumptions and expectations of Quicksilver Resources' management, the matters addressed herein are subject to numerous risks and uncertainties, which could cause actual activities, performance, outcomes and results to differ materially from those indicated. Factors that could result in such differences or otherwise materially affect Quicksilver Resources' financial condition, results of operations and cash flows include: changes in general economic conditions; fluctuations in natural gas, natural gas liquids and crude oil prices; failure or delays in achieving expected production from exploration and development projects; uncertainties inherent in estimates of natural gas, natural gas liquids and crude oil reserves and predicting natural gas, natural gas liquids and crude oil reservoir performance; effects of hedging natural gas, natural gas liquids and crude 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, customers and counterparties; changes in the availability and cost of capital; delays in obtaining oilfield equipment and increases in drilling and other service costs; 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; and the effects of existing or future litigation; as well as, other factors disclosed in Quicksilver Resources' filings with the Securities and Exchange Commission. Except as required by law, we do not intend to update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

Please refer to the calculations of Finding & Development Costs and Production Replacement Ratio that follow the signature page of the Form 10-K.





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, 2008

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**

SEC
Mail Processing
Section
APR 01 2009
Washington, DC
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QUICKSILVER RESOURCES INC.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**75-2756163** (I.R.S. Employer Identification No.)
777 West Rosedale St., Fort Worth, Texas (Address of principal executive offices)	**76104** (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 [X] No [ ]

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

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 [X] 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 definition of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]
(Do not check if a 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 [X]

As of June 30, 2008, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $4,067,732,259 based on the closing sale price of $38.64 as reported on the New York Stock Exchange.

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

Class	Outstanding at February 13, 2009
Common Stock, $0.01 par value per share	168,752,835 shares

DOCUMENTS INCORPORATED BY REFERENCE

Document	Parts Into Which Incorporated
Proxy Statement for the Registrant's May 20, 2009 Annual Meeting of Stockholders	Part III

INDEX TO ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2008

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.

DEFINITIONS

As used in this annual report unless the context otherwise requires:

"**AECO**" is a reference, in dollars per MMbtu, for gas delivered onto the NOVA Gas Transmission Ltd. System in Alberta, Canada

"**Bbl**" or **"Bbls**" means barrel or barrels

"**Bbld**" means barrel or barrels per day

"**Bcf**" means billion cubic feet

"**Bcfd**" means billion cubic feet per day

"**Bcfe**" means Bcf of natural gas equivalents, calculated as one Bbl of oil or NGLs equaling six Mcf of gas

"**Btu**" means British Thermal Units, a measure of heating value

"**Canada**" means the division of Quicksilver encompassing oil and natural gas properties located in Canada

"**CBM**" means coalbed methane

"**DD&A**" means Depletion, Depreciation and Accretion

"**Domestic**" means the properties of Quicksilver in the continental United States

"**LIBOR**" means London Interbank Offered Rate

"**MBbl**" or "**MBbls**" means thousand barrels

"**MBbld**" means thousand barrels per day

"**MMBbls**" means million barrels

"**MMBtu**" means million Btu and is approximately equal to 1 Mcf of natural gas

"**MMBtud**" means million Btu 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, calculated as one Bbl of oil or NGLs equaling six Mcf of gas

"**MMcfed**" means MMcf of natural gas equivalents per day, calculated as one Bbl of oil or NGLs equaling six Mcf of gas

"**NGL**" or "**NGLs**" means natural gas liquids

"**NYMEX**" means New York Mercantile Exchange

"**Oil**" includes crude oil and condensate

"**Tcf**" means trillion cubic feet

"**Tcfe**" means Tcf of natural gas equivalents, calculated as one Bbl of oil or NGLs equaling six Mcf of gas

COMMONLY USED TERMS

Other commonly used terms and abbreviations include:

"**Alliance Acquisition**" means the August 8, 2008 purchase of leasehold, royalty and midstream assets in the Barnett Shale in northern Tarrant and southern Denton counties of Texas

"**BBEP**" means BreitBurn Energy Partners L.P.

"**BreitBurn Transaction**" means the November 1, 2007 conveyance of our Northeast Operations in exchange for aggregate proceeds of $1.47 billion

"**FASB**" means the Financial Accounting Standards Board, which promulgates accounting standards in the U.S.

"**GAAP**" means accounting principles generally accepted in the United States

"**IPO**" means the KGS initial public offering completed on August 10, 2007

"**KGS**" means Quicksilver Gas Services LP, which is our publicly-traded partnership and trades under the ticker symbol "KGS"

"**Mercury**" means Mercury Exploration Company, which is owned by members of the Darden family

"**Michigan Sales Contract**" means the gas supply contract which terminates in March 2009 under which we agreed to deliver 25 MMcfd at a floor price of $2.49 per Mcf

"**Northeast Operations**" means the oil and gas properties and facilities in Michigan, Indiana and Kentucky which were conveyed to BreitBurn Operating, L.P. on November 1, 2007

"**PCAOB**" means the Public Company Accounting Oversight Board

"**SEC**" means the United States Securities and Exchange Commission

"**SFAS**" means Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board

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 crude oil prices;
- failure or delays in achieving expected production from exploration and development projects;
- uncertainties inherent in estimates of natural gas, NGL and crude oil reserves and predicting natural gas, NGL and crude oil reservoir performance;
- effects of hedging natural gas, NGL and crude 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, customers and counterparties;
- changes in the availability and cost of capital;
- delays in obtaining oilfield equipment and increases in drilling and other service costs;
- 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;
- the effects of existing or future litigation; and
- certain factors discussed 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.

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

PART I

ITEM 1. Business

GENERAL

Quicksilver Resources Inc., including its subsidiaries, ("Quicksilver" or the "Company") is an independent energy company engaged primarily in exploration, development and production of unconventional natural gas onshore in North America. We own producing oil and natural gas properties in the United States, principally in Texas, Wyoming and Montana, and in Alberta, Canada, which had estimated total proved reserves of approximately 2.2 Tcfe of natural gas at December 31, 2008. We also explore for natural gas onshore in North America, principally in the Horn River Basin of Northeast British Columbia and the Delaware Basin of West Texas. In addition, our new ventures team actively studies other basins in North America for unconventional natural gas opportunities which may yield future exploration opportunities. We also own approximately 73% of KGS, a publicly traded midstream master limited partnership controlled by us, and we own approximately 41% of the limited partner units of BBEP, a publicly-traded oil and natural gas exploration and production master limited partnership.

Our common stock trades under the symbol "KWK" on the New York Stock Exchange. Our principal and administrative offices are located at 777 West Rosedale St., Fort Worth, Texas 76104. The units of KGS are publicly traded on the NYSE Arca under the ticker symbol "KGS" and the units of BBEP are traded on the NASDAQ Global Select Market under the ticker symbol "BBEP."

FORMATION AND DEVELOPMENT OF BUSINESS

Through our predecessors, we began operations in 1963 as a privately-held company controlled by members of the Darden family. We were organized as a Delaware corporation in 1997 and became a public company in 1999. As of December 31, 2008, members of the Darden family and entities controlled by them, beneficially owned approximately 30% of our outstanding common stock.

STRATEGIC ACQUISITION

In August 2008, we completed the $1.3 billion Alliance Acquisition that consisted of producing and non-producing leasehold, royalty and midstream assets that we believe complements our existing operations in the Fort Worth Basin of North Texas. Consideration in the transaction was $1 billion in cash and $262 million in Quicksilver common stock. We funded the cash portion of the transaction by drawing $675 million on our Senior Secured Second Lien Facility and drawing the remainder on our Senior Secured Credit Facility. We estimate that the 13,000 net acres acquired contain more than one trillion cubic feet of net recoverable natural gas resources, including 299 Bcf classified as proved at the time of the acquisition.

BUSINESS STRATEGY

We have a multi-pronged strategy to increase share value through cost-effective growth in production and reserves by focusing on unconventional natural gas plays onshore in North America. This strategy takes advantage of the Company's proven record and expertise in identifying and developing properties containing fractured shales, coalbed methane and tight sands. Our strategy includes the following key elements:

Focus on core areas of repeatable, low-risk development: We intend to invest the vast majority of our 2009 capital budget on low-risk development and exploitation projects on our extensive leasehold positions in the Fort Worth and Western Canadian Sedimentary basins. In 2009, we expect to concentrate our drilling in our Barnett Shale properties in the Fort Worth Basin of North Texas and in our Canadian CBM properties in Alberta, Canada. We believe that operating in concentrated areas allows us to more efficiently deploy our resources, manage costs and leverage our base of technical expertise.

Pursue disciplined organic growth opportunities: We intend to invest approximately 10% of our 2009 capital budget in high-potential, longer cycle-time exploration projects to replenish our inventory of development projects for the future. Through our activities in each of the Fort Worth and Western Canadian

Sedimentary basins, we have developed significant expertise in identifying, developing and producing fractured shales, coal seams and tight sands. We are focused on identifying and evaluating opportunities that allow us to apply this expertise and experience to the development and operation of other unconventional reservoirs in North America. In 2009, we will focus our exploratory activities on our 127,000 acres in the Horn River Basin of Northeast British Columbia where we hold a 100% working interest. We also expect to complete the exploratory evaluation of our acreage in the Delaware Basin of West Texas in 2009. In addition, we may seek to acquire similar acreage positions for future exploration activities.

Enhance profitability through control and marketing of our equity natural gas and crude oil: We 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. We believe this allows us to better manage the physical movement of our production and the costs 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. We continue to control our midstream operations in the Fort Worth Basin through our approximate 73% interest in KGS, including 100% of its general partner. KGS brought on line an additional 125 Mmcfd of processing capacity during the first quarter of 2009.

Maintain flexible financial profile: We believe that a conservative financial structure will better position us to capitalize on opportunities and to limit our financial risk. Our ownership interests in KGS and BBEP provide additional financial flexibility for the Company while enabling us to participate in the expected future growth of both these entities. In addition, to help ensure a level of predictability in the prices we receive for our natural gas and crude oil production, we hedge the commodity price of all of our products with financial instruments covering a substantial portion of our production. We regularly review the credit-worthiness of our hedging counterparties, and our hedging program is spread among numerous financial institutions, all of which participate in our credit facility.

BUSINESS STRENGTHS

High-quality asset base with long reserve life: Our proved reserves of approximately 2.2 Tcfe as of December 31, 2008, were approximately 99% natural gas and NGLs and approximately 63% proved developed. The majority of these reserves are located in our core areas in the Fort Worth Basin in North Texas and the Western Canadian Sedimentary Basin in Alberta, which accounted for approximately 84% and 15%, respectively, of our proved reserves. Based on our annualized fourth-quarter 2008 average production from these properties, our implied reserve life (proved reserves divided by annualized fourth-quarter 2008 production) was 18.5 years and our implied proved developed reserve life (proved developed reserves divided by annualized fourth quarter 2008 production) was 11.6 years. We believe our assets are characterized by long reserve lives and predictable well production profiles. As of December 31, 2008, we operated properties containing approximately 99% of our proved reserves.

Multi-year inventory of development and exploitation drilling projects: As of December 31, 2008, we owned leases covering more than 542,000 net acres in our two core areas, of which approximately 42% were undeveloped. Within the Fort Worth Basin alone, we have more than 1,650 identified drilling locations, which at the 2009 anticipated drilling rate of proved reserves, provide us with a 10-year inventory of drilling locations. 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 the Fort Worth Basin. For 2009, we have budgeted approximately $400 million for drilling activities.

Proven record of organic growth in reserves and production: During the past three years, we have added approximately 1.5 Tcfe of proved reserves from organic development drilling activities. We have supplemented this activity with the Alliance Acquisition, which added 299 Bcfe of proved reserves at the time of its purchase and divested approximately 546 Bcfe of proved reserves associated with our former Northeast Operations in 2007. Excluding acquisition and divestiture activity, we have replaced approximately 78% of our reserves during the years ended December 31, 2008. Our growth has resulted from our ability to acquire attractive undeveloped acreage and apply our technical expertise to find, develop and produce reserves. In recent years, we have demonstrated this ability through our accomplishments in our two core areas. We believe our current acreage position will provide opportunities to continue our reserve and production growth.

Midstream strength: Our midstream operations, which are owned or operated by KGS, are well positioned to complement our growth initiatives in the Fort Worth Basin and to compete with other midstream providers for unaffiliated business. Quicksilver's operational structure allows our midstream operations to more accurately forecast future gathering and processing estimates and to assess the need and timing for capacity additions. KGS' assets in the Fort Worth Basin are well positioned to expand the gathering system footprint, increase throughput volumes and plant utilization which ultimately increase cash flows.

Experienced management and technical team: Our CEO, Glenn Darden, and our Chairman, Thomas Darden, are founding members of our company and have held executive positions at Quicksilver since our formation. They both have been in the oil and natural gas business their entire professional careers. Since our formation, they, along with an 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 resources. Our executive management team is supported by a core team of technical and operating managers who have significant industry experience, including experience in drilling and completing horizontal wells and in unconventional reservoirs.

FINANCIAL INFORMATION ABOUT SEGMENT AND GEOGRAPHICAL AREAS

The consolidated financial statements included in Item 8 of this annual report contain information on our segments and geographical areas, which is incorporated herein by reference.

PROPERTIES

Substantially all of our properties consist of interests in developed and undeveloped oil and natural gas leases and mineral acreage. In addition, we have midstream assets, including natural gas and NGL processing plants and related gathering and treating systems. Our midstream operations in the Fort Worth Basin are conducted by KGS, of which we own approximately 73% of the partnership interests, including 100% of its general partner. We also indirectly own interests in other oil and natural gas properties through our ownership of approximately 21.348 million limited partnership units in BBEP, approximately 41% of their partnership interests.

OIL AND NATURAL GAS OPERATIONS

Our oil and natural gas operations are focused onshore in North America, primarily in unconventional natural gas plays. Our current production and development operations are concentrated in the Fort Worth and Western Canadian Sedimentary basins. At December 31, 2008, we had estimated total proved reserves of approximately 2.2 Tcfe, approximately 99% of which were natural gas and NGLs and approximately 63% of which were proved developed. Approximately 84% of our reserves at December 31, 2008 were located in Texas and approximately 15% were in Canada. For the year ended December 31, 2008, we had average production of 262.8 MMcfe per day and total production of 96.2 Bcfe. Since going public in 1999, we have grown our reserves and production at an approximate compound annual growth rate of 25% and 19% respectively.

Texas

The Barnett Shale play in the Fort Worth Basin in North Texas comprised 84% of our total estimated proved reserves and approximately 75% of our total average daily production for 2008. In the quarter ended December 31, 2008, our net production from wells in the Fort Worth Basin was approximately 259 MMcfed. We expect our 2009 production from Texas to represent approximately 80% of our 2009 production.

At December 31, 2008, we held approximately 192,000 net acres in the Fort Worth Basin of which approximately 34% is currently developed. We have identified more than 1,650 remaining potential drilling locations. Much of our acreage in Hood and Somervell counties contains high-Btu natural gas which contains NGLs within the natural gas stream. We gather our production and process the high-Btu natural gas through our midstream system that is owned and operated by KGS. Effective in the first quarter of 2009, this system includes processing facilities which have the capacity to process more than 325 MMcfd of natural gas.

KGS manages approximately 350 miles of natural gas gathering pipelines, ranging up to 20 inches in diameter, all located in the Fort Worth Basin. Additionally, KGS owns two NGL pipelines that interconnect with pipelines owned by third parties. The pipeline system gathers and delivers natural gas produced by our wells and those of third parties to the processing facilities. We expect to continue to construct additional gathering assets as additional wells in the Fort Worth Basin are developed. Our capital expenditures budget for 2009 includes approximately $155 million for midstream assets, including $35 million to be spent by KGS.

During 2008, we drilled 296 gross (259.7 net) wells in the Fort Worth Basin primarily from multi-well drilling pads. On these multi-well pads, all the wells are drilled prior to initiating completion activities. At December 31, 2008, we had drilled a total of 703 gross (620.1 net) wells in the Fort Worth Basin since we began exploration and development operations in 2003. In 2008, we completed 255 gross (222.6 net) wells and tied 256 gross (226.8 net) wells into sales.

We also control approximately 475,000 net acres in West Texas, predominantly in the Delaware Basin. Through December 31, 2008, we had drilled or re-entered wells on that acreage to evaluate horizontal and vertical opportunities within both the Barnett and Woodford shale formations. We expect to complete this evaluation during 2009.

The portion of the 2009 capital budget allocated to our Texas interests is approximately $475 million. At December 31, 2008, we had six drilling rigs operating for us in the Fort Worth Basin, and we expect to utilize as many as nine rigs in this area during 2009.

Rocky Mountain Region

Our Rocky Mountain producing properties are located in Montana and Wyoming. Production from those properties is primarily crude oil from established formations at depths ranging from 1,000 feet to 17,000 feet. At December 31, 2008, our Rocky Mountain proved reserves were approximately 1.9 MMBbls of crude oil and 1.6 MMcfe of natural gas and NGLs for total equivalent reserves of 13 Bcfe. Daily production from our properties in the Rocky Mountain region averaged 3.1 MMcfed for 2008.

Canada

At December 31, 2008, Canadian reserves of 333 Bcfe, primarily attributable to our CBM projects in Alberta, comprised 15% of our total reserves. 2008 production averaged 63 MMcfed, representing approximately 24% of our total 2008 production and Canadian production averaged 65 MMcfed during the fourth quarter of 2008.

As of December 31, 2008, we had approximately 161,000 gross (102,000 net) undeveloped acres in Alberta, Canada. On this acreage, we drilled 373 gross (156.9 net) productive wells with 356 gross (144.7 net) wells tied into sales in 2008. During 2009, we expect to tie into sales all of the approximately 180 wells completed but not producing at December 31, 2008. These expenditures were fully funded by Canadian cash flows from operations, which we expect to continue in 2009.

In 2008, we acquired an additional 50,000 acres in the Horn River Basin of Northeast British Columbia resulting in a total of approximately 127,000 contiguous acres in this basin. We spud our first exploratory well on this acreage in 2008 and spud a second well in the first quarter of 2009.

Other Properties

We believe that our 2009 and 2010 growth will be through development of our leasehold interests in our core areas in the Barnett Shale and CBM formations in Alberta. In addition, we are actively exploring the Horn River Basin in Northeast British Columbia and the Delaware Basin in West Texas. We believe that our future reserve and production growth will come primarily from our Texas and Canadian operations. We may also pursue acquisitions of additional undeveloped leasehold interests, which could allow for further capitalization on our proven expertise in unconventional gas plays.

2009 Capital Program

We intend to focus our capital spending program primarily on the continued development of our properties in Texas and Alberta. For 2009, we have established a capital budget of $600 million, of which we have allocated $400 million for drilling activities, $155 million for gathering and processing facilities, including approximately $35 million to be funded directly by KGS, $40 million for acquisition of additional leasehold interests and $5 million for other property and equipment. On a regional basis, approximately $475 million has been allocated to Texas to drill approximately 180 wells on operated properties and to tie in approximately 100 such wells. Canada has been allocated $110 million to maintain current production levels though the drilling of approximately 180 wells and to begin exploratory activities in the Horn River Basin. The remaining capital budget is spread among our other operating areas. The budget for gathering and processing expenditures includes $114 million in Texas, which includes $35 million of expenditures to be funded by KGS, and $41 million in Canada.

OIL AND NATURAL GAS RESERVES

The following reserve quantity and future net cash flow information concerns our proved reserves. Independent petroleum engineers with Schlumberger Data and Consulting Services and LaRoche Petroleum Consultants, Ltd. prepared our reserve estimates for our U.S. and Canadian properties, respectively. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas, and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Prices include consideration of changes in existing prices provided by contractual arrangements but not of escalations based upon expected future conditions. Future production and development costs include production and property taxes.

Proved developed oil and natural gas reserves are reserves that are expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil and natural gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for re-completion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

The reserve data set forth in this document represents only estimates and is subject to inherent uncertainties. The determination of oil and natural gas 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 the reserve estimates contained in this document are reasonable, reserve estimates are imprecise and are expected to change as additional information becomes available.

The following table summarizes our proved reserves and the standardized measure of discounted future net cash flows attributable to them at December 31, 2008, 2007 and 2006 in accordance with the rules established by the SEC, which includes requirements to maintain year-end pricing over the entire production horizon.

	Total Proved Reserves			Proved Developed Reserves		
	For the Years Ended December 31,			For the Years Ended December 31,		
	2008	2007	2006	2008	2007	2006
Natural gas (MMcf)						
United States	1,306,497	662,409	933,342	756,191	379,917	626,582
Canada	332,571	328,381	308,335	278,668	260,029	217,759
Total	1,639,068	990,790	1,241,677	1,034,859	639,946	844,341
NGL (MBbl)						
United States	91,927	90,055	47,985	56,181	50,738	18,771
Canada	8	10	16	8	10	16
Total	91,935	90,065	48,001	56,189	50,748	18,787
Crude oil (MBbl)						
United States	2,914	3,074	6,315	2,509	2,763	5,236
Canada	-	-	-	-	-	-
Total	2,914	3,074	6,315	2,509	2,763	5,236
Total (MMcfe)	2,208,162	1,549,624	1,567,573	1,387,047	961,012	988,477

	Years Ended December 31,		
	2008	2007	2006
Representative prices:			
Natural gas – Henry Hub Spot[1]	$ 5.71	$ 6.80	$ 5.64
Natural gas – AECO[1]	5.44	6.35	5.39
NGL – Mont Belvieu, Texas	21.65	57.35	40.10
NGL – Kalkaska, Michigan[2]	N/A	N/A	37.73
Crude oil – WTI Cushing[1]	44.60	95.98	60.85
Standardized measure of discounted future net cash flows[3], after income tax (in millions)	$ 1,794.3	$ 2,169.2	$ 1,485.8

(1) The natural gas and crude oil prices as of each respective year end were based, respectively, on NYMEX Henry Hub and AECO prices per MMBtu and NYMEX prices per Bbl, adjusted to reflect local differentials

(2) All Michigan NGL reserves were sold in 2007 pursuant to the BreitBurn Transaction, which is more fully described in Note 5 to the consolidated financial statements

(3) Determined based on year end unescalated prices and costs in accordance with the guidelines of the SEC, discounted at 10% per annum

VOLUMES, SALES PRICES AND OIL AND GAS PRODUCTION EXPENSE

The discussion of volumes 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.

DRILLING ACTIVITY

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

	Years Ended December 31,					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Development:						
United States						
Productive	292.0	255.7	258.0	226.2	41.0	32.8
Non-productive	1.0	1.0	-	-	-	-
Canada						
Productive	372.0	155.9	351.0	179.1	162.0	86.6
Non-productive	1.0	1.0	-	-	-	-
Total	666.0	413.6	609.0	405.3	203.0	119.4
Exploratory:						
United States						
Productive	5.0	4.1	32.0	19.2	160.0	126.4
Non-productive	2.0	2.0	4.0	3.2	8.0	8.0
Canada						
Productive	-	-	5.0	5.0	238.0	128.6
Non-productive	-	-	-	-	-	-
Total	7.0	6.1	41.0	27.4	406.0	263.0
Total:						
Productive	669.0	415.7	646.0	429.5	601.0	374.4
Non-productive	4.0	4.0	4.0	3.2	8.0	8.0
Total	673.0	419.7	650.0	432.7	609.0	382.4

ACQUISITION, EXPLORATION AND DEVELOPMENT CAPITAL EXPENDITURES

The following table summarizes our acquisition, exploration and development expenditures:

	United States	Canada	Consolidated
		(In thousands)	
2008			
Proved acreage	$ 787,172	$ -	$ 787,172
Unproved acreage	484,770	54,048	538,818
Development costs	836,032	68,629	904,661
Exploration costs	30,161	10,280	40,441
Total	$2,138,135	$132,957	$2,271,092
2007			
Proved acreage	$ -	$ -	$ -
Unproved acreage	17,031	31,448	48,479
Development costs	648,632	67,608	716,240
Exploration costs	75,862	11,953	87,815
Total	$ 741,525	$111,009	$ 852,534
2006			
Proved acreage	$ -	$ -	$ -
Unproved acreage	32,048	1,574	33,622
Development costs	121,104	82,378	203,482
Exploration costs	280,438	27,197	307,635
Total	$ 433,590	$111,149	$ 544,739

PRODUCTIVE OIL AND GAS WELLS

The following table summarizes productive wells:

	As of December 31, 2008			
	Natural Gas		Crude Oil	
	Gross	Net	Gross	Net
United States	664.0	587.5	222.0	218.4
Canada	2,635.0	1,237.7	3.0	0.1
Total	3,299.0	1,825.2	225.0	218.5

OIL AND GAS ACREAGE

Our principal natural gas and crude oil properties consist of non-producing and producing oil and gas leases and mineral acreage, including reserves of natural gas and crude 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 have not been drilled or completed to a point that would permit the production of commercial reserves, regardless of whether or not 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, 2008			
	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Texas	76,333	66,887	683,637	599,727
Other	91,759	82,235	256,433	205,474
United States	168,092	149,122	940,070	805,201
Canada	400,564	248,136	288,497	229,325
Total	568,656	397,258	1,228,567	1,034,526

The following table summarizes information regarding the total number of net undeveloped acres as of December 31, 2008:

		2009 Expirations		2010 Expirations		2011 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
Texas	599,727	88,752	22,549	400,552	21,842	62,778	1,095
Other U.S.	205,474	19,721	6,457	30,860	128	26,838	5,611
Canada	229,325	24,470	570	23,230	-	63,529	-
Totals	1,034,526	132,943	29,576	454,642	21,970	153,145	6,706

All of the acreage scheduled to expire can be held through drilling operations. We believe that we have the ability to retain all of the expiring acreage that we feel is prospective of economic production either through drilling activities or through the exercise of extension options.

MARKETING

We sell natural gas, NGLs and crude 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 2008, Targa and Total Gas and Power, the largest purchasers of our products, accounted for approximately 17% and 10% of our total natural gas, NGL and crude oil revenue, respectively.

COMPETITION

Depending upon economic and competitive factors, we may encounter difficulty in acquiring oil and natural gas leases and properties, marketing natural gas and crude oil, securing personnel and otherwise conducting our operations. Our competitors may include the major oil and natural gas companies as well as numerous independents and individual proprietors.

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, natural gas and crude oil production and related operations are, or have been, subject to price controls, taxes and other laws and regulations relating to the industry. Failure to comply with such laws and regulations can result in substantial penalties. 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.

ENVIRONMENTAL MATTERS

Our exploration, development, production, pipeline gathering and processing operations for natural gas and crude oil are subject to stringent U.S. and Canadian federal, state, provincial and local laws governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency ("EPA"), issue regulations to implement and enforce such laws, and compliance is often difficult and costly. Failure to comply may result in substantial costs and expenses, including possible civil and criminal penalties. These laws and regulations may:

- require the acquisition of a permit before drilling commences;
- restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production, processing and pipeline gathering activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, frontier and other protected areas;
- require remedial action to prevent pollution from former operations such as plugging abandoned wells; and
- impose substantial liabilities for pollution resulting from operations.

In addition, these laws, rules and regulations may restrict the rate of natural gas and crude oil production below the rate that would otherwise exist. The regulatory burden on the industry increases the cost of doing business and consequently affects our profitability. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, disposal or clean-up requirements could adversely affect our financial position, results of operations and cash flows. While we believe that we are in substantial compliance with current applicable environmental laws and regulations, and we have not experienced any materially adverse effect from compliance with these environmental requirements, we cannot assure you that this will continue in the future.

The U.S. Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the present or past owners or operators of the disposal site or sites where the release occurred and the companies that transported or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment. Furthermore, although petroleum, including natural gas and crude oil, is exempt from CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as "hazardous substances" under CERCLA and thus such wastes may become subject to liability and regulation under CERCLA. State initiatives to further regulate the disposal of crude oil and natural gas wastes are also pending in certain states, and these various initiatives could have adverse impacts on us.

Stricter standards in environmental legislation may be imposed on the industry in the future. For instance, legislation has been proposed in the U.S. Congress from time to time that would reclassify certain exploration and production by-products as "hazardous wastes" and make them subject to more stringent handling, disposal and clean-up restrictions. Compliance with environmental requirements generally could have a materially adverse effect upon our financial position, results of operations and cash flows. Although we have not experienced any materially adverse effect from compliance with environmental requirements, we cannot assure you that this will continue in the future.

The U.S. Federal Water Pollution Control Act ("FWPCA") imposes restrictions and strict controls regarding the discharge of produced waters and other petroleum wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters. The FWPCA and analogous state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of crude oil and other hazardous substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. Federal effluent limitation guidelines prohibit the discharge of produced water and sand, and some other substances related to the natural gas and crude oil industry, into coastal waters. Although the costs to comply with zero discharge mandated under federal or state law may be significant, the entire industry will experience similar costs and we believe that these costs will not have a materially adverse impact on our financial condition and results of operations. Some oil and natural gas exploration and production facilities are required to obtain permits for their storm water discharges. Costs may be incurred in connection with treatment of wastewater or developing storm water pollution prevention plans.

The U.S. Resource Conservation and Recovery Act ("RCRA"), generally does not regulate most wastes generated by the exploration and production of natural gas and crude oil. RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy." However, these wastes may be regulated by the EPA or state agencies as solid waste. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, are regulated as hazardous wastes. Although the costs of managing solid hazardous waste may be significant, we do not expect to experience more burdensome costs than would be borne by similarly situated companies in the industry.

In addition, the U.S. Oil Pollution Act ("OPA") requires owners and operators of facilities that could be the source of an oil spill into "waters of the United States," a term defined to include rivers, creeks, wetlands and coastal waters, to adopt and implement plans and procedures to prevent any spill of oil into any waters of the United States. OPA also requires affected facility owners and operators to demonstrate that they have at least $35 million in financial resources to pay for the costs of cleaning up an oil spill and compensating any parties damaged by an oil spill. Substantial civil and criminal fines and penalties can be imposed for violations of OPA and other environmental statutes.

In Canada, the oil and natural gas industry is currently subject to environmental regulations pursuant to municipal, provincial, and federal legislation. Environmental legislation provides for restrictions and prohibitions on industry development and environmental impact including releases or emissions of various substances associated with industry activities. In addition, legislation requires that well and facility sites be constructed, operated, abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in suspension of activities and substantial cash expenses, including possible fines and penalties.

In Alberta, environmental compliance is regulated by Alberta Environment. Industry specific regulations including some areas of environmental activities are governed and enforced by the Energy Resource Conservation Board.

In British Columbia, environmental compliance is regulated by The Ministry of the Environment. Industry specific regulations including some areas of environmental activities are governed and enforced by the Oil and Gas Commission.

AVAILABILITY OF REPORTS AND CORPORATE GOVERNANCE DOCUMENTS

We make available free of charge 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." Stockholders may request copies of these documents by writing to the Investor Relations Department at 777 West Rosedale Street, Fort Worth, Texas 76104.

EMPLOYEES

As of January 30, 2009, we had 615 full-time employees, none of whom have collective bargaining agreements.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following information is provided with respect to our executive officers as of February 10, 2009.

Name	Age	Position(s)
Thomas F. Darden	55	Director, Chairman of the Board
Glenn Darden	53	Director, President and Chief Executive Officer
Anne Darden Self	51	Director, Vice President - Human Resources
Jeff Cook	52	Executive Vice President - Operations
Philip W. Cook	47	Senior Vice President - Chief Financial Officer
John C. Cirone	59	Senior Vice President, General Counsel and Secretary
John C. Regan	39	Vice President, Controller and Chief Accounting Officer
Robert N. Wagner	45	Vice President - Reservoir Engineering

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. P. 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 was elected as a director of Quicksilver Gas Services GP LLC in July 2007. 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 was elected as a director of Quicksilver Gas Services GP LLC in March 2007. 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).

ANNE DARDEN SELF has served on our Board of Directors since September 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 Senior Vice President - Chief Financial Officer in October 2005. From October 2004 until October 2005, Mr. Cook served as President and Chief Financial Officer of EcoProduct Solutions, a private chemical company. From August 2001 until September 2004, he served as Vice President and

Chief Financial Officer of PPI Technology Services, an oilfield service company. From August 1993 to July 2001, he served in various capacities, including Vice President and Controller, Vice President and Chief Information Officer and Vice President of Audit, of Burlington Resources Inc. (subsequently merged with ConocoPhillips), an independent oil and gas company engaged in exploration, development, production and marketing.

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

JOHN C. REGAN became our Vice President, Controller and Chief Accounting Officer in September 2007. He is a Certified Public Accountant with more than 15 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.

ROBERT N. WAGNER became our Vice President - Reservoir Engineering in December 2002, after serving as our Vice President - Engineering since July 1999. From January 1999 to July 1999, he was our manager of eastern region field operations. From November 1995 to January 1999, Mr. Wagner held the position of District Engineer with Mercury. Prior to 1995, he was with Mesa, Inc. (subsequently merged with Parker and Parsley) for more than eight years and served as both drilling engineer and production engineer.

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.

Natural gas and crude oil prices fluctuate widely, and low prices could have a material adverse impact on our business.

Our revenue, profitability and future growth depend in part on prevailing natural gas, NGL and crude oil prices. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under our Senior Secured Credit Facility is subject to periodic redetermination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas, NGLs and crude oil that we can economically produce.

While prices for natural gas and crude oil may be favorable at any point in time, they fluctuate widely, particularly as evidenced by price movements in the latter half of 2008. Among the factors that can cause these fluctuations are:

- domestic and foreign demand for natural gas and crude oil;
- the level of domestic and foreign natural gas and crude oil supplies;
- the price and availability of alternative fuels;
- weather conditions;
- domestic and foreign governmental regulations;
- impact of trade organizations, such as OPEC;
- political conditions in oil and natural gas producing regions; and
- worldwide economic conditions.

Due to the volatility of natural gas and crude oil prices and our inability to control the factors that influence them, we cannot predict future pricing levels.

If natural gas or crude oil prices decrease, our exploration and development efforts are unsuccessful or our costs increase substantially, we may be required to recognize impairment expenses on our oil and gas properties.

We employ the full cost method of accounting for our oil and gas properties, whereby all costs associated with acquiring, exploring for, and developing natural gas and crude oil reserves are capitalized and accumulated in separate country cost centers. These capitalized costs are amortized based on production from the reserves for each country cost center. Each capitalized cost pool cannot exceed the net present value of the underlying natural gas, NGL and crude oil reserves. Impairment to the carrying value of our oil and gas properties was recognized in the fourth quarter of 2008 and could occur again in the future if natural gas, NGL or crude oil prices at a reporting period end result in significantly decreased value of our reserves. Increased operating and capitalized costs without incremental increases in natural gas and crude oil reserves could also trigger impairment based on reduced value of our reserves. In the event of impairment, we recognize expense in the amount of the impairment, which could be material and could adversely affect our results of operations and financial condition.

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

The process of estimating natural gas, NGL and crude oil reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves disclosed in this annual report.

In order to prepare these estimates, we and independent reserve engineers engaged by us must project production rates and timing of development expenditures. 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. The process also requires economic assumptions with respect to natural gas and crude oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of natural gas, NGL and crude oil reserves are inherently imprecise.

Actual future production, natural gas, NGL and crude oil prices and revenue, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and crude oil reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves disclosed in this annual report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing petroleum prices and other factors, which may be beyond our control.

At December 31, 2008, approximately 37% of our estimated proved reserves were undeveloped. Undeveloped reserves, by their nature, are less certain than comparable developed reserves. Recovery of undeveloped reserves requires additional capital expenditures and successful drilling and completion operations. Our reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of our reserves and the costs associated with them in accordance with industry standards, there is risk that the estimated costs are inaccurate, that development will not occur as scheduled or that actual results will not be as estimated.

The present value of future net cash flows disclosed in Item 8 of this annual report is not necessarily the fair value of our estimated proved natural gas and crude oil reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are based on prices and costs as of period end. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by natural gas, NGL and crude oil purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of natural gas and crude oil 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 required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, 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 natural gas industry in general will affect the appropriateness of the 10% discount factor in arriving at the reserves' actual fair value.

Our production is concentrated in a small number of geographic areas.

Approximately 75% of our 2008 production was from Texas and approximately 24% was from Alberta, Canada. Because of our concentration in these geographic areas, any regional events that increase costs, reduce availability of equipment or supplies, reduce demand or limit production, including weather and natural disasters, may impact us more than if our operations were more geographically diversified.

Our Canadian operations present unique risks and uncertainties, different from or in addition to those we face in our domestic 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, changes in laws and policies governing operations of foreign-based companies, currency restrictions and exchange rate fluctuations. Laws and policies of the United States affecting foreign trade and taxation may also adversely affect our Canadian operations.

We may have difficulty financing our planned growth.

We have experienced capital expenditure and working capital needs, particularly as a result of our property acquisition and drilling activities. For 2009, we plan to operate our capital program within our operating cash flows. However, in the future, we may require additional financing above the level of cash generated by our operations to fund our growth. If revenue decreases as a result of lower petroleum prices or otherwise, our ability to expend the capital necessary to replace our reserves or to maintain production of current levels may be limited, resulting in a decrease in production over time. If our cash flow from operations is not sufficient to satisfy our capital expenditure requirements, we cannot be certain that additional financing will be available to us on acceptable terms or at all. In the event 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.

We are vulnerable to operational hazards, transportation dependencies, regulatory risks and other uninsured risks associated with our activities.

The oil and natural gas business involves operating hazards such as well blowouts, explosions, uncontrollable flows of crude 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. Also, the availability of a ready market for our natural gas and crude oil production depends on the proximity of reserves to, and the capacity of, natural gas and crude oil gathering systems, treatment plants, pipelines and trucking or terminal facilities.

U.S. and Canadian federal, state and provincial regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand and general economic conditions could adversely affect our ability to produce and market our natural gas, NGLs and crude oil. In addition, we may be liable for environmental damage caused by previous owners of properties purchased or leased by us.

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. Generally, environmental risks are not fully insurable. The occurrence of an event that is not covered, or not fully covered, by insurance could have a material adverse effect on our business, financial condition and results of operations.

The failure to replace our reserves could adversely affect our production and cash flows.

Our future success depends upon our ability to find, develop or acquire additional reserves that are economically recoverable. Our proved reserves will generally decline as reserves are produced, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves. In order to increase reserves and production, we must continue our development drilling and recompletion programs or undertake other replacement activities. Our current strategy is to maintain our focus on low-cost operations while increasing our reserve base and production through exploration and development of our existing properties. Our planned exploration or development projects or any acquisition activities that we may undertake might not result in meaningful additional reserves and we might not have continuing success drilling productive wells. Furthermore, while our revenue may increase if prevailing petroleum prices increase materially, our finding costs also could increase.

We have risk through our investment in BBEP.

We own a 41% limited partner interest in BBEP from which we expect to receive distributions. We have no management oversight over BBEP, its financial condition, its operating results or its financial reporting process and are subject to the risks associated with BBEP's business and operations. Moreover, the management of BBEP has discretion over the amount, if any, that they distribute to unitholders.

The nature of our ownership interest in a publicly-traded entity subjects us to market risks associated with most ownership interests traded on a public exchange. Sales of substantial amounts of BBEP limited partner units, or a perception that such sales could occur, could adversely affect the market price of our BBEP limited partner units, which could result in an impairment to the value of our limited partner interest in BBEP.

We have risk through our ownership of KGS.

Through our ownership interest in KGS, we share in KGS' results of operations and may be entitled to distributions from KGS. Accordingly, we have diminished control over assets owned by KGS and assets which KGS has a right to acquire. We are also subject to the risks associated with KGS' business and operations, including, but not limited to:

- changes in general economic conditions;
- fluctuations in natural gas prices;
- failure or delays in us and third parties achieving expected production from natural gas projects;
- competitive conditions in the midstream industry;
- actions taken on non-performance by third parties, including suppliers, contractors, operators, processors, transporters and customers;
- changes in the availability and cost of capital;
- operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- construction costs or capital expenditures exceeding estimated or budgeted amounts;
- the effects of existing and future laws and governmental regulations;
- the effects of future litigation; and
- other factors discussed in KGS' Annual Report on Form 10-K and as are or may be detailed from time to time in KGS' public announcements and other filings with the SEC.

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

We deliver our Canadian production to market primarily by either the TransCanada or ATCO systems. We have no influence over the operation of these facilities and must depend upon their owners to minimize any loss of processing and transportation capacity.

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 have an adverse effect on us.

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 natural gas companies for property acquisitions. We also compete 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. In addition, larger competitors may be able to absorb the burden of any changes in federal, state, provincial and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for exploratory prospects and productive natural gas and crude oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for natural gas and crude oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to complete transactions in this highly competitive environment. Furthermore, the oil and natural gas industry competes with other industries in supplying the energy and fuel needs of industrial, commercial, and other consumers.

Hedging our production may result in losses or limit our ability to benefit from price increases.

To reduce our exposure to petroleum price fluctuations, we have entered into financial hedging arrangements which may limit the benefit we would receive from increases in petroleum prices. These hedging 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 other parties to the hedging contracts could fail to perform their contractual obligations.

The result of natural gas market prices exceeding collar ceilings requires us to make monthly cash payments. If we choose not to engage in hedging arrangements in the future, we could be more affected by changes in natural gas, NGL and crude oil 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 and our results of operations.

At higher natural gas, NGL and oil prices, increased demand results in increased costs for drilling equipment, crews and associated supplies, equipment and services. We cannot be certain that we could obtain necessary drilling equipment and supplies in a timely manner or on satisfactory terms, and we may experience shortages of, or material increases in the cost of, drilling equipment, crews and associated supplies, equipment and services during periods of high petroleum prices. Any such delays and price increases could adversely affect our ability to pursue our drilling program and our results of operations.

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

Natural gas, NGL and crude oil 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;
- environmental protection; 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 crude oil wells below actual production capacity to conserve supplies of natural gas and crude oil. We also are subject to changing and extensive tax laws, the effects of which cannot be predicted.

The development, production, handling, storage, transportation and disposal of natural gas and crude oil, by-products and other substances and materials produced or used in connection with our operations are also subject to laws and regulations primarily relating to protection of human health and the environment. The discharge of natural gas, crude oil or pollutants into the air, soil or water may give rise to significant liabilities on our part to the government and third parties and may result in the assessment of civil or criminal penalties or require us to incur substantial costs of remediation.

Legal 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.

The risks associated with our debt could adversely affect our business, financial condition and results of operations, and such risk could increase if we incur more debt.

Subject to the limits contained in our various loan agreements and indentures, we may incur additional debt. Our ability to borrow under our Senior Secured Credit Facility is subject to the quantity and value of our proved reserves and other assets, including our units owned in BBEP. If we incur additional debt or fail to increase the quantity and value of our proved reserves, the risks that we now face as a result of our indebtedness could intensify.

We have demands on our cash resources in addition to interest expense, including operating expenses, principal payments under our debt and funding of our capital expenditures. Our level of debt relative to our proved reserves and these significant demands on our cash resources could have important effects on our business and on the value of our securities. For example, they 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 natural 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 default in the event of a failure to comply with covenants contained in our debt agreements, which, if not cured or waived, could adversely affect our financial condition or results of operations.

Our ability to pay principal and interest on our long-term debt and to satisfy our other liabilities will depend upon our future performance and our ability to refinance our debt as it becomes due. Our future operating performance and ability to refinance will be affected by economic and capital markets conditions then prevailing and other factors which may be beyond our control. If we are unable to service our debt and fund our operating costs, 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; or
- restructuring or refinancing debt.

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 the holders of our securities to experience a partial or total loss of their investment in us.

Our debt agreements restrict our ability to engage in certain activities.

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, also require the maintenance of financial covenants that are more fully described in Note 14 to the consolidated financial statements in Item 8 of this annual report. Our ability to satisfy these covenants may be affected by events beyond our control, and we may be unable to satisfy such covenants and requirements in the future. In addition, our ability to borrow under our Senior Secured Credit Facility is dependent upon the quantity and value of our proved reserves.

The covenants contained in the agreements governing our debt may affect our flexibility in planning for, and reacting to, changes in business conditions. In addition, a breach of the restrictive or financial covenants in our debt agreements could result in an event of default. Upon the occurrence of such an event of default, the applicable creditors could, subject to the terms and conditions of the applicable agreement, elect to declare the outstanding principal of that debt, together with 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, there can be no assurance that our assets would be sufficient to repay such debt in full. The above restrictions could limit our ability to obtain future financing and may prevent us from taking advantage of attractive business opportunities.

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.

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

Members of the Darden family, together with entities controlled by them, beneficially own approximately 30% of our common stock as of December 31, 2008. 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.

A large number of our outstanding shares and shares to be issued upon conversion of our outstanding convertible debentures or exercise of our outstanding options may be sold into the market in the future, which could cause the market price of our common stock to drop significantly, even if our business is performing well.

Our shares that are eligible for future sale may adversely affect the price of our common stock. There were more than 167 million shares of our common stock outstanding at December 31, 2008. Approximately 116 million of these shares are freely tradable without substantial restriction or the requirement of future registration under the Securities Act. In addition, when the necessary restrictions for our contingently convertible debentures are satisfied and become convertible at the holders' option, based on the conversion rate, an aggregate of 9,816,270 shares of our common stock could be issued. We also had 1,103,336 options outstanding to purchase shares of our common stock at December 31, 2008 as detailed in Note 20 to the consolidated financial statements in Item 8 of this annual report.

Sales of substantial amounts of common stock, or a perception that such sales could occur, and the existence of conversion and option rights to acquire shares of common stock at prices that may be below the then current market price of the common stock, could adversely affect the market price of our common stock and could impair our ability to raise capital through the sale of our equity securities.

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.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 2. Properties

A detailed description of our significant properties and associated 2008 developments can be found in Item 1 of this annual report, which is incorporated herein by reference.

ITEM 3. Legal Proceedings

Information required with respect to this item is set forth in Note 17 to the consolidated financial statements included in Item 8 of this annual report, which is incorporated herein by reference.

ITEM 4. Submission of Matters to a Vote of Security Holders

There were no matters submitted to a stockholder vote during the fourth quarter of 2008.

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 sales prices of our common stock for the periods indicated below.

	HIGH	LOW
2008		
Fourth Quarter	$ 20.74	$ 3.74
Third Quarter	40.70	17.13
Second Quarter	44.98	34.96
First Quarter	38.72	24.28
2007[(1)]		
Fourth Quarter	$ 30.58	$ 23.44
Third Quarter	24.28	18.85
Second Quarter	24.77	19.74
First Quarter	20.42	16.48

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

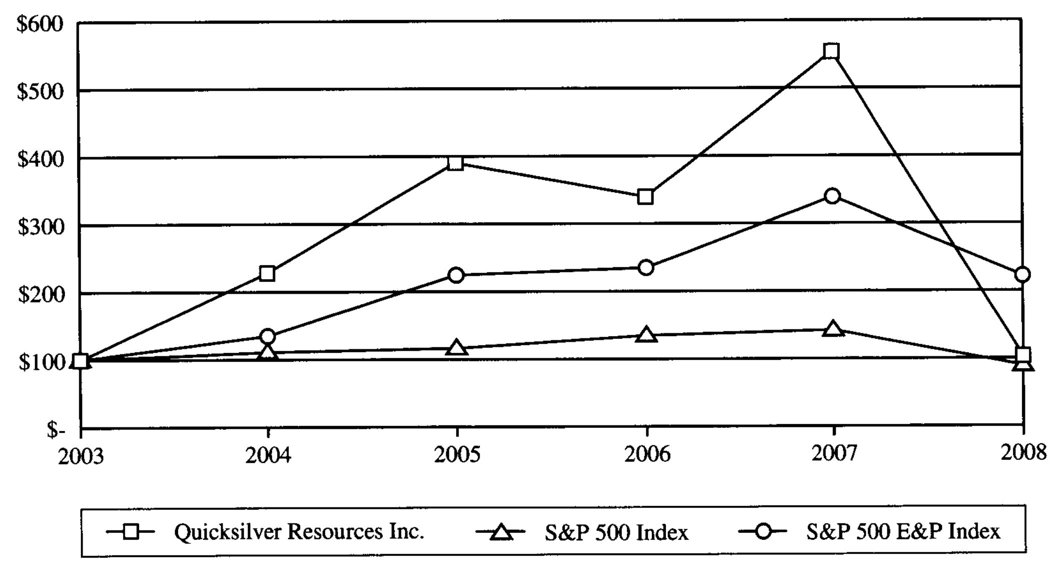
As of January 31, 2009, there were approximately 845 common stockholders of record.

We have not paid 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 prohibit payments of dividends.

Performance Graph

The following performance graph compares the cumulative total stockholder return on Quicksilver common stock with the Standard & Poor's 500 Stock Index (the "S&P 500 Index") and the Standard & Poor's 500 Exploration and Production Index (the "S&P 500 E&P Index") for the period from December 31, 2003 to December 31, 2008, assuming an initial investment of $100 and the reinvestment of all dividends, if any.

Comparison of Cumulative Five Year Total Return



Issuer Purchases of Equity Securities

The following table summarizes the Company's repurchases of its common stock during the quarter ended December 31, 2008.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan[3]	Maximum Number of Shares that May Yet Be Purchased Under the Plan[3]
October 2008[1]	1,885,600	$10.55	-	-
November 2008	-	$ -	-	-
December 2008[2]	573	$ 4.44	-	-
Total	1,886,173	$10.55	-	-

(1) Represents shares of common stock purchased from Quicksilver Energy L.P., an entity owned by members of the Darden family

(2) 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

(3) 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,				
	2008[(2)]	2007[(3)]	2006	2005	2004
	(In thousands, except for per share data and ratios)				
Operating Results Information					
Total revenues	$ 800,641	$ 561,258	$ 390,362	$ 310,448	$ 179,729
Operating income (loss)	(249,697)	803,581	174,196	149,129	60,693
Income (loss) before income taxes and minority interest	(578,489)	736,941	131,960	127,974	45,446
Net income (loss)	(373,994)	479,378	93,719	87,434	31,272
Diluted earnings (loss) per common share[(1)]	$ (2.31)	$ 2.86	$ 0.58	$ 0.54	$ 0.21
Dividends paid per share	—	—	—	—	—
Cash provided by operating activities	$ 456,566	$ 319,104	$ 242,186	$ 140,242	$ 84,847
Capital expenditures	2,279,927	1,020,684	619,061	331,805	215,106
Financial Condition Information					
Property, plant and equipment - net	$ 3,797,715	$ 2,142,346	$ 1,679,280	$ 1,112,002	$ 802,610
Total assets	4,500,571	2,775,846	1,882,912	1,243,094	888,334
Long-term debt	2,605,025	813,817	919,517	506,039	399,134
Long-term obligations excluding debt	47,715	34,473	25,058	20,891	17,967
Stockholders' equity	1,094,709	1,068,355	575,666	383,615	304,276

(1) Per share amounts have been adjusted to reflect a three-for-two stock split effected in the form of a stock dividend in June 2005 and a two-for-one stock split effected in the form of a stock dividend in January 2008

(2) 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 pretax income attributable to the Company's proportionate ownership of BBEP and a pretax charge of $320.4 million for impairment of that investment

(3) Operating income and net income for 2007 include a gain of $628.7 million recognized from the divestiture of the Company's Northeast Operations and a charge of $63.5 million associated with the Michigan Sales Contract (See Notes 4 and 5 to the consolidated financial statements in Item 8 of this annual report)

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 the reader 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. We conduct our operations in two segments: (1) our more dominant exploration and production segment, and (2) our significantly smaller gathering and processing segment. Except as otherwise specifically noted, or as the context requires otherwise, and except to the extent that differences between these segments or our geographic segments are material to an understanding of our business taken as a whole, we present this MD&A on a consolidated basis.

Our MD&A includes the following sections:

- *Overview* - a general description of our business; the value drivers of our business; measurements; and opportunities, challenges and risks.
- *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 a Fort Worth, Texas-based independent oil and gas company engaged in the acquisition, exploration, exploitation, development and production of natural gas, NGLs, and crude oil. We focus primarily on unconventional reservoirs where hydrocarbons may be found in challenging geological conditions such as fractured shales, coal beds and tight sands. We generate revenue, income and cash flows by producing and selling natural gas, NGLs and crude oil. Our production generates earnings and cash flow that allow us to conduct acquisition, exploration, exploitation, development and production activities to replace the reserves that we produce.

At December 31, 2008, approximately 99% of our proved reserves were natural gas and NGLs. Consistent with one of our business strategies, we have developed and applied the expertise gained in developing our now divested Northeast Operations to our projects in Alberta, Canada and our Barnett Shale interests in Texas. Our Texas and Alberta reserves made up approximately 84% and 15%, respectively, of our proved reserves at December 31, 2008. Our acreage in the Horn River Basin in British Columbia will provide additional opportunity for further application of this expertise.

For 2009, we plan to continue our focus on the development and exploitation of our properties in Texas and Alberta and to begin exploration in the Horn River Basin. We have allocated \$400 million of our 2009 consolidated capital budget of \$600 million for drilling and completion activities. Approximately \$330 million is allocated to projects in Texas and approximately \$57 million is allocated to our Canadian projects. Approximately \$155 million of the 2009 capital budget has been allocated to construction of natural gas processing and gathering assets, including \$35 million to be funded directly by KGS.

Our Company focuses on three key value drivers:

- reserve growth;
- production growth; and
- maximizing the Company's operating cash flows.

Our reserve growth relies on our ability to apply our technical and operational expertise in our core operating areas to develop, exploit and explore unconventional natural gas reservoirs. We strive to increase reserves and production through aggressive management of operations and through relatively low-risk development and exploitation 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 and exploit unconventional natural gas reservoirs which align our technical and operational expertise.

Our core operating areas and the acreage that we hold are well suited for production increases through development and exploitation drilling. We perform workover and infrastructure projects to reduce ongoing operating costs and increase current and future production rates. We regularly review our operated properties to determine if steps can be taken to profitably increase reserves and production.

In evaluating the result of our efforts, we consider the capital efficiency of our drilling program and also measure the following key indicators: reserve growth; production volumes; cash flow from operating activities; and earnings per share.

	Years Ended December 31,		
	2008	2007	2006
Organic reserve growth[1]	29%	59%	46%
Production volumes (Bcfe)	96.2	77.9	61.3
Cash flow from operating activities (in millions)	$ 456.6	$ 319.1	$ 242.2
Diluted earnings (loss) per share[2]	$ (2.31)	$ 2.86	$ 0.58

(1) Organic growth excludes reserves acquired or divested from beginning and ending reserves and from production. This ratio is calculated by subtracting adjusted beginning of the year proved reserves from adjusted end of the year proved reserves and dividing by adjusted beginning of the year proved reserves. Adjusted beginning of the year reserves are calculated by deducting sold reserves and adjusted current year production from beginning of the year reserves. Adjusted current year production excludes production from purchased reserves. Adjusted end of the year reserves are calculated by deducting purchased reserves from end of the year reserves.

(2) Operating loss for 2008 includes a pretax charge of $633.5 million for impairment associated with our U.S. oil and gas properties. Net loss also includes $93.3 million of pretax income attributable to the Company's proportionate ownership of BBEP and a pretax charge of $320.4 million for impairment of that investment.

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 crude oil production is among the several risks that we face. We seek to manage this risk by entering into financial hedges. We have mitigated the downside risk of adverse price movements through the use of derivatives but, in doing so, have also limited our ability to benefit from favorable price movements. This commodity price strategy enhances our ability to execute our development, exploitation and exploration programs, meet debt service requirements and pursue acquisition opportunities even in periods of price volatility.

RESULTS OF OPERATIONS

Revenue

Natural Gas, NGL and Crude Oil

Production Revenue:

	Natural Gas			NGL			Oil and Condensate			Total		
	2008	2007	2006	2008	2007	2006	2008	2007	2006	2008	2007	2006
						(In millions)						
Texas	$ 371.1	$ 121.6	$ 63.0	$ 198.1	$ 106.7	$ 22.8	$ 30.4	$ 9.2	$ 5.0	$ 599.6	$ 237.5	$ 90.8
Northeast Operations	—	100.8	137.5	—	4.5	5.4	—	18.6	21.2	—	123.9	164.1
Other U.S.	0.6	0.3	0.8	0.8	0.6	0.5	14.8	10.2	9.5	16.2	11.1	10.8
Hedging	(2.2)	26.3	5.4	(8.6)	(5.2)	—	(7.1)	(0.7)	(0.5)	(17.9)	20.4	4.9
Total U.S.	369.5	249.0	206.7	190.3	106.6	28.7	38.1	37.3	35.2	597.9	392.9	270.6
Canada	182.7	126.4	106.0	0.4	0.2	0.3	—	—	—	183.1	126.6	106.3
Hedging	(0.2)	25.6	9.7	—	—	—	—	—	—	(0.2)	25.6	9.7
Total Canada	182.5	152.0	115.7	0.4	0.2	0.3	—	—	—	182.9	152.2	116.0
Total	$ 552.0	$ 401.0	$ 322.4	$ 190.7	$ 106.8	$ 29.0	$ 38.1	$ 37.3	$ 35.2	$ 780.8	$ 545.1	$ 386.6

Average Daily Production Volumes:

	Natural Gas			NGL			Oil and Condensate			Equivalent Total		
	2008	2007	2006	2008	2007	2006	2008	2007	2006	2008	2007	2006
		(MMcfd)			(Bbld)			(Bbld)			(MMcfed)	
Texas	122.8	50.1	23.9	11,425	6,395	1,579	873	349	215	196.6	90.6	34.7
Northeast Operations	—	56.1	71.7	—	331	419	—	799	930	—	62.9	79.8
Other U.S.	0.3	0.3	0.3	36	29	31	447	452	463	3.2	3.2	3.3
Total U.S.	123.1	106.5	95.9	11,461	6,755	2,029	1,320	1,600	1,608	199.8	156.7	117.8
Canada	63.0	56.8	50.0	3	13	14	—	—	—	63.0	56.9	50.0
Total	186.1	163.3	145.9	11,464	6,768	2,043	1,320	1,600	1,608	262.8	213.6	167.8

Average Realized Prices:

	Natural Gas			NGL			Oil and Condensate			Equivalent Total		
	2008	2007	2006	2008	2007	2006	2008	2007	2006	2008	2007	2006
		(per Mcf)			(per Bbl)			(per Bbl)			(per Mcfe)	
Texas	$ 8.26	$ 6.65	$ 7.22	$ 47.38	$ 45.70	$ 39.56	$ 95.16	$ 72.37	$ 63.62	$ 8.33	$ 7.18	$ 7.18
Northeast Operations	—	4.92	5.25	—	37.36	35.27	—	63.81	62.33	—	5.40	5.63
Other U.S.	7.43	4.68	6.85	70.52	52.35	46.55	89.41	61.49	56.25	13.92	9.63	9.03
Hedging - U.S.	(0.05)	0.67	0.15	(14.72)	(1.19)	(0.77)	(2.06)	(2.10)	—	(0.25)	0.45	0.11
Total U.S.	$ 8.20	$ 6.40	$ 5.90	$ 45.39	$ 43.22	$ 38.78	$ 78.83	$ 63.87	$ 59.99	$ 8.18	$ 6.87	$ 6.29
Canada	7.92	6.10	5.82	325.52	48.02	49.03	—	—	—	7.94	6.10	5.82
Hedging - Canada	(0.01)	1.23	0.53	—	—	—	—	—	—	(0.01)	1.23	0.53
Total Canada	$ 7.91	$ 7.33	$ 6.35	$ 325.52	$ 48.02	$ 49.03	$ —	$ —	$ —	$ 7.93	$ 7.33	$ 6.35
Total	$ 8.10	$ 6.73	$ 6.05	$ 45.44	$ 43.23	$ 38.85	$ 78.83	$ 63.87	$ 59.99	$ 8.12	$ 6.99	$ 6.31

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

	Natural Gas	NGL	Oil	Total
		(In thousands)		
Revenue for 2006	$ 322,357	$ 28,978	$ 35,205	$ 386,540
Volume changes	42,735	74,546	(171)	117,110
Price changes	35,897	3,263	2,279	41,439
Revenue for 2007	$ 400,989	$ 106,787	$ 37,313	$ 545,089
Volume changes	57,227	74,591	(6,463)	125,355
Price changes	93,830	9,288	7,226	110,344
Revenue for 2008	$ 552,046	$ 190,666	$ 38,076	$ 780,788

Our natural gas revenue for 2008 increased as a result of both a $1.37 per Mcf increase in realized prices and a 22.8 MMcfd increase in volumes as compared to 2007. Natural gas production in the

U.S. increased 78.5 MMcfd as a result of the impact of new wells placed into production partially offset by production declines for existing wells, primarily in the Fort Worth Basin. The November 2007 divestiture of our Northeast Operations reduced our natural gas production by 56.1 MMcfd and the Alliance Acquisition increased production by 17.0 MMcfd on an annualized basis. Additional wells on our Canadian interests increased production by 6.2 MMcfd from 2007.

NGL revenue for 2008 increased as a result of production increases and realized prices that were $2.21 per Bbl higher than 2007 NGL realized prices. Additional Texas natural gas production in the high-BTU area of the Barnett Shale and processing improvements during 2008 increased NGL volumes 5,030 Bbld when compared to 2007. Partially offsetting the Texas production and pricing increases was the absence of production due to the divestiture of the Northeast Operations.

Crude oil revenue for 2008 was higher than 2007 due to a $14.96 per Bbl increase in realized prices. Production increases of 524 Bbld from the Fort Worth Basin in 2008 partially offset the divested production from the Northeast Operations.

Our natural gas revenue for 2007 increased from 2006 as a result of both a $0.68 per Mcf increase in realized natural gas prices and a 17.4 MMcfd increase in volumes as compared to 2006. Natural gas revenue in the U.S. increased 10.6 MMcfd as a result of new wells placed into production, primarily in the Fort Worth Basin. The November 2007 divestiture of our Northeast Operations reduced our natural gas production as did natural production declines in this area. Additional wells on our Canadian interests increased production by 6.8 MMcfd from 2006.

NGL revenue for 2007 was almost three times higher than 2006, which primarily resulted from an incremental 1,724 MBbl increase in NGL production resulting from additional Texas natural gas production in the high-BTU area of the Barnett Shale during 2007. Also, more favorable pricing of $4.38 per Bbl contributed to the increase when compared to 2006 NGL revenue.

Crude oil revenue for 2007 was higher than 2006 due to a $3.88 per Bbl increase in realized prices. Fort Worth Basin production in 2007 increased to partially offset the impact of the divestiture of our Northeast Operations.

Other Revenue

Other revenue, consisting primarily of revenue from the processing, gathering and marketing of natural gas, was $19.9 million for 2008, an increase of $3.7 million compared with 2007. Throughput from third parties in our gathering and processing assets operated by KGS increased other revenue by $6.2 million. Partially offsetting the increase was the absence of $4.3 million of Canadian government grants for new drilling techniques we received in 2007.

Other revenue was $16.2 million for 2007, an increase of $12.3 million compared with 2006. This increase is primarily due to $5.1 million from higher throughput from third parties in our gathering and processing assets operated by KGS and $4.3 million more in Canadian government grants for new drilling techniques compared to 2006. Hedge ineffectiveness in 2007 also increased other revenue $1.0 million compared to 2006.

Operating Expenses

Oil and Gas Production Expenses

	Years Ended December 31,					
	2008		2007		2006	
	(In thousands, except per unit amounts)					
Texas		Per Mcfe		Per Mcfe		Per Mcfe
Cash expense	$ 92,096	$ 1.28	$ 53,726	$ 1.63	$ 24,692	$ 1.95
Equity compensation	1,130	0.02	339	0.01	105	0.01
	$ 93,226	$ 1.30	$ 54,065	$ 1.64	$ 24,797	$ 1.96
Northeast Operations						
Cash expense	$ —	$ —	$ 48,489	$ 2.11	$ 44,151	$ 1.51
Equity compensation	—	—	422	0.02	817	0.03
	$ —	$ —	$ 48,911	$ 2.13	$ 44,968	$ 1.54
Other U.S.						
Cash expense	$ 6,318	$ 5.35	$ 3,278	$ 2.97	$ 3,385	$ 2.89
Equity compensation	190	0.16	193	0.16	101	0.08
	$ 6,508	$ 5.51	$ 3,471	$ 3.13	$ 3,486	$ 2.97
Total U.S.						
Cash expense	$ 98,414	$ 1.34	$ 105,493	$ 1.84	$ 72,228	$ 1.68
Equity compensation	1,320	0.02	954	0.02	1,023	0.02
	$ 99,734	$ 1.36	$ 106,447	$ 1.86	$ 73,251	$ 1.70
Canada						
Cash expense	$ 33,781	$ 1.47	$ 28,415	$ 1.37	$ 20,862	$ 1.14
Equity compensation	2,146	0.09	1,969	0.09	1,063	0.06
	$ 35,927	$ 1.56	$ 30,384	$ 1.46	$ 21,925	$ 1.20
Total Company						
Cash expense	$ 132,195	$ 1.37	$ 133,908	$ 1.72	$ 93,090	$ 1.52
Equity compensation	3,466	0.04	2,923	0.04	2,086	0.03
	$ 135,661	$ 1.41	$ 136,831	$ 1.76	$ 95,176	$ 1.55

Oil and gas production expense for 2008 was almost unchanged from 2007. The absence of production expense of $48.9 million for the divested Northeast Operations was offset by the growth of our operations in the Fort Worth Basin and Canada that increased production expense $39.2 million and $5.5 million, respectively, as production volumes increased 117% and 11%, respectively, for 2008 as compared to 2007, as discussed previously.

Although oil and gas production expense for our Fort Worth Basin operations were $39.2 million higher for 2008, production expense per Mcfe decreased 21% to $1.30 per Mcfe when compared to 2007. The improvement in production expense on a Mcfe-basis was primarily the result of higher production levels, cost containment initiatives, new completion techniques used in our capital program and higher utilization of automation during 2008. Canadian production expense increased primarily as a result of the 11% increase in production volumes and an increase in personnel costs plus higher prevailing exchange rates during 2008.

Oil and gas production expense for 2007 increased by $41.7 million from 2006 levels, primarily due to costs associated with higher production levels. On a Mcfe-basis, our costs increased 14% compared to 2006 levels. Although overall costs increased in Texas, our production and number of producing properties increased while our cost per Mcfe of production decreased. Our 2007 production costs for the Northeast Operations reflected $6.3 million of employee severance cost associated with its divestiture. Northeast Operations unit costs were also impacted by production declines. The total cost increases reflect salary increases of $3.7 million associated with headcount increases. Canadian production expense increased $8.5 million due to an estimated $1.4 million for currency effects of the strengthening Canadian dollar, $1.2 million higher gathering and processing costs, $2.0 million in increased direct operating cost associated with new producing properties and more than $5.0 million of overhead costs, including higher salaries, stock-based compensation, incentive compensation and rent.

Production and Ad Valorem Taxes

	Years Ended December 31,					
	2008		2007		2006	
	(In thousands, except per unit amounts)					
Production and ad valorem taxes		Per Mcfe		Per Mcfe		Per Mcfe
U.S.	$ 14,060	$ 0.19	$ 13,005	$ 0.23	$ 13,948	$ 0.32
Canada	2,734	$ 0.12	3,137	$ 0.15	1,671	$ 0.09
Total production and ad valorem taxes	$ 16,794	$ 0.17	$ 16,142	$ 0.21	$ 15,619	$ 0.25

Production and ad valorem tax expense for 2008 increased slightly as compared to 2007. Production and ad valorem taxes increased $11.2 million due to the development of our Fort Worth Basin properties and increased production. This increase was nearly offset by the absence of production and ad valorem taxes associated with the divested Northeast Operations. We have historically experienced low severance tax expense for our Texas production as a result of exemptions and rate reductions for development of our acreage positions with wells deemed by the taxing authorities to be "high cost wells." We expect severance tax rates in Texas to increase in future quarters as fewer of our wells to be drilled in 2009 and beyond will qualify for severance tax exemptions and rate reductions because we expect our Fort Worth Basin drilling and completion costs to continue to decrease while the cost threshold for exemptions and rate reductions will increase.

Production and ad valorem tax expense for 2007 was relatively flat when compared to 2006 as a $2.1 million increase in ad valorem tax expense was mostly offset by a decrease in production taxes. Ad valorem tax expense increased primarily as a result of the growth in our Texas and Canadian property values associated with our 2007 capital expenditure program while production tax expense decreased as a result of a higher percentage of our production in Texas that is partially or fully exempted from production taxes.

Depletion, Depreciation and Accretion

	Years Ended December 31,					
	2008		2007		2006	
	(In thousands, except per unit amounts)					
		Per Mcfe		Per Mcfe		Per Mcfe
Depletion						
U.S.	$ 120,845	$ 1.65	$ 65,020	$ 1.14	$ 40,051	$ 0.93
Canada	40,337	1.75	34,666	1.67	25,618	1.40
Total depletion	161,182	1.68	99,686	1.28	65,669	1.07
Depreciation of other fixed assets:						
U.S.	$ 21,751	$ 0.30	$ 15,389	$ 0.27	$ 8,715	$ 0.20
Canada	3,780	0.16	4,115	0.20	3,129	0.17
Total depreciation	25,531	0.27	19,504	0.25	11,844	0.19
Accretion	1,483	0.01	1,507	0.02	1,287	0.02
Total depletion, depreciation and accretion	$ 188,196	$ 1.96	$ 120,697	$ 1.55	$ 78,800	$ 1.29

Higher depletion expense for 2008 resulted from a 31% increase in the depletion rate and a 23% increase in production volumes. Our 2008 depletion rate was impacted by the addition of the proved oil and gas properties obtained in the Alliance Acquisition as well as the capital costs incurred for proved reserves added from our existing properties and increases in estimated future capital expenditures. Depreciation expense for 2008 was $10.4 million higher than 2007 primarily due to additions of Fort Worth Basin field compression and KGS midstream infrastructure, partially offset by the absence of $4.1 million of depreciation expense associated with the divested Northeast Operations depreciable assets. We expect depreciation expense will further increase when KGS places its $110 million Corvette Plant into service in the first quarter of 2009 and we expect that depletion for our U.S. properties will be approximately $1.80 per Mcfe after the impairment recognized in the fourth quarter of 2008.

Depletion expense in 2007 increased from 2006 primarily as a result of a 27% increase in production. Our 2007 consolidated depletion rate increased $0.21 per Mcfe as a result of increased future development costs due in part to a higher percentage of undeveloped proved reserves for 2007 year-end as compared to 2006, and higher finding costs in 2007 in Texas. Depreciation expense for 2007 was $7.7 million higher than 2006 primarily resulting from increased capacity at our Cowtown Gas Plant, additions to our Cowtown Pipeline and new Canadian gas processing facilities.

Impairment of Oil and Gas Properties

We recognized a noncash pretax charge of $633.5 million ($411.8 million after tax) for impairment related to our U.S. oil and gas properties in December 2008. As required under full cost accounting rules, we performed a ceiling test by comparing the book value of our oil and gas properties, net of related deferred tax liability and asset retirement obligations, to the year-end ceiling limitation, which is the after-tax value of the future net cash flows from proved oil and gas reserves, including the effect of hedges. As also required under full cost accounting rules prescribed by the SEC, the ceiling amount was based upon year-end prices and costs, discounted at 10% per year. Under these rules, management has little ability to influence the ceiling amounts with respect to such factors as pricing, discount rate, cost structure and timing. Consequently, the ceiling amount is not necessarily indicative of the fair value of our oil and gas properties, which could have a wide range of potential fair values. Included below is an alternate valuation of our oil and gas reserves that supplements the ceiling amount and which management believes is more indicative of our oil and gas properties' fair value as it incorporates the valuation techniques we employ in making investment decisions.

The alternate value presented below would have, if permitted in place of the ceiling amount, eliminated any recognition of impairment during 2008. This valuation was calculated in the same manner as the scenario used in the ceiling test, except for the following changes:

- the forward strip prices on December 31, 2008, which featured future price increases and more appropriately reflect expected future realized prices, were used in place of year-end prices held constant;
- production expense was adjusted to reflect actual consolidated oil and gas production expenses; and,
- income tax considerations are excluded from the analysis although they are required for the ceiling test computation.

Management's alternate pretax valuation related to its proved oil and gas reserves at December 31, 2008 as described above was as follows:

	United States	Canada	Total
		(In thousands)	
Future revenues	$ 13,047,702	$ 2,012,958	$ 15,060,660
Future production costs	(4,300,591)	(550,345)	(4,850,936)
Future development costs	(1,195,503)	(112,330)	(1,307,833)
Future net pretax cash flows	7,551,608	1,350,283	8,901,891
10% discount	(4,188,201)	(721,623)	(4,909,824)
Management's estimate of pretax discounted future cash flows relating to proved reserves	$ 3,363,407	$ 628,660	$ 3,992,067

General and Administrative Expense

	Years Ended December 31,					
	2008		2007		2006	
	(In thousands, except per unit amounts)					
General and administrative expense		Per Mcfe		Per Mcfe		Per Mcfe
Cash expense	$ 49,982	$ 0.52	$ 38,595	$ 0.49	$ 21,182	$ 0.35
Litigation resolution	9,633	0.10	-	-	-	-
Equity compensation	12,639	0.13	8,465	0.11	4,454	0.07
Total general and administrative expense	$ 72,254	$ 0.75	$ 47,060	$ 0.60	$ 25,636	$ 0.42

We recognized a charge of $9.6 million in 2008 as a result of the settlement of litigation as discussed in Note 17 to our consolidated financial statements in Item 8 of this annual report. The most significant increase in recurring general and administrative expense for 2008 was a $14.4 million increase in employee compensation and benefits, including increases of $4.2 million of non-cash expense for vesting of stock-based compensation and $1.3 million in performance-based compensation. The remaining $8.9 million increase in employee compensation is related to additional headcount which was necessary to bring our infrastructure to a level needed to accommodate growth in our operations and production. After consideration of the BreitBurn Transaction investment banking fees of $2.0 million recognized in 2007, fees for legal, accounting and other professional services increased general and administrative expense by approximately $2.8 million, which resulted from additional regulatory filing requirements, litigation costs, expenses associated with evaluation of complex business transactions and the full year effect of KGS being a publicly-traded partnership.

General and administrative expense for 2007 increased due to a $4.1 million increase in stock-based compensation and $1.9 million in performance-based compensation. These increases relate to increased headcount at our corporate offices to develop additional capabilities necessary to support our growth. General and administrative costs increased year over year by $4.1 million for legal and professional fees which relate to professional services provided for the KGS IPO and our Northeast Operations divestiture.

Other Components of Operating Income

During 2007, we recognized a gain of $628.7 million as a result of our divestiture of the Northeast Operations, and we recorded a loss on the Michigan Sales Contract related to delivery of volumes in Michigan. Further information regarding these transactions is included in Item 8 of this annual report, which is incorporated herein by reference.

BreitBurn-Related Income and Expenses

During 2008, we recognized $93.3 million associated with the equity earnings in our investment in BBEP for the period from November 1, 2007, when we acquired the BBEP units, through September 30, 2008. This amount reflects our prevailing ownership interests for the applicable period before and after our ownership increased from 32% to 41% by virtue of BBEP's purchase and retirement of units during 2008. BBEP has experienced significant volatility in their net earnings due to changes in value of their derivative instruments, for which they do not employ hedge accounting.

During the fourth quarter of 2008, the Company considered the fair value of the BBEP units along with the fair value trend of its peers, the trend and future petroleum strip prices and the limited availability of credit which occurred in the latter half of 2008. Based on these factors, the Company determined that the decrease in fair value of BBEP units was other-than-temporary and recorded a pretax charge of $320.4 million to reduce the carrying value of our investment in BBEP to its fair value. Management believes that certain alternative fair value measures, such as BBEP's liquidation value, the estimated value of its properties and reserves, the present value of existing distribution levels and other calculations would have eliminated or materially lowered the impairment charge. However, the prescriptive nature of the relevant GAAP requires the Company to ignore these alternative measures based upon availability of Level 1 inputs as described in SFAS No. 157.

Interest Expense

	Years Ended December 31,		
	2008	2007	2006
		(in thousands)	
Interest costs	$ 111,735	$ 71,618	$ 45,943
Less: Interest capitalized	(9,225)	(1,091)	(1,882)
Interest expense	$ 102,510	$ 70,527	$ 44,061

Interest costs for 2008 were higher than 2007 primarily because of higher average debt outstanding due to the issuance of our Senior Notes and our Senior Secured Second Lien Facility due in 2013, partially offset by a decrease in our average consolidated interest rate. The higher debt levels in 2008 relate to the Alliance Acquisition and the funding of our 2008 capital program. The increase in capitalized interest relates to more projects and costs within those projects being subject to capitalization. Interest was capitalized in 2008 for our exploration projects in the Horn River Basin and West Texas and construction of the Corvette Plant by KGS.

For 2007, interest expense increased $26.5 million from 2006 primarily as a result of both higher debt balances and higher prevailing rates on the variable portion of our debt. The increases in 2007 debt balances primarily relate to the drilling and midstream expansion programs undertaken in 2007, but were partially offset by our debt reductions in November, funded by proceeds from our Northeast Operations' divestiture.

Income Taxes

	Years Ended December 31,		
	2008	2007	2006
		(in thousands)	
Income tax expense (benefit)	$(209,149)	$256,508	$38,150
Effective tax rate	35.9%	34.9%	28.9%

The 2008 provision for income taxes changed dramatically from 2007 due to the loss generated by U.S. operations for 2008. Pretax results for 2008 compared with 2007 were most significantly influenced by the impairment charges recognized on U.S. oil and gas properties and on our investment in BBEP. Also, 2007 results included the gain resulting from our divestiture of our Northeast Operations. Higher Canadian pretax income and the absence of tax credits received in 2007 increased the provision for income taxes in Canada by $11.1 million. In 2008, the effective rate exceeds the statutory rate of 35% due to the benefit of lower taxes in Canada partially offset by impact of permanent differences for executive compensation and meals and entertainment.

Income tax expense for 2007 was $256.5 million which yielded the effective rate of 34.9%. The 600 basis point increase in the effective rate is principally due to taxes on the gain associated with the divestiture of our Northeast Operations at the U.S. statutory rate, which is higher than the comparable Canadian rate. Thus our taxable income was more heavily weighted toward the U.S.in 2007 compared with 2006. Also, the recognition in 2007 of tax expenses pursuant to FIN 48 and a decrease in the tax credits generated by our Canadian operations increased the effective rate, offset in part by a reduction for the effect of a future tax rate reduction in Canada. Our U.S. income tax expense of approximately 35.5% was established using the statutory U.S. federal rate of 35% plus the effects of the Texas margin tax that was enacted in May 2006. Our Canadian tax expense was established using the combined federal and provincial rate of 29% and the effects of tax rate reductions that were enacted in 2007.

LIQUIDITY, CAPITAL RESOURCES AND FINANCIAL POSITION

Cash Flow Activity

Operating Cash Flows

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Net cash provided by operating activities	$ 456,566	$ 319,104	$ 242,186

Cash flows provided by operating activities in 2008 were $456.6 million, an increase of $137.5 million or 43% from 2007. The increase in operating cash flows results from a 23% production increase and a 16% increase in realized price per Mcfe. Payments of $46.6 million for income taxes and other uses of working capital partially offset the increase in cash earnings.

Cash flows provided by operating activities in 2007 were $319.1 million, an increase of $76.9 million or 32% from 2006. The cash flows increased due to a 27% production increase, an 11% realized price increase and higher cash flows provided by working capital.

Investing Cash Flows

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Purchases of property, plant and equipment	$ (1,286,715)	$(1,020,684)	$ (619,061)
Alliance Acquisition	(993,212)	-	-
Return of investment from equity affiliates	-	9,635	1,923
Proceeds from sales of properties & equipment	1,339	741,297	5,113
Net cash used by investing activities	$ (2,278,588)	$ (269,752)	$ (612,025)

For each of the three years ended December 31, 2008, we have spent significant cash resources for the development of our large acreage positions in our core areas in the Fort Worth Basin and the CBM properties in Alberta. In addition, our expenditures for gas processing and gathering assets have grown significantly as part of our growth in the Barnett Shale. In 2008 and 2007, our investing cash flows included the $1.0 billion cash portion of the Alliance Acquisition and net cash proceeds of $741.1 million from the divestiture of our Northeast Operations, respectively. Of the $2.3 billion of cash paid for property, plant and equipment during 2008, 88% was invested in our oil and natural gas properties and 12% was invested in our gas processing and gathering operations.

Our 2008 purchases of property, plant and equipment reflect our expansion in our two core operating areas, the Fort Worth Basin and the Western Canadian Sedimentary Basin in Alberta. In 2008, we purchased approximately 90 producing wells in the Alliance Acquisition and drilled 296 (259.7 net) wells in the Fort Worth Basin and 373 (156.9 net) wells in Canada. Additionally, the assets purchased in the Alliance Acquisition included a gathering system and we invested $230.4 million and $4.3 million for Fort Worth Basin and Canadian gas processing and gathering facilities, respectively.

Capital costs incurred for development, exploitation and exploration activities in 2007 were $852.5 million, primarily for expansion in our two core operating areas. In 2007, we drilled 244 (219.4 net) wells in the Fort Worth Basin and an additional 356 (184.1 net) wells in Canada. Additionally, we invested $168.5 million and $3.4 million for Fort Worth Basin and Canadian gas processing and gathering facilities, respectively.

Capital costs incurred for development, exploitation and exploration activities in 2006 were $544.7 million. Those expenditures also reflect our two core operating areas. In 2006, we drilled 123 (111.3 net) wells in the Fort Worth Basin and an additional 400 (215.2 net) wells in Canada. Additionally, we invested $82.3 million and $7.6 million for Fort Worth Basin and Canadian gas processing and gathering facilities, respectively.

We currently estimate that our spending for property, plant and equipment in 2009 will be approximately $600 million, of which we have allocated $400 million for drilling activities, $155 million for gathering and processing facilities (including $35 million to be funded directly by KGS), $40 million for acquisition of additional leasehold interest and $5 million for other property and equipment.

Financing Cash Flows

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Cash flow provided by financing activities:			
Issuance of debt	$ 2,948,672	$ 817,821	$ 694,682
Repayments of debt	(1,096,163)	(968,557)	(350,754)
Debt issuance costs	(25,219)	(5,130)	(9,213)
Minority interest contributions	-	109,809	7,291
Minority interest distributions	(8,644)	(8,794)	-
Proceeds from exercise of stock options	1,244	21,387	19,689
Excess tax benefit on exercise of stock options	-	2,755	-
Purchase of treasury stock	(23,137)	(1,567)	(384)
Net cash provided (used) by financing activities	$ 1,796,753	$ (32,276)	$ 361,311

Net cash flows from financing activities during 2008 were significantly impacted by the Alliance Acquisition and our 2008 capital program. We funded our capital program in excess of operating cash flow through the issuance of our Senior Notes and additional borrowing under our Senior Secured Credit Facility. The Alliance Acquisition was funded by a $700 million five-year Senior Secured Second Lien Facility and additional borrowing under our Senior Secured Credit Facility.

Net cash flows from financing activities during 2007 were significantly impacted by the KGS IPO and the divestiture of our Northeast Operations. The KGS IPO resulted in cash proceeds of $110 million primarily used to repay debt. The divestiture of our Northeast Operations generated net cash proceeds of $741.1 million included in investing activities, however those proceeds were used to pay down debt previously outstanding which affected financing cash flows.

Liquidity and Borrowing Capacity

On February 9, 2007, we extended our Senior Secured Credit Facility to February 9, 2012. The facility provides for revolving loans, swingline loans and letters of credit from time to time in an aggregate amount not to exceed the borrowing base which is calculated based on several factors. As of December 31, 2008, the borrowing base was equal to $1.2 billion, and is subject to annual redeterminations and certain other redeterminations. The lenders agreed to provide $1.2 billion of revolving credit commitments and the Company has an option to increase the facility to $1.45 billion. The lenders' commitments under the facility are allocated between U.S. and Canadian funds, with U.S. currency available for borrowing by the Company and either U.S. or Canadian currency available for borrowing in Canada. The facility offers the option to extend the maturity up to two additional years with lender approval. U.S. borrowings under the facility are secured by, among other things, Quicksilver's and its domestic subsidiaries' oil and gas properties including applicable reserves. Canadian borrowings under the facility are secured by, among other things, all of our oil and gas properties including applicable reserves. The Company also pledged the equity interests in BBEP it received as part of the BreitBurn Transaction to secure its obligations under the Senior Secured Credit Facility.

The credit facility contain covenants that are more fully described in Note 14 to the consolidated financial statements in Item 8 of this annual report. At December 31, 2008, approximately $369 million was available for borrowing under our Senior Secured Credit Facility and we were in compliance with all covenants. As of January 31, 2009, we had borrowed an additional $130 million under the credit facility. Our ability to remain in compliance with the financial covenants in our credit facility 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.

In connection with the KGS IPO, KGS entered into a five-year $150 million senior secured revolving credit facility ("KGS Credit Agreement"). In October 2008, the lenders increased the facility to $235 million. Additionally, the revised KGS Credit Agreement features an accordion option of $115 million that allows for the facility to increase to $350 million upon lender approval. KGS must maintain certain financial ratios that can limit its borrowing capacity. The KGS Credit Agreement contains covenants that are more fully described in Note 14 to the consolidated financial statements in Item 8 of this annual report. At December 31, 2008, KGS' borrowing capacity was $235 million, and KGS had $175 million in borrowings outstanding under the KGS Credit Agreement. KGS was in compliance with all covenants as of December 31, 2008. KGS's ability to remain in compliance with the financial covenants in its credit facility may be affected by events beyond our control. Any future inability to comply with these covenants, unless waived by the requisite lenders, could adversely affect our liquidity by rendering KGS unable to borrow further under its credit facility and by accelerating the maturity of its indebtedness.

As of December 31, 2008, 2007 and 2006, our total capitalization was as follows:

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Long-term and short-term debt:			
Senior secured credit facility	$ 827,868	$ 310,710	$ 421,123
Senior secured second lien facility	641,555	-	-
Senior notes	469,062	-	-
Senior subordinated notes	350,000	350,000	350,000
Convertible subordinated debentures	148,219	148,107	147,994
KGS credit agreement	174,900	5,000	-
Various loans	-	34	400
Total debt	2,611,604	813,851	919,517
Stockholders' equity	1,094,709	1,068,355	575,666
Total capitalization	$ 3,706,313	$ 1,882,206	$ 1,495,183

We believe that our capital resources are adequate to meet the requirements of our existing business. We anticipate that our 2009 capital expenditure budget of approximately $600 million will be funded by cash flow from operations, including application of anticipated income tax refunds and cash distributions received from BBEP. We may, from time to time during 2009, make borrowings under the credit facility, but expect that for all of 2009 to require no incremental borrowings from ending 2008 levels.

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, 2008, as compared to our balance sheet as of December 31, 2007:

- Our accounts receivable balance increased $53.1 million primarily as a result of accrual for the refund of U.S. federal income taxes paid in 2008 for the 2007 tax year. The refund is the result of incurring a loss for the 2008 tax year.

- Our current and deferred derivative assets increased $160.9 million and $115.7 million, respectively, as our current and deferred derivative obligations decreased $54.2 million and $16.3 million, respectively. Our current derivative obligations include the $8.1 million fair value loss for the remaining term of the Michigan Sales Contract. Additionally, our current deferred income tax asset decreased $19.0 million and our current deferred income tax liability increased $52.4 million as a result overall higher valuations of our derivative valuations.

- Investments in equity affiliates decreased primarily due to the recognition of a $320 million impairment of our investment in BBEP during 2008.

- The $1.7 billion increase in our net property, plant and equipment resulted primarily from $1.3 billion in capital expenditures for development, exploitation and exploration of our existing oil and gas properties and expansion of our gas processing and gathering assets in addition to the $1.3 billion of oil and gas properties and gathering assets purchased in the Alliance Acquisition. Offsetting these increases were the $634 million impairment of our U.S. oil and gas properties and ongoing DD&A.

- Long-term debt increased due to borrowings needed to fund the Alliance Acquisition and our 2008 capital program.

Contractual Obligations and Commercial Commitments

Contractual Obligations. Information regarding our contractual and scheduled interest obligations, at December 31, 2008, is set forth in the following table.

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
			(In thousands)		
Long-term debt	$2,632,373	$ 6,579	$1,022,505	$ 628,289	$ 975,000
Scheduled interest obligations	485,995	71,428	202,342	134,130	78,095
Transportation contracts	399,016	8,768	100,240	93,121	196,887
Purchase obligations	13,800	13,800	-	-	-
Natural gas supply contract	8,063	8,063	-	-	-
Drilling rig contracts	71,550	45,620	25,930	-	-
Asset retirement obligations	35,193	440	189	126	34,438
Financial derivative obligations	1,865	1,865	-	-	-
Unrecognized tax benefits	9,255	-	9,255	-	-
Operating lease obligations	7,484	3,612	3,863	9	-
Total obligations	$3,664,594	$ 160,175	$1,364,324	$ 855,675	$1,284,420

- *Long-Term Debt.* As of December 31, 2008, our outstanding indebtedness included $828 million outstanding under our Senior Secured Credit Facility, $655 million under our Senior Secured Second Lien Facility, $475 million of Senior Notes, $350 million of Senior Subordinated Notes, $150 million of convertible debentures and $175 million outstanding under the KGS credit facility (all before discount). Based upon our debt outstanding and interest rates in effect at December 31, 2008, we anticipate interest payments, including our scheduled interest obligations of $71.4 million, to be approximately $146.3 million in 2009. Although we do not expect year-over-year increased borrowings under our Senior Secured Credit Facility during 2009, should we be required to increase those borrowings and based on interest rates in effect at December 31, 2008, an additional $50 million in borrowings would result in additional annual interest payments of approximately $1.7 million. If the borrowing base under our Senior Secured Credit Facility were to be fully utilized by year-end 2009 at interest rates in effect at December 31, 2008, we estimate that interest payments would increase by approximately $12.8 million. If interest rates on our December 31, 2008 variable debt balance of $1.7 billion increase or decrease by one percentage point, our annual pretax income would decrease or increase by $1.7 million.

- *Scheduled Interest Obligations.* As of December 31, 2008, we had scheduled interest payments of $39.2 million annually on our $475 million of Senior Notes due July 1, 2015, $24.9 million annually on our $350 million of Senior Subordinated Notes due March 31, 2016 and $2.8 million annually on our $150 million of contingently convertible debentures due November 1, 2024.
- *Transportation Contracts.* Under contracts with various pipeline companies, we are obligated to transport minimum daily gas volumes, as calculated on a monthly basis, or pay for any volume deficiencies at a specified reservation fee rate. Our production committed to the pipelines is expected to meet, or exceed, the daily volumes provided in the contracts.
- *Purchase Obligations.* At December 31, 2008, we were under contract to purchase goods and services for completion of the Corvette Plant and for compressors. Total remaining cash obligations for such items were $13.8 million, including $1.2 million of goods and services recognized during 2008. The Corvette Plant was placed into service during the first quarter of 2009.
- *Natural Gas Supply Contract.* During 2007, we determined we would no longer deliver a portion of our natural gas production to supply the contractual volumes under the Michigan Sales Contract. We recorded a loss of $63.5 million for the fair value of the remaining contractual volumes during 2007. At December 31, 2008, we had a remaining liability of $8.1 million covering the remaining volumes under the contract that ends March 31, 2009.
- *Drilling Rig Contracts.* 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 $20,000 to $23,200 for the entire lease term regardless of our utilization of the drilling rigs.
- *Asset Retirement Obligations.* Our obligations result from the acquisition, construction or development and the normal operation of our long-lived assets.
- *Financial Derivative Obligations.* We utilize financial derivatives to manage price risk associated with our production revenue. The recorded assets and liabilities associated with our derivative obligations were estimated based on published market prices of commodities for the periods covered by the contracts. These amounts do not necessarily reflect the payments that will be made to settle these obligations.
- *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. The $9.3 million balance of unrecognized tax benefits includes $8.9 million of amounts that, if recognized, would reduce our effective tax rate.
- *Operating Lease Obligations.* We lease office buildings and other property under operating leases. Our operating lease obligations include $0.6 million of future lease payments to an affiliated entity, which is owned by members of the Darden family.

Commercial Commitments. We had the following commercial commitments as of December 31, 2008:

	Amounts of Commitments by Expiration Period				
	Total	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**More than 5 Years**
			(In thousands)		
Purchase commitments	$ 3,400	$ 3,400	$ -	$ -	$ -
Surety bonds	41,284	41,284	-	-	-
Standby letters of credit	3,047	3,047	-	-	-
Total	$ 47,731	$ 47,731	$ -	$ -	$ -

- *Purchase Commitments.* Purchase commitments have been made to ensure delivery of material and parts required for our drilling and completion programs and KGS infrastructure expansions.
- *Surety Bonds.* Our surety bonds have been issued to fulfill contractual, legal or regulatory requirements. All of our surety bonds have an annual renewal option.
- *Standby Letters of Credit.* Our letters of credit have been issued to fulfill contractual or regulatory requirements. All of these letters of credit were issued under our Senior Secured Credit Facility and have an annual renewal option.

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, expenses 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.

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 development, exploration and acquisition 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 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 estimated 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 (i) estimated future net revenue, discounted at 10% per annum, from proved reserves, based on unescalated year-end prices and costs, adjusted for contract provisions, financial derivatives that hedge the Company's oil and gas revenue and asset retirement obligations, (ii) the cost of properties not being amortized, (iii) the lower of cost or market value of unproved properties included in the cost being amortized less (iv) 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 revenue for our proved oil, natural gas and NGL reserves is a major component of the ceiling calculation, and represents the component that requires the most subjective judgments. 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.

The passage of time provides more qualitative information regarding estimates of reserves, and revisions are made to prior estimates to reflect updated information. In the past five years, annual revisions to our reserve estimates, which have been both increases and decreases in individual years, have averaged approximately 1% of the 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.

While the quantities of proved reserves require substantial judgment, the associated prices of natural gas, NGL and crude oil reserves, and the applicable discount rate, that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation requires that a 10% discount factor be used and that prices and costs in effect as of the last day of the period are held constant indefinitely. Therefore, the future net revenue associated with the estimated proved reserves is not based on our assessment of future prices or costs. Rather, they are based on such prices and costs in effect as of the end of each period when the ceiling calculation is performed. In calculating the ceiling, we adjust the period-end price by the effect of derivative contracts in place that hedge future prices. This adjustment requires little judgment as the period-end price is adjusted using the contract prices for such hedges.

Because the ceiling calculation dictates that prices in effect as of the last day of the applicable year are 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 period end, prices can be either substantially higher or lower than our long-term price forecast. 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.

Oil and Gas Reserves

Policy Description

Proved oil and gas reserves are the estimated quantities of crude 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. Prices include consideration of changes in existing prices provided only by contractual arrangements, which do not include financial derivatives that hedge our oil and gas revenue. Our estimates of proved reserves are made 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.

Judgments and Assumptions

All of the reserve data in this annual report are based on estimates. Estimates of our crude oil, natural gas and NGL reserves are prepared in accordance with guidelines established by the SEC. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil, natural gas and NGLs. There are numerous uncertainties inherent in estimating quantities of proved crude 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 crude oil, natural gas and NGLs that are ultimately recovered. Estimates of proved crude oil, natural gas and NGL reserves significantly affect our depletion expense. For example, if estimates of proved reserves decline, the depletion rate will increase, resulting in a decrease in net income.

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. For derivative instruments that qualify as cash flow hedges, the effective portions of gains or losses are deferred in 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 would be immediately recorded to earnings. The ineffective portion of the hedge relationship is recognized currently as a component of other revenue.

The fair value of our natural gas derivatives and associated firm sales commitments as of December 31, 2008 was estimated based on published market prices of natural gas for the periods covered by the contracts. Estimates were determined by applying the net differential between the prices in each derivative and commitment and market prices for future periods, to the volumes stipulated in each contract to arrive at an estimated value of future cash flow streams. These estimated future cash flow values were then discounted for each contract at rates commensurate with federal treasury instruments with similar contractual lives to arrive at estimated fair value.

Judgments and Assumptions

The estimates of the fair values of our commodity derivative instruments require substantial judgment. Valuations are based upon multiple factors such as futures prices, volatility data from major oil and gas trading points, 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.

Stock-based Compensation

Policy Description

SFAS No. 123 (revised 2004), *Share-Based Payment* (SFAS 123R) requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors based on estimated fair value.

Judgments and Assumptions

Option-pricing models and generally accepted valuation techniques require management to make assumptions and to apply judgment to determine the 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 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 the Company. 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

We have no off-balance sheet arrangements within the meaning of Item 303(a)(4) of SEC Regulation S-K.

RECENTLY ISSUED ACCOUNTING STANDARDS

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

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

The information required by this Item is incorporated herein by reference to the information in Note 7 to our consolidated financial statements in Item 8 of this annual report, which is incorporated herein by reference.

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, 2008 and 2007, and the related consolidated statements of income (loss) and comprehensive income (loss), stockholders' equity and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Quicksilver Resources Inc. and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

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, 2008, 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 March 2, 2009 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Fort Worth, Texas
March 2, 2009

QUICKSILVER RESOURCES INC.
CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006
In thousands, except for per share data

	2008	2007	2006
Revenues			
Natural gas, NGL and crude oil	$ 780,788	$ 545,089	$386,540
Other	19,853	16,169	3,822
Total revenues	800,641	561,258	390,362
Operating expenses			
Oil and gas production expense	135,661	136,831	95,176
Production and ad valorem taxes	16,794	16,142	15,619
Other operating costs	3,918	2,792	1,461
Depletion, depreciation and accretion	188,196	120,697	78,800
General and administrative	72,254	47,060	25,636
Total expenses	416,823	323,522	216,692
Impairment related to oil and gas properties	(633,515)	-	-
Income from equity affiliates	-	661	526
Gain on sale of oil and gas properties	-	628,709	-
Loss on natural gas sales contract	-	(63,525)	-
Operating income (loss)	(249,697)	803,581	174,196
Income from earnings of BBEP	93,298	-	-
Impairment of investment in BBEP	(320,387)	-	-
Other income - net	807	3,887	1,825
Interest expense	(102,510)	(70,527)	(44,061)
Income (loss) before income taxes and minority interest	(578,489)	736,941	131,960
Income tax (expense) benefit	209,149	(256,508)	(38,150)
Minority interest expense, net of income tax	(4,654)	(1,055)	(91)
Net income (loss)	$(373,994)	$ 479,378	$ 93,719
Other comprehensive income (loss)			
Reclassification adjustments related to settlements of derivative contracts - net of income tax	11,969	(34,648)	(9,707)
Net change in derivative fair value - net of income tax	182,472	(14,794)	83,410
Foreign currency translation adjustment	(49,403)	29,409	(1,222)
Comprehensive income (loss)	$(228,956)	$ 459,345	$166,200
Earnings (loss) per common share - basic	($2.31)	$ 3.08	$ 0.61
Earnings (loss) per common share - diluted	($2.31)	$ 2.86	$ 0.58
Basic weighted average shares outstanding	161,622	155,475	153,413
Diluted weighted average shares outstanding	161,622	168,029	166,266

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

QUICKSILVER RESOURCES INC.
CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2008 AND 2007
In thousands, except for share data

	2008	2007
ASSETS		
Current assets		
Cash and cash equivalents	$ 2,848	$ 28,226
Accounts receivable - net of allowance for doubtful accounts	143,315	90,244
Derivative assets at fair value	171,740	10,797
Current deferred income tax asset	-	18,946
Other current assets	75,433	42,188
Total current assets	393,336	190,401
Investments in equity affiliates	150,503	420,171
Property, plant and equipment - net		
Oil and gas properties, full cost method (including unevaluated costs of $543,533 and $215,228, respectively)	3,142,608	1,764,400
Other property and equipment	655,107	377,946
Property, plant and equipment - net	3,797,715	2,142,346
Derivative assets at fair value	116,006	354
Other assets	43,011	22,574
	$4,500,571	$2,775,846
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of long-term debt	$ 6,579	$ 34
Accounts payable	282,636	192,855
Income taxes payable	40	46,601
Accrued liabilities	66,923	54,981
Derivative liabilities at fair value	9,928	64,104
Current deferred tax liability	52,393	-
Total current liabilities	418,499	358,575
Long-term debt	2,605,025	813,817
Asset retirement obligations	34,753	23,864
Derivative liabilities at fair value	-	16,327
Other liabilities	12,962	10,609
Deferred income taxes	225,440	374,645
Commitments and contingencies (Note 17)		
Deferred gain on sale of partnership interests	79,316	79,316
Minority interests in consolidated subsidiaries	29,867	30,338
Stockholders' equity		
Preferred stock, par value $0.01, 10,000,000 shares authorized, none outstanding	-	-
Common stock, $0.01 par value, 400,000,000 and 200,000,000 shares authorized, respectively; 171,742,699 and 160,633,270 shares issued, respectively	1,717	1,606
Paid in capital in excess of par value	550,851	272,515
Treasury stock of 4,572,795 and 2,616,726 shares, respectively	(35,441)	(12,304)
Accumulated other comprehensive income	185,104	40,066
Retained earnings	392,478	766,472
Total stockholders' equity	1,094,709	1,068,355
	$4,500,571	$2,775,846

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

QUICKSILVER RESOURCES INC.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 AND 2006
In thousands, except for share data

	2008	2007	2006
Preferred stock, $0.01 par value, 10,000,000 shares authorized, none issued	$ -	$ -	$ -
Common stock, $0.01 par value, 400,000,000 and 200,000,000 shares authorized			
Balance at beginning of year	1,606	1,578	1,547
Issuance of common stock – Alliance Acquisition	104	-	-
Issuance of common stock – restricted stock	5	6	9
Issuance of common stock – stock options	2	22	22
Balance at end of year: 171,742,699, 160,633,270 and 157,783,515 shares issued at December 31, 2008, 2007 and 2006, respectively	1,717	1,606	1,578
Paid in capital in excess of par value			
Balance at beginning of year	272,515	237,287	211,083
Stock issuance – Alliance Acquisition	261,988	-	-
Stock options exercised	1,242	21,365	19,667
Stock-based compensation expense recognized	15,106	11,108	6,537
Tax benefit related to stock options exercised	-	2,755	-
Balance at end of year	550,851	272,515	237,287
Treasury stock, at cost			
Balance at beginning of year	(12,304)	(10,737)	(10,353)
Acquisition of treasury stock	(23,137)	(1,567)	(384)
Balance at end of year: 4,572,795, 2,616,726 and 2,579,671 shares at December 31, 2008, 2007, and 2006, respectively	(35,441)	(12,304)	(10,737)
Accumulated other comprehensive income			
Deferred gains (losses) on hedge derivatives			
Balance at beginning of year	(4,248)	45,194	(28,509)
Reclassification adjustments related to settlements of derivative contracts	11,969	(34,648)	(9,707)
Net change in derivative fair value	182,472	(14,794)	83,410
Balance at end of year	190,193	(4,248)	45,194
Deferred foreign exchange adjustment			
Balance at beginning of year	44,314	14,905	16,127
Foreign currency translation adjustment	(49,403)	29,409	(1,222)
Balance at end of year	(5,089)	44,314	14,905
Total accumulated other comprehensive income	185,104	40,066	60,099
Retained earnings			
Balance at beginning of year	766,472	287,439	193,720
Adoption of FIN 48	-	(345)	-
Net income (loss)	(373,994)	479,378	93,719
Balance at end of year	392,478	766,472	287,439
Total stockholders' equity	$1,094,709	$1,068,355	$575,666

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

QUICKSILVER RESOURCES INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS END DECEMBER 31, 2008, 2007 AND 2006
In thousands

	2008	2007	2006
Operating activities:			
Net income (loss)	$ (373,994)	$ 479,378	$ 93,719
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and accretion	188,196	120,697	78,800
Impairment related to oil and gas properties	633,515	-	-
Deferred income tax expense (benefit)	(164,134)	209,943	37,877
(Gain) loss from sale of properties	605	(627,348)	188
Non-cash (gain) loss from hedging and derivative activities	(1,139)	62,515	-
Stock-based compensation	16,128	11,243	6,546
Amortization of deferred charges	2,527	2,189	226
Amortization of deferred loan costs	4,100	2,050	2,070
Minority interest expense	4,654	1,055	91
Income from equity affiliates in excess of cash distributions	(50,762)	-	-
Impairment of investment in BBEP	320,387	-	-
Provision for doubtful accounts	-	(349)	701
Divestiture expenses	-	2,015	-
Changes in assets and liabilities			
Accounts receivable	(53,071)	(14,423)	(1,100)
Prepaid expenses and other assets	(5,448)	(4,805)	(5,021)
Accounts payable	7,602	18,939	15,193
Income taxes payable	(46,561)	46,012	308
Accrued and other liabilities	(26,039)	9,993	12,588
Net cash provided by operating activities	456,566	319,104	242,186
Investing activities:			
Purchases of property, plant and equipment	(1,286,715)	(1,020,684)	(619,061)
Alliance Acquisition	(993,212)	-	-
Return of investment from equity affiliates	-	9,635	1,923
Proceeds from sales of properties and equipment	1,339	741,297	5,113
Net cash used in investing activities	(2,278,588)	(269,752)	(612,025)
Financing activities:			
Issuance of debt	2,948,672	817,821	694,682
Repayments of debt	(1,096,163)	(968,557)	(350,754)
Debt issuance costs	(25,219)	(5,130)	(9,213)
Minority interest contributions	-	109,809	7,291
Minority interest distributions	(8,644)	(8,794)	-
Proceeds from exercise of stock options	1,244	21,387	19,689
Excess tax benefits on exercise of stock options	-	2,755	-
Purchase of treasury stock	(23,137)	(1,567)	(384)
Net cash provided by (used in) financing activities	1,796,753	(32,276)	361,311
Effect of exchange rate changes in cash	(109)	5,869	(509)
Net increase (decrease) in cash	(25,378)	22,945	(9,037)
Cash and cash equivalents at beginning of period	28,226	5,281	14,318
Cash and cash equivalents at end of period	$ 2,848	$ 28,226	$ 5,281

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

1. NATURE OF OPERATIONS

Quicksilver Resources Inc. ("Quicksilver" or the "Company") is an independent oil and gas company incorporated in the state of Delaware and headquartered in Fort Worth, Texas. Quicksilver engages in the development, exploitation, exploration, acquisition, production and sale of natural gas, NGLs and crude oil as well as the marketing, processing and transmission of natural gas. As of December 31, 2008, substantial portions of Quicksilver's oil and gas reserves and operations are located in Texas, the U.S. Rocky Mountains and Alberta, Canada. The Company has offices located in Fort Worth, Texas, Cut Bank, Montana, Glen Rose, Texas and in Calgary, Alberta. Until the Company completed the BreitBurn Transaction in 2007 (see Note 5), the Company also had significant oil and gas reserves and operations in Michigan, Indiana and Kentucky.

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

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The Company's consolidated financial statements include the accounts of Quicksilver and all its majority-owned subsidiaries and companies over which the Company exercises control through majority voting rights. We eliminate all inter-company balances and transactions in preparing consolidated financial statements. The Company accounts for its ownership in unincorporated partnerships and companies, including BBEP, under the equity method as it has significant influence over those entities, but because of terms of the ownership agreements, Quicksilver does not meet the criteria for control which would trigger consolidation of the entities. The Company also consolidates its share of oil and gas joint ventures.

Stock Split

On January 7, 2008, Quicksilver announced that its Board of Directors declared a two-for-one stock split of Quicksilver's outstanding common stock effected in the form of a stock dividend. The stock dividend was payable on January 31, 2008, to holders of record at the close of business on January 18, 2008. The split had no effect on shares held in treasury. The capital accounts, all share data and earnings per share data included in these consolidated financial statements for all years presented have been adjusted to retroactively reflect the January 2008 stock split.

Use of Estimates

The preparation of financial statements in conformity with GAAP in the U.S. requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses, including stock compensation 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 the Company's estimates. Significant estimates underlying these financial statements include the estimated quantities of proved natural gas, NGL and crude oil reserves used to compute depletion expense and future net cash flows from reserve production, estimates of current revenue based upon expectations for actual deliveries and prices received, the estimated fair value of financial derivative instruments and the estimated fair value of asset retirement obligations.

Cash and 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

The Company's customers are natural gas, NGL and crude oil purchasers. Each customer and/or counterparty of the Company is reviewed as to credit worthiness prior to the extension of credit and on a regular basis thereafter. Although the Company does not require collateral, appropriate credit ratings are required and, in some instances, parental guarantees are obtained. Receivables are generally due in 30-60 days. When collections of specific amounts due are no longer reasonably assured, an allowance for doubtful accounts is established. During 2008, two purchasers individually accounted for 17% and 10% of the Company's consolidated natural gas, NGL and crude oil revenue. During 2007 and 2006, one purchaser accounted for approximately 13% and 10%, respectively, of the Company's consolidated natural gas, NGL and crude oil revenue.

Hedging and Derivatives

The Company enters into financial derivative instruments to mitigate risk associated with the prices received from its natural gas, NGL and crude oil production. The Company may also utilize financial derivative instruments to hedge the risk associated with interest rates on its 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. For derivatives instruments that qualify as cash flow hedges, the effective portions of gains and losses are deferred in other comprehensive income and recognized in revenue or interest expense in the period in which the hedged transaction is recognized. Gains or losses on derivative instruments terminated prior to their original expiration date are deferred and recognized as earnings during the period in which the hedged transaction is recognized. If the hedged transaction becomes probable of not occurring, 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.

Until December 2007, the Michigan Sales Contract, which required delivery of 25 MMcfd of owned or controlled natural gas at a floor of $2.49 per Mcf through March 2009, had been excluded from derivatives as it was designated as a normal sales contract under accounting rules. In December 2007 and in connection with the divestiture of the Northeast Operations, the Company decided it would cease delivering a portion of its natural gas production to supply the contractual volumes. As the contract no longer qualified under the normal sales exclusion under derivative GAAP, the Company recognized a loss of $63.5 million at that time.

Until May 2007, the Company also had another long-term contract (the "CMS Contract") for delivery of 10 MMcfd of owned or controlled natural gas at a floor price of $2.47 that was treated as a normal sales contract under SFAS No. 133. See Note 17 to these financial statements for more information regarding the CMS Contract.

Parts and Supplies

Parts and supplies consist of well equipment, spare parts and supplies carried on a first-in, first-out basis at the lower of cost or market.

Investments in Equity Affiliates

Income from equity affiliates is included as a component of operating income when the operations of the affiliates are associated with processing and transportation of the Company's natural gas production.

The Company accounts for it investment in BBEP using the equity method. The Company reviews its investment for impairment whenever events or circumstances indicate that the investment's carrying amount may not be recoverable. The Company records its portion of BBEP's earnings during the quarter in which their financial statements become publicly available. Thus, the Company's 2008 results of operations reflect BBEP's earnings from November 1, 2007, when the Company acquired the BBEP units, through September 30, 2008. The Company is not aware of any significant events or transactions subsequent to September 30, 2008 that will affect BBEP's results of operations after that date. See Note 10 for more information on the BBEP investment.

Property, Plant, and Equipment

The Company follows the full cost method in accounting for its 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 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. 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 (i) estimated future net revenue, discounted at 10% per annum, from proved reserves, based on unescalated year-end prices and costs, adjusted for contract provisions, financial derivatives that hedge the Company's oil and gas revenue and asset retirement obligations, (ii) the cost of properties not being amortized, (iii) the lower of cost or market value of unproved properties included in the cost being amortized less (iv) income tax effects related to differences between the book and tax basis of the natural gas and crude 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 11 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.

Revenue Recognition

Revenue is recognized when title to the products transfer to the purchaser. The Company uses the "sales method" to account for its production revenue, whereby the Company recognizes revenue on all natural gas, NGL or crude oil sold to its purchasers, regardless of whether the sales are proportionate to the Company's ownership in the property. A receivable or liability is recognized only to the extent that the Company has an imbalance on a specific property greater than the expected remaining proved reserves. As of December 31, 2008 and 2007, the Company's aggregate production imbalances were not material.

Environmental Compliance and Remediation

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

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 be adjusted to reflect tax rates expected to be in effect in years in which the temporary differences reverse. Canadian taxes are calculated at rates 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

The Company measures and recognizes compensation expense for all share-based payment awards made to employees and directors based on their estimated fair value. At the discretion of the board of directors, the Company may issue awards payable in cash. For all awards, the Company recognizes 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

The Company's 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 at the present value of future cash flows discounted at rates consistent with comparable maturities for 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. SFAS No. 157, *Fair Value Measurements*, was adopted on January 1, 2008 and applied to fair value measurements of the Company's financial instruments, including its financial derivative instruments. Additional information regarding the Company's implementation of the accounting standard is found under "Recently Issued Accounting Standards" in this Note.

Minority Interest in Consolidated Subsidiaries

Minority interest reflects the fractional outside ownership of the Company's majority-owned and consolidated subsidiaries. Minority interest does not necessarily reflect the fair value of that outside ownership.

Foreign Currency Translation

The Company's Canadian subsidiary uses the Canadian dollar as its functional currency. All balance sheet accounts of the Canadian operations are translated into U.S. dollars at the period-end rate of exchange and statement of income items are translated at the weighted average exchange rates 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 statement of income.

Earnings per Share

Basic earnings per common share is computed by dividing the net income attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Diluted net income or loss per common share is computed using the treasury stock method, which also considers the impact to net income and common shares for the potential dilution from stock options, unvested restricted stock and convertible debt.

The following is a reconciliation of the numerator and denominator used for the computation of basic and diluted net income per common share. Total per share amounts may not add due to rounding. For the year ended December 31, 2008, all dilutive securities were excluded from the diluted net loss per share calculation as they were antidilutive. No outstanding options were excluded from the diluted net income per share calculation for the years ended December 31, 2007 and 2006.

	Years Ended December 31,		
	2008	**2007**	**2006**
	(In thousands, except per share data)		
Net income (loss)	$(373,994)	$479,378	$ 93,719
Impact of assumed conversions – interest on 1.875% convertible debentures, net of income taxes[1]	-	1,901	1,901
Income (loss) available to stockholders assuming conversion of convertible debentures	$(373,994)	$481,279	$ 95,620
Weighted average common shares – basic	161,622	155,475	153,413
Effect of dilutive securities:			
Employee stock options	-	1,326	2,220
Employee stock awards	-	1,412	817
Contingently convertible debentures	-	9,816	9,816
Weighted average common shares – diluted[1]	161,622	168,029	166,266
Earnings (loss) per common share – basic	$ (2.31)	$ 3.08	$ 0.61
Earnings (loss) per common share – diluted	$ (2.31)	$ 2.86	$ 0.58

(1) For 2008, the effects of convertible debt, stock options and unvested restricted stock were antidilutive and, therefore, excluded from the diluted share calculations

Recently Issued Accounting Standards

- **Pronouncements Implemented During 2008**

Adoption of SFAS No. 157 – SFAS No. 157, *Fair Value Measurements,* was issued by the FASB in September 2006. SFAS No. 157 defines fair value, establishes a framework for measuring fair value under GAAP and expands disclosures about fair value measurements. The Statement applies under other accounting pronouncements that require or permit fair value measurement. No new requirements are included in SFAS No. 157, but application of the Statement has changed current practice. On February 12, 2008, the FASB issued FASB Staff Position 157-2 ("FSP 157-2") which delayed the effective date of SFAS No. 157 for non-financial assets and liabilities. The delay allows companies additional time to consider the effect of various implementation issues that have arisen, or that may arise, from the application of SFAS No. 157. FSP FAS 157-3 was issued by the FASB on October 10, 2008 to clarify application of SFAS No. 157 when determining the fair value of a financial asset when the market for that financial asset is not active. The Company adopted SFAS No. 157 on January 1, 2008 for new fair value measurements of financial instruments, including its derivative instruments, and recurring fair value measurements of non-financial assets and liabilities. All financial instruments are measured using inputs from three levels of fair value hierarchy. The three levels are as follows:

> Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that we have the ability to access at the measurement date.
>
> Level 2 inputs include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).

Level 3 inputs are unobservable inputs that reflect the Company's assumptions about the assumptions that market participants would use in pricing an asset or liability.

Adoption of SFAS No. 159 – In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115.* SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. While SFAS No. 159 became effective on January 1, 2008, the Company did not elect the fair value measurement option for any of its financial assets or liabilities.

Adoption of FSP No. 39-1 – On April 30, 2007, the FASB issued FASB Staff Position ("FSP") No. 39-1, *Amendment of FASB Interpretation No. 39.* The FSP amends GAAP to replace the terms "conditional contracts" and "exchange contracts" with the term "derivative instruments" as defined in SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.* It also amends paragraph 10 of Interpretation 39 to permit a reporting entity to offset fair value amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. The Company adopted FSP No. 39-1 on January 1, 2008 without significant impact.

Adoption of SFAS No. 162 – In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*, which identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements in conformity with GAAP in the United States. This Statement is generally viewed as a necessary step in the ultimate convergence of global accounting rules. This Statement became effective on November 15, 2008, but had no impact on the Company's financial statements or related disclosures.

- **Pronouncements Not Yet Implemented**

SFAS No. 141 (revised 2007), *Business Combinations*, "SFAS No. 141(R)" was issued in December 2007. SFAS No. 141(R) replaces SFAS No. 141, *Business Combinations*, while retaining its fundamental requirements that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination. SFAS No. 141(R) defines the acquirer as the entity that obtains control in the business combination and it establishes the criteria to determine the acquisition date. SFAS No. 141(R) applies to all transactions and events in which one entity obtains control over one or more other businesses. The Statement also requires an acquirer to recognize the assets acquired and liabilities assumed measured at their fair values as of the acquisition date. In addition, acquisition costs are required to be recognized as period expenses as incurred. The Statement will apply to any acquisition entered into after January 1, 2009, but otherwise had no effect on our financial statements upon adoption.

SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51* was issued in December 2007. The Statement amends prior standards to establish new accounting and reporting standards for the noncontrolling interest in a subsidiary (previously referred to as "minority interest") and for the deconsolidation of a subsidiary. SFAS No. 160 clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as a component of its equity. The Statement also changes the way the consolidated income statement is presented by requiring consolidated net income to be reported at amounts that include the amounts attributable to both the parent and noncontrolling interest. Additionally, SFAS No. 160 establishes a single method for accounting for changes in a parent's ownership interest in a subsidiary that do not result in deconsolidation. The Company adopted this Statement on January 1, 2009 which resulted in the reclassification of the minority interest liability of $29.9 million to stockholders' equity. Also, the Company's adoption resulted in the reclassification of the $79.3 million deferred gain related to the KGS IPO to "paid in capital in excess of par value" within stockholders' equity. These two reclassifications resulted in an increase to stockholder's equity and would have resulted in the Company's net debt to capital ratio being reduced from 69% as reported on December 31, 2008 to 67% at January 1, 2009.

The FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities,* in March 2008. Under SFAS No. 161, the Company will be required to disclose the fair value of all derivative and hedging instruments and their gains or losses in tabular format and information about credit risk-related features in derivative agreements, counterparty credit risk, and its strategies and objectives for using derivative instruments. SFAS No. 161 was adopted with prospective application by the Company on January 1, 2009. The adoption of SFAS No. 161 will change the Company's disclosures about its derivative and hedging instruments, but had no impact on the Company's previously reported results or financial position.

In May 2008, the FASB issued FSP APB 14-1, "*Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)*" ("FSP APB 14-1"), which clarifies that convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement) are not addressed by paragraph 12 of APB Opinion No. 14, "Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants." In addition, FSP APB 14-1 indicates that issuers of such instruments generally should separately account for the liability and equity components in a manner that will reflect the entity's nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. FSP APB 14-1 is effective for the Company beginning January 1, 2009 with early adoption prohibited. Adoption of FSP APB 14-1 by the Company on January 1, 2009 resulted in recognition of $26.8 million of additional paid in capital in excess of par value, additional deferred tax liability of $5.8 million and decreases to other assets, long-term debt and retained earnings of $2.4 million, $19.0 million and $16.0 million, respectively. Beginning in the first quarter of 2009, the Company will be required to retroactively present prior period information in accordance with this position.

The SEC adopted revisions to its required oil and gas reporting disclosures in December 2008. The revisions impacting the Company include: 1) use of 12-month average of the first-day-of-the-month prices for determination of proved reserve values including in calculating full cost ceiling limitations; 2) limitations on the types of technologies that may be relied upon to establish the levels of certainty required to classify reserves; and 3) ability to disclose "probable" and "possible" reserves as defined by the SEC. The SEC also updated the required disclosure requirements and eliminated use of price recoveries subsequent to period end for use in the ceiling test. The Company will adopt these changes within the 2009 Annual Report on Form 10-K to be filed in 2010. The Company is still reviewing the implications of these revisions.

3. ALLIANCE ACQUISITION

In August 2008, Quicksilver completed the Alliance Acquisition, under which the Company acquired leasehold, royalty and midstream assets in the Barnett Shale in northern Tarrant and southern Denton Counties of Texas. The purchase price which was funded, in part, using $318 million of borrowings under its existing Senior Secured Credit Facility and proceeds of $674.5 million from the Senior Secured Second Lien Facility more fully described in Note 14:

(In thousands)	
Purchase Price:	
Cash paid	$1,000,000
Cash received from post-closing settlement	(8,109)
Cash paid for acquisition-related expenses	1,321
Total cash	993,212
Issuance of 10,400,468 common shares	262,092
	$1,255,304

Quicksilver's preliminary purchase price allocation is presented below:

(In thousands)	
Allocation of Purchase Price:	
Oil and gas properties – proved	$ 787,918
Oil and gas properties – unproved	441,303
Midstream assets	27,350
Liabilities assumed	(496)
Asset retirement obligations	(771)
	$1,255,304

The preliminary purchase price allocation is based on preliminary estimates of oil and gas reserves and other valuations and estimates by management and is subject to final closing adjustments and determination of the valuation of tangible assets related to wells, pipelines and facilities. The Company expects to finalize the purchase price allocation during the quarter ending September 30, 2009.

Pro Forma Information

The following table reflects the Company's unaudited consolidated pro forma statements of income as though the Alliance Acquisition, associated borrowings and issuance of Company common stock had occurred on January 1 for each year presented. The revenue and expenses for the acquisition are included in the Company's 2008 consolidated results beginning from the date of closing. The pro forma information is not necessarily indicative of the results of operations that would have been achieved had the acquisition been effective at January 1 each year presented.

	For the Years Ended December 31,	
	2008	**2007**
	(In thousands, except per share data)	
Revenues	$ 875,607	$629,868
Net income (loss)	$(377,460)	$432,302
Earnings (loss) per common share - basic	($2.19)	$2.61
Earnings (loss) per common share - diluted	($2.19)	$2.43

4. QUICKSILVER GAS SERVICES LP

On August 10, 2007, the Company's majority-owned subsidiary, KGS, completed its underwritten IPO. KGS, a limited partnership engaged in the business of gathering and processing natural gas produced from the Barnett Shale formation, sold 5,000,000 common units for $95.0 million, net of underwriters' discount and other offering costs. On September 7, 2007, the underwriters of the KGS IPO exercised their option to purchase an additional 750,000 common units for approximately $14.6 million, net of underwriters' discount.

Upon completion of the IPO, KGS paid Quicksilver approximately $112.1 million in cash and issued Quicksilver a subordinated note with a principal amount of $50 million as a return of investment capital contributed and reimbursement for capital expenditures advanced which eliminated the Company's investment in the KGS-predecessor. Due to a portion of the Company's common interests in KGS being subordinated, Quicksilver deferred recognition of a gain of approximately $79.3 million related to its post-IPO ownership in KGS. The gain was originally expected to be recognized in earnings when the subordination period terminates, however, the adoption of SFAS 160, as more fully described in Note 2, will cause this amount to be reclassified to stockholders' equity on January 1, 2009.

As of December 31, 2008, KGS' ownership is summarized in the following table:

	KGS Ownership		
	Quicksilver	Third Parties	Total
General partner interests	1.9%	-	1.9%
Limited partner interests:			
Common interests	23.5%	27.1%	50.6%
Subordinated interests	47.5%	-	47.5%
Total interests	72.9%	27.1%	100.0%

The subordinated units will convert into an equal number of common units upon termination of the subordination period. The subordination period is expected to end in February 2011, assuming KGS has earned and paid at least $0.30 per quarter on each outstanding common unit through that time.

The Company includes the results of operations and financial position of KGS in the consolidated financial statements of Quicksilver, and recognizes the portion of KGS' results of operations attributable to unaffiliated unitholders as a component of minority interest expense.

5. DIVESTITURE OF NORTHEAST OPERATIONS

In November 2007, Quicksilver closed on an agreement (the "BreitBurn Transaction") to contribute all of its oil and gas properties and facilities in Michigan, Indiana and Kentucky (collectively the "Northeast Operations") to BBEP. Total consideration for the BreitBurn Transaction was $750 million of cash and 21.348 million common units of BBEP, equaling total consideration of $1.47 billion based on closing market prices on that date. Upon closing, the Company used $654 million of proceeds from the BreitBurn Transaction to repay all U.S. borrowings then outstanding under its Senior Secured Credit Facility. Under the terms of the transaction, the Company must retain 50% of the acquired units until May 1, 2009, but may now freely trade the other acquired units.

Concurrent with closing the BreitBurn Transaction, the Company agreed to provide certain one-time benefits to 141 terminated employees, including settling unvested stock-based compensation in cash and providing cash severance and retention benefits payable in multiple installments over two years. The Company anticipates the total expense associated with the termination-related employees benefits to be approximately $10.2 million which was recognized approximately 60% in 2007 and 20% in 2008 plus an expected 20% in 2009. The $6.3 million recognized in oil and gas production costs in the latter half of 2007 was comprised of expenses to settle unvested stock-based compensation of $4.9 million and severance payments of $1.4 million associated with services rendered through the end of 2007 by affected employees. The $2.1 million recognized in 2008 and amounts to be recognized in 2009 are attributable to the services rendered or expected to be rendered by the affected employees over these periods and are payable only in the event of their continued employment by BBEP.

A portion of the Company's hedging program that was designated to the Northeast Operations for the period subsequent to the closing of the BreitBurn Transaction no longer qualifies for hedge accounting treatment. Accordingly, concurrent with the completion of the BreitBurn Transaction, the Company reclassified the amounts included in accumulated other comprehensive income for the affected Northeast Operations hedges and recognized the changes in fair value for such contracts. This aggregate recognition totaled approximately $0.8 million, which increased other revenue in the 2007 consolidated statements of income. In the fourth quarter of 2007, the Company re-designated the hedges for the Northeast Operations as hedges of other U.S. production and applied hedge accounting treatment for prospective changes in value.

The Company was considered to have a "continuing interest" in the assets and subsidiaries sold in the BreitBurn Transaction as the Company owned approximately 32% of BBEP's outstanding common units at the time of the BreitBurn Transaction. Thus, the Company deferred $294 million, or 32%, of the $923 million calculated book gain and recorded its investment in BBEP units, with an aggregate value of $724 million, net of the $294 million deferred gain for a net carrying value of $430 million at December 31, 2007. The

Company accounts for its investment in the BBEP common units using the equity method, utilizing a one quarter lag from BBEP's publicly available information. See Note 10 for recent developments regarding the Company's investment in BBEP.

In completing the BreitBurn Transaction, the Company utilized investment banking services. Approximately $2 million of expense related to such services was included in general and administrative expense during the third quarter of 2007, with an additional approximately $8.2 million recognized in the fourth quarter of 2007 as a reduction of proceeds generated by the BreitBurn Transaction.

Under the full cost method of accounting, the Company's U.S. exploration and production assets are considered a single asset. The divestiture of the Northeast Operations, therefore, represents a fractional divestiture of a single asset which precludes reporting the Northeast Operations' financial position and results of operations as discontinued operations within the consolidated financial statements.

6. DERIVATIVES AND FAIR VALUE MEASUREMENTS

In accordance with the fair value hierarchy described in SFAS No. 157, the following table shows the fair value of the Company's financial assets and liabilities that are required to be measured at fair value as of December 31, 2008.

	Fair Value Measurements as of December 31, 2008				
	Level 1	Level 2	Level 3	Other[(1)]	Balance Sheet Total
			(In thousands)		
Derivative assets	$ -	$ 295,085	$ -	$ (7,339)	$ 287,746
Derivative liabilities	$ -	$ 17,267	$ -	$ (7,339)	$ 9,928

(1) Represents amounts netted under master netting arrangements

The Company's derivative instruments at December 31, 2008 and 2007 include the Michigan Sales Contract that requires delivery of 25 MMcfd of natural gas for $2.49 per Mcf through March 2009. In December 2007 and in connection with the divestiture of the Northeast Operations, the Company decided to cease delivering a portion of its natural gas production to supply the contract. As the contract no longer qualified for the normal sales exclusion under GAAP, the Company recognized a $63.5 million loss at that time. In January 2008, the Company entered into two fixed-price natural gas swaps covering all volumes for the remaining contract period, which served to largely eliminate future earnings exposure for the Company's remaining obligation under the Michigan Sales Contract. During 2008, the Company paid $48.2 million, net of derivative settlements, to meet its obligations under the Michigan Sales Contract.

The change in carrying value of the Company's derivatives and the contractual fixed-price sale commitments in the Company's balance sheet since December 31, 2007 principally resulted from the decrease in market prices for natural gas, NGL and oil relative to the prices in our derivative instruments and, to a lesser degree, from settlements made during 2008. The change in fair value of the effective portion of all cash flow hedges was reflected in accumulated other comprehensive income, net of deferred tax effects. The Company recorded $1.6 million and $1.0 million of net gains and a $0.1 million net loss in other revenue as the result of derivative hedge ineffectiveness for the years ended December 31, 2008, 2007 and 2006, respectively.

The estimated fair values of all derivatives and fixed-price firm sale commitments of the Company as of December 31, 2008 and 2007 are provided below. The associated carrying values of these derivatives are equal to the estimated fair values for each period presented. The assets and liabilities recorded in the balance sheet are netted where derivatives with both gain and loss positions are held by a single third party where rights of offset exists.

	As of December 31,	
	2008	2007
	(In thousands)	
Derivative assets:		
Natural gas collars	$260,901	$10,491
Natural gas fixed-price swaps	34,184	4,666
	$295,085	$15,157
Derivative liabilities:		
Natural gas basis swaps	$ 4,365	$ 1,224
Natural gas fixed-price swaps[1]	4,839	-
Natural gas financial collars	-	1,625
Crude oil financial collars	-	6,517
NGL fixed-price swaps	-	11,294
Fixed-price natural gas sales contracts[1]	8,063	63,777
	$ 17,267	$84,437

[1] Includes $8.1 million and $63.5 million for the Michigan Sales Contract at December 31, 2008 and 2007, respectively, and fixed price natural gas swaps with a liability value of $4.8 million at December 31, 2008 that eliminated earnings exposure for the required natural gas purchases

Hedge derivative assets and liabilities of $176.6 million and $1.9 million, respectively have been classified as current at December 31, 2008 based on the maturity of the derivative instruments, resulting in $115.1 million of after-tax gains expected to be reclassified from accumulated other comprehensive income in 2009.

7. FINANCIAL INSTRUMENTS

Commodity Price Risk

The Company enters into financial derivative contracts to mitigate its exposure to commodity price risk associated with anticipated future natural gas production and to increase the predictability of our revenue. As of December 31, 2008, approximately 150 MMcfd and 40 MMcfd of natural gas price collars and swaps, respectively, have been put in place to hedge 2009 anticipated natural gas production. Also, approximately 160 Mmcfd of natural gas collars have been executed to hedge anticipated 2010 natural gas production.

The following tables summarize our open derivative positions as of December 31, 2008 related to the Company's natural gas production:

Product	Type	Contract Period	Volume	Weighted Avg Price Per Mcf	Fair Value
					(In thousands)
Gas	Swap	Jan 2009-Dec 2009	10,000 Mcfd	$ 8.45	$ 8,537
Gas	Swap	Jan 2009-Dec 2009	10,000 Mcfd	8.45	8,537
Gas	Swap	Jan 2009-Dec 2009	20,000 Mcfd	8.46	17,110
Gas	Collar	Jan 2009-Mar 2009	20,000 Mcfd	7.50- 9.35	3,259
Gas	Collar	Jan 2009-Mar 2009	20,000 Mcfd	8.00-10.20	4,132
Gas	Collar	Jan 2009-Dec 2009	20,000 Mcfd	7.50- 9.34	11,373
Gas	Collar	Jan 2009-Dec 2009	20,000 Mcfd	7.75-10.20	13,242
Gas	Collar	Jan 2009-Dec 2009	10,000 Mcfd	7.75-10.26	6,651
Gas	Collar	Jan 2009-Dec 2009	20,000 Mcfd	8.25- 9.60	16,083
Gas	Collar	Jan 2009-Dec 2009	10,000 Mcfd	8.25-10.45	8,290
Gas	Collar	Jan 2009-Dec 2009	10,000 Mcfd	8.25-10.45	8,290
Gas	Collar	Jan 2009-Dec 2009	10,000 Mcfd	8.25-10.45	8,290
Gas	Collar	Jan 2009-Dec 2009	10,000 Mcfd	11.50-14.48	19,520
Gas	Collar	Apr 2009-Dec 2009	10,000 Mcfd	8.50-13.15	6,796
Gas	Collar	Apr 2009-Dec 2009	30,000 Mcfd	11.00-13.50	38,970
Gas	Collar	Jan 2010-Dec 2010	20,000 Mcfd	8.00-11.00	10,423
Gas	Collar	Jan 2010-Dec 2010	20,000 Mcfd	8.00-11.00	10,423
Gas	Collar	Jan 2010-Dec 2010	20,000 Mcfd	8.00-12.20	11,077
Gas	Collar	Jan 2010-Dec 2010	20,000 Mcfd	8.00-12.20	11,077
Gas	Collar	Jan 2010-Dec 2010	10,000 Mcfd	8.50-12.05	6,778
Gas	Collar	Jan 2010-Dec 2010	20,000 Mcfd	8.50-12.05	13,555
Gas	Collar	Jan 2010-Dec 2010	10,000 Mcfd	8.50-12.08	6,795
Gas	Collar	Jan 2010-Dec 2010	40,000 Mcfd	10.00-13.50	45,877
Gas	Basis	Jan 2009-Dec 2009	20,000 Mcfd		(1,865)
Gas	Basis	Jan 2009-Dec 2009	10,000 Mcfd		(932)
Gas	Basis	Jan 2009-Dec 2009	15,000 Mcfd		(798)
Gas	Basis	Jan 2009-Dec 2009	15,000 Mcfd		(770)
				Total	$ 290,720

As discussed in Note 6, the Company also has an obligation through March 2009 to deliver 25 MMcfd of natural gas under the Michigan Sales Contract, which has a floor price of $2.49 per Mcf. In January 2008, the Company entered into two fixed-price natural gas swaps covering all remaining volumes for the remaining contract period that have served to effectively eliminate any significant net earnings exposure for the Company's remaining obligations. During 2008, the Company paid $48.2 million of net cash in settlement of its obligations under the Michigan Sales Contract.

Product	Type	Contract Period	Volume	Weighted Avg Price Per Mcf	Fair Value
					(In thousands)
Gas	Sale	Jan 2009-Mar 2009	25,000 Mcfd	$ 2.49	$ (8,063)
Gas	Swap	Jan 2009-Mar 2009	10,000 Mcfd	8.20	(1,935)
Gas	Swap	Jan 2009-Mar 2009	15,000 Mcfd	8.20	(2,904)
				Total	$ (12,902)

Utilization of our financial hedging program will most often result in the Company's realized prices from the sale of its natural gas, NGL and crude oil to vary from market prices. As a result of settlements of derivative contracts, the Company's revenue from natural gas, NGL and crude oil production was $18.4 million lower for 2008 and $51.1 million and $15.5 million higher for 2007 and 2006, respectively.

Interest Rate Risk

There were no interest rate swaps utilized during 2008 or 2007. However, interest expense for 2006 was $0.1 million lower as a result of interest rate swaps.

Credit Risk

Credit risk is the risk of loss as a result of non-performance by counterparties of their contractual obligations. The Company sells a portion of its natural gas production at spot or short-term contract prices. All its production is sold to large trading companies and energy marketing companies, refineries and other users of petroleum products. The Company also enters into hedge derivatives with financial counterparties. The Company monitors exposure to counterparties by reviewing credit ratings, financial statements and credit service reports. Exposure levels are limited and parental guarantees and collateral are used to manage our exposure to counterparties according to the Company's established policy. Each customer and counterparty is reviewed as to credit worthiness prior to the extension of credit and on a regular basis thereafter. The Company has not experienced any significant credit losses during any of the three years ended December 31, 2008.

Performance Risk

Performance risk results when a financial counterparty fails to fulfill its contractual obligations such as commodity pricing or volume commitments. Typically, such risk obligations are defined within the trading agreements. The Company manages performance risk through its management of credit risk. Each customer and counterparty is reviewed as to credit worthiness prior to the extension of credit and on a regular basis thereafter.

Foreign Currency Risk

The Company's Canadian subsidiary uses the Canadian dollar as its functional currency. To the extent that business transactions in Canada are not denominated in Canadian dollars, the Company is exposed to foreign currency exchange rate risk. For 2008, 2007 and 2006, non-functional currency transactions resulted in losses of $3.3 million, $0.8 million and $0.1 million, respectively, included in net earnings. Furthermore, the Senior Secured 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 the available borrowing capacity.

Although cross-currency transactions are minimized, the result of a 10% change in the Canadian-U.S. exchange rate would increase or decrease stockholders' equity by approximately $28 million at December 31, 2008.

8. ACCOUNTS RECEIVABLE

Accounts receivable consisted of the following:

	As of December 31, 2008	As of December 31, 2007
	(In thousands)	
Accrued production receivables	$ 47,552	$ 51,429
Income tax receivable	47,928	-
Joint interest receivables	29,420	26,026
Accrued taxes receivable	12,877	9,804
Other receivables	5,624	3,089
Allowance for doubtful accounts	(86)	(104)
	$ 143,315	$ 90,244

9. OTHER CURRENT ASSETS

Other current assets consisted of the following:

	As of December 31, 2008	As of December 31, 2007
	(In thousands)	
Spare parts and supplies	$ 64,185	$ 31,980
Prepaid production taxes	7,239	-
Prepaid drilling rentals	384	4,457
Deposits	109	2,134
Other prepaid expenses	3,516	3,617
	$ 75,433	$ 42,188

10. INVESTMENT IN BREITBURN ENERGY PARTNERS L.P.

In 2007, the Company received common units of BBEP, a publicly traded limited partnership, as part of the BreitBurn Transaction, which is more fully described in Note 5. On June 17, 2008, BBEP announced that it had repurchased and retired 14.4 million units, which represented approximately 22% of the units previously outstanding. The resulting reduction in the number of BBEP common units outstanding increased the Company's ownership from approximately 32% to approximately 41%.

During the fourth quarter of 2008, the Company evaluated its investment in BBEP for impairment in response to decreases in both prevailing commodity prices and BBEP's unit price. The Company considered numerous factors in evaluating whether this decline was other-than-temporary. In final reflection, the length of time at which BBEP traded below the Company's net carrying value per unit, prevailing petroleum prices and broad limitations on available capital resulted in the determination that the decline in value was other-than-temporary. While the Company believes that the market forces that influence commodity and equity prices are under duress, the accounting rules that govern fair value assessments are rigid in their requirement to utilize the quoted market prices for determination of fair value. Accordingly, the impairment analysis utilized the December 31, 2008 price of $7.05 per BBEP unit. This resulted in an aggregate fair value of $150.5 million for the portion of BBEP units owned by the Company, which was then compared to the carrying value of $470.9 million. The difference of $320.4 million was recognized as an impairment charge during 2008.

Summarized estimated financial information for BBEP is as follows:

	As of September 30, 2008		For the Eleven Months Ended September 30, 2008
	(In thousands)		(In thousands)
Current assets	$ 90,284	Revenues	$ 420,321
Property, plant and equipment	1,914,432	Operating expenses	251,618
Other assets	66,583	Operating income	168,703
Current liabilities	129,084	Interest and other	27,795
Long-term debt	708,000	Income tax expense	593
Other non-current liabilities	121,005	Minority interests	206
Partners' equity	1,127,679	Net income	$ 140,109
		Net income available to common unitholders	$ 141,660

Based upon the significance of the earnings impact that BBEP's operations have on the Company's consolidated statement of income, the Company is required to present BBEP's financial statements within this Annual Report on Form 10-K. However, this required information is not yet available and the Company will file an amendment to this Annual Report on Form 10-K to provide the information once it becomes publicly available.

11. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consisted of the following:

	As of December 31, 2008	As of December 31, 2007
	(In thousands)	
Oil and gas properties		
Subject to depletion	$ 3,621,831	$ 1,811,295
Unevaluated costs	543,533	215,228
Accumulated depletion	(1,022,756)	(262,123)
Net oil and gas properties	3,142,608	1,764,400
Other plant and equipment		
Pipelines and processing facilities	664,112	379,869
General properties	57,941	32,966
Accumulated depreciation	(66,946)	(34,889)
Net other property and equipment	655,107	377,946
Property, plant and equipment, net of accumulated depletion and depreciation	$ 3,797,715	$ 2,142,346

Ceiling Test Analysis

As described in Note 2, the Company is required to perform a quarterly ceiling test for each of its cost centers. The ceiling test incorporates assumptions regarding pricing and discount rates over which management has no influence in the determination of present value. Additionally, the Company's ceiling test for its U.S. cost center ignores any effects of the benefits attendant to the ownership and consolidation of KGS. In arriving at the ceiling amount for the fourth quarter of 2008, the Company used $5.71 per Mcf of natural gas, $44.60 per Bbl of oil and $21.65 per Bbl of NGL for its U.S. properties' production horizon.

When the present value of the U.S. reserves was calculated, the carrying value exceeded the ceiling limit by $624.3 million and resulted in the impairment charge recognized during the fourth quarter of 2008. The Company has the ability to examine price recoveries subsequent to December 31, 2008 for incorporation into a revised ceiling calculation; however, such changes were insufficient to eliminate the impairment charge. The Company's Canadian ceiling test required no impairment of its Canadian oil and gas properties.

During the fourth quarter of 2008, the Company determined that the exploration costs for the Delaware Basin of West Texas would become part of the U.S. full-cost pool and no longer remain excluded from depletion. The Company also evaluated its midstream assets in West Texas for impairment, recording an impairment charge of $9.2 million to reduce those midstream assets to their estimated fair values.

Unevaluated Natural Gas and Crude Oil Properties Not Subject to Depletion

Under full cost accounting, the Company 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, 2008 and 2007 and the year in which they were incurred follows:

	December 31, 2008 Costs Incurred During					December 31, 2007 Costs Incurred During				
	2008	2007	2006	Prior	Total	2007	2006	2005	Prior	Total
	(In thousands)					(In thousands)				
Acquisition costs	$ 381,203	$ 54,094	$ 31,328	$ 53,998	$ 520,623	$ 71,835	$ 25,357	$ 39,810	$ 37,834	$ 174,836
Exploration costs	19,632	-	-	-	19,632	20,334	20,058	-	-	40,392
Capitalized interest	3,278	-	-	-	3,278	-	-	-	-	-
Total	$ 404,113	$ 54,094	$ 31,328	$ 53,998	$ 543,533	$ 92,169	$ 45,415	$ 39,810	$ 37,834	$ 215,228

The following table summarizes the unevaluated property costs not subject to depletion.

	As of December 31,	
	2008	2007
	(In thousands)	
Fort Worth Basin	$440,092	$107,163
Canadian Horn River Basin	80,590	30,784
Canadian CBM	-	21,170
West Texas	-	50,908
Other	22,851	5,203
Total	$543,533	$215,228

Costs are transferred into the amortization base on an ongoing basis, as the projects are evaluated and proved reserves established or impairment determined. Pending determination of proved reserves attributable to the above costs, the Company 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 $16.8 million, $7.0 million and $3.2 million for the years ended December 31, 2008, 2007 and 2006, respectively. Depletion per Mcfe was $1.68, $1.28 and $1.07 for the years ended December 31, 2008, 2007 and 2006, respectively.

12. OTHER ASSETS

Other assets consisted of the following:

	As of December 31, 2008	As of December 31, 2007
	(In thousands)	
Deferred financing costs	$46,375	$21,159
Less accumulated amortization	(7,144)	(3,044)
Net deferred financing costs	39,231	18,115
Deferred compensation costs	-	1,003
Deposits	3,008	2,312
Other	772	1,144
	$43,011	$22,574

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

13. ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	As of December 31, 2008	As of December 31, 2007
	(In thousands)	
Accrued operating expenses	$20,296	$14,745
Interest payable	30,713	7,402
Accrued capital expenditures	1,695	11,417
Accrued product purchases	1,382	9,784
Revenue payable	7,181	6,692
Accrued production and property taxes	4,137	3,301
Prepayments from partners	974	732
Environmental liabilities	50	262
Other	495	646
	$66,923	$54,981

14. LONG-TERM DEBT

Long-term debt consisted of the following:

	As of December 31, 2008	As of December 31, 2007
	(In thousands)	
Senior secured credit facility	$ 827,868	$ 310,710
Senior secured second lien facility, net of unamortized discount of $13,050	$ 641,555	-
Senior notes due 2015, net of unamortized discount of $5,938	469,062	-
Senior subordinated notes due 2016	350,000	350,000
Convertible debentures, net of unamortized discount of $1,781 and $1,893	148,219	148,107
KGS Credit Agreement	174,900	5,000
Other loans	-	34
Total debt	2,611,604	813,851
Less current maturities	(6,579)	(34)
Long-term debt	$ 2,605,025	$ 813,817

Maturities are as follows

	Total Indebtedness	Senior Secured Credit Facility	Senior Secured Second Lien Facility	Senior Notes due in 2015	Senior Subordinated Notes	Convertible Debentures	KGS Credit Facility
				(In thousands)			
2009	$ 6,579	$ -	$ 6,579	$ -	$ -	$ -	$ -
2010	6,579	-	6,579	-	-	-	-
2011	6,579	-	6,579	-	-	-	-
2012	1,009,347	827,868	6,579	-	-	-	174,900
2013	628,289	-	628,289	-	-	-	-
Thereafter	975,000	-	-	475,000	350,000	150,000	-
	$ 2,632,373	$ 827,868	$ 654,605	$ 475,000	$ 350,000	$ 150,000	$ 174,900

Senior Secured Credit Facility

The Company's Senior Secured Credit Facility matures February 9, 2012. The facility provides for revolving loans, swingline loans and letters of credit from time to time in an aggregate amount not to exceed the borrowing base, which is calculated based on several factors. The borrowing base is subject to at least annual redeterminations. In September 2008, the lenders agreed to a borrowing base of $1.2 billion. The lenders also agreed to $1.2 billion of revolving credit commitments and, with lender approval, the Company has an option to increase the facility to $1.45 billion. The lenders' commitments under the facility are allocated between U.S. and Canadian funds, with the U.S. currency available for borrowing by U.S. subsidiaries and either U.S. or Canadian currency available for borrowing in Canada. The facility has the option to extend the maturity up to two additional years. U.S. borrowings under the facility are guaranteed by most of Quicksilver's domestic subsidiaries and are secured by, among other things, Quicksilver's and its domestic subsidiaries' oil and gas properties and quantities of proved reserves of natural gas, NGLs and crude oil attributable to them. Canadian borrowings under the facility are guaranteed by Quicksilver and most of Quicksilver's domestic subsidiaries and are secured by, among other things, the Company's Canadian, Quicksilver's and certain of Quicksilver's domestic subsidiaries' oil and gas properties and quantities of proved reserves of natural gas, NGLs and crude oil attributable to them. In 2007, the Company agreed to pledge the equity interests in BBEP it received as part of the BreitBurn Transaction to secure its obligations under the credit facility. At December 31, 2008, the Company had approximately $369 million available borrowing capacity under this facility.

Senior Secured Second Lien Facility

On August 8, 2008, the Company entered into a $700 million five-year senior secured second lien facility ("Senior Secured Second Lien Facility") pursuant to the Alliance Acquisition. Net proceeds were $674.5 million after discount and issuance costs. The Senior Secured Second Lien Facility features LIBOR or ABR rate options with minimum floors plus a spread. On the last day of each quarter, the Company must make a principal payments of $1.6 million which will be adjusted should the Company make unscheduled loan repayments. In connection with the Senior Secured Second Lien Facility, Quicksilver entered into collateral agreements pursuant to which Quicksilver's obligations under the Senior Secured Second Lien Facility, its Senior Notes due 2015 and its domestic subsidiaries' guaranty obligations with respect to the Senior Secured Second Lien Facility and the Senior Notes have been secured equally and ratably by a second lien on substantially all of the assets of Quicksilver and such domestic subsidiaries.

Senior Notes

On June 27, 2008, the Company issued $475 million of Senior Notes due 2015 ("Senior Notes"), which are unsecured, senior obligations of the Company. Interest of 8.25% is payable semiannually on February 1 and August 1. Net proceeds of $457 million after discount and issuance costs were used to pay down balances then outstanding under the senior secured credit facility.

Senior Subordinated Notes

On March 16, 2006, the Company issued the senior subordinated notes due 2016 ("Senior Subordinated Notes"), which are unsecured, senior subordinated obligations of the Company and bear interest at an annual rate of 7.125% payable semiannually on April 1 and October 1.

Convertible Debentures

The convertible debentures due November 1, 2024 are contingently convertible into shares of Quicksilver's 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 the Company to repurchase all or a portion of their debentures on November 1, 2011, 2014 or 2019 at a price equal to the principal amount thereof plus accrued and unpaid interest. The debentures are convertible into Quicksilver 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, holders of the debentures are not entitled to exercise their conversion rights unless the closing price of Quicksilver's stock price 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, the Company has the option to deliver any combination of Quicksilver common stock and cash. Should all debentures be converted to Quicksilver common stock, an additional 9,816,270 shares would become outstanding; however, as of January 1, 2009, the debentures were not convertible.

KGS Credit Agreement

Concurrent with its IPO, KGS entered into a five-year $150 million senior secured revolving credit facility ("KGS Credit Agreement"), with an option exercisable by KGS to extend the facility for up to two additional years. In October of 2008, the lenders increased the facility to $235 million and approved an accordion option of $115 million to allow for future expansion of the facility to $350 million upon lender approval. The KGS Credit Agreement provides for revolving credit loans, swingline loans and letters of credit. Borrowings under the facility are guaranteed by KGS' subsidiaries and are secured by substantially all of the assets of KGS and each of its subsidiaries. The facility features LIBOR and U.S. prime rate interest options for revolving loans and a specified rate for swingline loans. Each interest rate option includes a margin which flexes based upon KGS' leverage ratio.

Summary of All Outstanding Debt

As of December 31, 2008, the Company was in compliance with all covenants associated with its long-term debt, other notes and loans. The following table summarizes significant aspects of our long-term debt:

	Priority of Right to Collateralized Assets [(6)]					***Recourse only to KGS assets***
	Highest priority →				→ **Lowest priority**	
	Senior Secured Credit Facility	**Senior Secured Second Lien Facility**	**Senior Notes**	**Senior Subordinated Notes**	**Convertible Debentures**	**KGS Credit Agreement**
Maturity date	February 9, 2012	August 8, 2013	June 27, 2015	March 16, 2016	November 1, 2024	August 10, 2012
Interest rate at December 31, 2008 [(1)]	3.44%	7.75%	8.25%	7.125%	1.875%	2.90%
Base interest rate options [(5)]	LIBOR, ABR or specified	LIBOR or ABR	N/A	N/A	N/A	LIBOR, ABR or specified
Financial covenants for 2009 [(3)]	- Minimum current ratio of 1.0 - Minimum EBITDA to interest expense ratio of 2.5 - Minimum reserve PV 10 plus 50% of BBEP investment fair value to total debt of 1.5 - Minimum reserve PV 10 plus 50% of BBEP investment fair value to secured debt of 2.0	- Minimum current ratio of 1.0 - Minimum EBITDA to interest expense ratio of 2.25 - Minimum reserve PV 10 plus 50% of BBEP investment fair value to total debt of 1.5 - Minimum reserve PV 10 plus 50% of BBEP investment fair value to secured debt of 2.0	N/A	N/A	N/A	- Maximum debt to EBITDA ratio of 4.5 - Minimum EBITDA to interest expense ratio of 2.5
Financial covenants beyond 2009 [(3)(4)]	- Minimum current ratio of 1.0 - Minimum EBITDA to interest expense ratio of 2.5 - Minimum reserve PV 10 plus 50% of BBEP investment fair value to total debt of 1.5 - Reserve PV 10 plus 50% of BBEP investment fair value to secured debt of 2.25 beginning December 31, 2010	- Minimum current ratio of 1.0 - Minimum EBITDA to interest expense ratio of 2.25 - Minimum reserve PV 10 plus 50% of BBEP investment fair value to total debt of 1.5 - Reserve PV 10 plus 50% of BBEP investment fair value to secured debt of 2.25 beginning December 31, 2010	N/A	N/A	N/A	- Maximum debt to EBITDA ratio of 4.5 - Minimum EBITDA to interest expense ratio of 2.5
Significant restrictive covenants [(3)]	- 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 - 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	N/A	- Incurrence of debt - Incurrence of liens - Equity purchases - Asset sales - Limitations on derivatives
Estimated fair value [(2)]	$827.9 million	$455.0 million	$349.1 million	$187.2 million	$93.8 million	$174.9 million

(1) Represents the weighted average borrowing rate payable to lenders

(2) The estimated fair value is determined based on market quotations on balance sheet date for fixed rate obligations. The Company considers debt with market-based interest rates to have a fair value equal to its carrying value

(3) The covenant information presented in this table is qualified in all respects by reference to the full text of the covenants and related definitions contained in the documents governing the various components of the Company's debt

(4) Represents the most restrictive that each covenant becomes during its period outstanding

(5) Interest rate options include a base rate plus a spread. For the Senior Secured Second Lien Facility the LIBOR rate has a floor of 4.5% and the ABR has a floor of 3.5%

(6) Priority of right to assets is not necessarily the same as priority to receive payments

15. ASSET RETIREMENT OBLIGATIONS

The Company records 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 (a) the passage of time and (b) 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.

The following table provides a reconciliation of the changes in the estimated asset retirement obligation from January 1, 2007 through December 31, 2008.

	As of December 31,	
	2008	2007
	(In thousands)	
Beginning asset retirement obligations	$ 24,510	$ 25,206
Additional liability incurred	8,231	5,239
Change in estimates	4,288	2,385
Accretion expense	1,483	1,509
Sale of properties	-	(11,564)
Asset retirement costs incurred	(359)	(180)
Loss on settlement of liability	119	4
Currency translation adjustment	(3,079)	1,911
Ending asset retirement obligations	35,193	24,510
Less current portion	(440)	(646)
Long-term asset retirement obligation	$ 34,753	$ 23,864

16. INCOME TAXES

In 2006, the Texas business tax was amended by replacing the taxable capital and earned surplus components of the current franchise tax with a new "taxable margin" component. As the tax base for computing Texas margin tax is derived from an income-based measure, the Company recognizes this tax as an income tax. The Company has recorded a deferred tax provision of $1.9 million and $2.5 million for the Texas margin tax in 2008 and 2007, and a current state income tax provision for the Texas margin tax in 2007 of $1.0 million.

Tax rate reductions were enacted during 2007 by the Canadian federal government and by Alberta Province. The Company's Canadian deferred income tax balances were revalued to reflect the changes in these tax rates. The Company recorded $4.9 million of income tax benefits in 2007 as a result of the enactment of Canadian rate reductions. No further rate changes occurred in 2008.

The Company's current and deferred tax positions have been significantly impacted by the November 2007 divestiture of the Northeast Operations and the resulting gain, the impairment of U.S. oil and gas properties in 2008 and the impairment of its investment in BBEP in 2008. Significant components of the Company's deferred tax assets and liabilities as of December 31, 2008 and 2007 are as follows:

	As of December 31,	
	2008	2007
	(In thousands)	
Current		
Deferred tax asset		
Deferred tax benefit on derivative contract loss	$ -	$ 17,258
Deferred tax benefit on cash flow hedge losses	-	1,688
Total current deferred tax assets	$ -	$ 18,946
Deferred tax liabilities		
Deferred tax liability on cash flow hedge gains	$ 52,393	$ -
Non-current		
Deferred tax assets		
Deferred tax benefit on BBEP impairment	$ 112,135	$ -
Deferred tax benefit on derivative contract loss	-	4,973
Deferred tax benefit on deferred compensation expense	4,236	1,506
Minority interest	3,130	624
Deferred tax benefit on cash flow hedge losses	-	617
Net operating loss carry forwards	176,957	-
Other	969	2,336
Total deferred tax assets	297,427	10,056
Deferred tax liabilities		
Property, plant and equipment	470,925	375,427
Deferred tax liability on cash flow hedge gains	40,461	-
Deferred tax liability on convertible debenture interest	11,481	8,693
Other	-	581
Total deferred tax liabilities	522,867	384,701
Net deferred tax liabilities	$ 225,440	$ 374,645

The components of income tax expense for 2008, 2007 and 2006 are as follows:

	2008	2007	2006
		(In thousands)	
Current state income tax expense (benefit)	$ (4)	$ 1,143	$ 11
Current U.S. federal income tax expense	(45,210)	45,394	-
Current Canadian income tax expense	199	28	262
Total current income tax expense (benefit)	(45,015)	46,565	273
Deferred state income tax expense	1,939	2,538	1,600
Deferred U.S. federal income tax expense (benefit)	(188,632)	196,276	27,501
Deferred Canadian income tax expense	22,559	11,129	8,776
Total deferred income tax expense (benefit)	(164,134)	209,943	37,877
Total income tax expense (benefit)	$(209,149)	$ 256,508	$ 38,150

The following table reconciles the statutory federal income tax rate to the effective tax rate for 2008, 2007 and 2006:

	2008	2007	2006
U.S. federal statutory tax rate	35.00%	35.00%	35.00%
Permanent differences	(0.33%)	0.01%	0.16%
State income taxes net of federal deduction	(0.22%)	0.33%	0.80%
FIN 48 recognition	(0.09%)	1.17%	0.00%
Foreign income taxes	1.38%	(1.69)%	(6.29%)
Other	0.13%	0.04%	(0.74%)
Effective income tax rate	35.87%	34.86%	28.93%

The Company incurred a $641 million net operating tax loss in 2008. Approximately $137 million of this loss will be carried back to 2007. The remaining $504 million is included in deferred tax assets at December 31, 2008. The net operating loss will expire in 2028. The net operating loss was not reduced by a valuation allowance, because management believed that future taxable income would more likely than not be sufficient to utilize substantially all of its operating loss tax carry forwards prior to their expiration.

During 2007, the Company recognized $2.8 million in income tax benefits associated with the exercise of employee stock options as an increase to additional paid in capital. No such income tax benefits were recognized in 2008 because of the availability of net operating loss tax carry forwards to the Company.

The Company adopted FIN 48 on January 1, 2007. In connection with the adoption the Company recorded an adjustment to retained earnings of approximately $0.3 million for unrecognized tax benefits, all of which would affect our effective tax rate if recognized. The Company also reported unrecognized tax benefits for research and experimental development credits for Canadian taxes in the first quarter of 2007 of $1.1 million. The following schedule reconciles the total amounts of unrecognized tax benefits for 2008 and 2007.

	As of December 31,	
	2008	2007
	(In thousands)	
Beginning unrecognized tax benefits	$9,997	$ 345
Gross amounts of increases in unrecognized tax benefits as a result of tax positions taken during a prior period	834	1,396
Amount of decreases in unrecognized tax benefits related to settlements with taxing authorities	(1,301)	(1,100)
Gross amounts of increases in unrecognized tax benefits as a result of tax positions taken during the current year	-	9,356
Reductions resulting from the lapse of applicable statutes of limitations	(275)	-
Unrecognized tax benefits	$ 9,255	$ 9,997

Approximately $8.9 million of these unrecognized tax benefits at December 31, 2008, if recognized, would impact the effective tax rate. Interest and penalties of $0.6 million related to unrecognized tax benefits were recognized as interest expense for 2007 and subsequently reversed in 2008. The Company remains subject to examination by the Internal Revenue Service ("IRS") for the years 2001 through 2007 except for 2004. An audit was completed by the IRS for 2004 and the statute of limitations has now expired for this year. The Company does not expect that the total amounts of unrecognized tax benefits will significantly increase or decrease.

17. COMMITMENTS AND CONTINGENCIES

Contractual Obligations.

Information regarding our contractual and scheduled interest obligations, at December 31, 2008, is set forth in the following table.

	Transportation Contracts[1]	Drilling Rig Contracts[2]	Operating Leases[3]	Purchase Obligations[4]
		(In thousands)		
2009	$ 8,768	$ 45,620	$ 3,612	$ 13,800
2010	21,087	19,689	2,122	-
2011	33,406	6,241	1,263	-
2012	45,747	-	478	-
2013	47,473	-	9	-
Thereafter	242,535	-	-	-
Total	$ 399,016	$ 71,550	$ 7,484	$ 13,800

(1) Under contracts with various pipeline companies, the Company is obligated to transport minimum daily gas volumes, as calculated on a monthly basis, or pay for any deficiencies at a specified reservation fee rate. The production committed to the pipelines is expected to meet, or exceed, the daily volumes required under the contracts.

(2) The Company leases 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 $20,000 to $23,200 for the entire lease term regardless of our utilization of the drilling rigs.

(3) The Company leases office buildings and other property under operating leases. Our operating lease obligations include $0.6 million of future lease payments to a company that is owned by members of the Darden family. Rent expense for operating leases with terms exceeding one month was $5.0 million in 2008, $5.2 million in 2007 and $3.5 million in 2006.

(4) At December 31, 2008, KGS was under contract to purchase goods and services for completion of the Corvette Plant and for compressors. Total remaining cash obligations for these goods and services were $13.8 million, including $1.2 million recognized during 2008. KGS placed the Corvette Plant into service during the first quarter of 2009.

Commitments

The Company had commitments outstanding of approximately $3.4 million to purchase components for our drilling program as of December 31, 2008. In addition, the Company had approximately $3.0 million in letters of credit outstanding against the credit facility and approximately $41.3 million in surety bonds issued to fulfill contractual, legal or regulatory requirements. All surety bonds and letters of credit have an annual renewal option.

Contingencies

On November 7, 2001, the Company filed a lawsuit against CMS Marketing Services and Trading Company ("CMS") in Texas. The suit alleged that CMS committed fraud when it entered into a 10-year contract with the Company on March 1, 1999 for the purchase and sale of 10,000 MMBtud of natural gas at a minimum price of $2.47 per MMBtu and breached the contract afterward by failing to comply with a provision of the contract requiring that, if the gas could be scheduled or delivered to derive additional value, the parties would share equally in the additional revenue. On May 15, 2007, the district court entered a final judgment in favor of the Company against CMS ("CMS"), declaring the Company's contract with CMS to be void and rescinded as of that date. CMS appealed this judgment. The Company also appealed seeking to have the contract voided from its inception and seeking to recover jury-awarded punitive damages of $10 million.

Pending final judgment by the appellate court, CMS and the Company agreed to a settlement based upon the decision to be rendered by the appellate court. The settlement agreement specifies that CMS will pay the Company all costs paid by it for all bonds posted on appeal and the Company shall have no obligation under its contract with CMS if the appellate decision affirms the original district court decision. If the appellate court voids the contract from its inception, CMS shall pay the Company $5 million plus all costs paid by the Company for all bonds posted on appeal. If the appellate court reverses the district court judgment, the Company will pay $5 million to CMS. If the appellate court finds that the Company is entitled to punitive damages, CMS will pay the Company $5 million. If the appellate court remands the matter back to the lower courts for any action other than for punitive damages, the parties agreed to forego further adjudication of the matter without payment.

On October 13, 2006, the Company filed suit in district court in Texas against Eagle Drilling, LLC and Eagle Domestic Drilling Operations, LLC (together "Eagle") regarding three contracts for drilling rigs in which the Company alleged that the first rig furnished by Eagle exhibited operating deficiencies and safety defects and that the other rigs failed to conform to specifications set forth in the drilling contracts. On January 19, 2007, Eagle Domestic Drilling Operations, LLC and its parent, Blast Energy Services, Inc. filed for Chapter 11 bankruptcy. The Company's suit against Eagle in Tarrant County was ultimately transferred to the bankruptcy court in Houston and has been consolidated with the Eagle/Blast bankruptcy, described more fully below. On September 17, 2007, Eagle Drilling, LLC, and Rod and Richard Thornton, sued the Company and its Executive Vice President Operations, in district court in Oklahoma for approximately $29 million in damages and an unspecified amount of punitive damages resulting from the Company's repudiation of the rig contracts.

In September 2008, the Company entered into a settlement agreement with Eagle Domestic Drilling Operations, LLC and its parent, Blast Energy Services, Inc. ("Eagle/Blast") that was approved in October by the district court in Texas. Under the settlement agreement, the Company agreed to pay Eagle/Blast $10 million over a three-year period, including $5 million on the settlement date. The Company recorded a $9.6 million charge to general and administrative expense during the quarter ended September 30, 2008 for the net present value of these payments. The other cases involving Eagle and its affiliates were not directly affected by this settlement. Based upon information currently available, the Company believes that the final resolution of this matter will not have a material effect on its financial condition, results of operations, or cash flows.

On October 31, 2008, the Company filed a lawsuit in district court in Texas against BBEP, BreitBurn GP, LLC, BreitBurn Operating L.P., Provident Energy Trust and certain individuals who serve as, or have previously served as, directors and/or officers of these entities (collectively, the "Defendants"). The Company alleges that, among other things, one or more of the Defendants breached the agreement pursuant to which the Company acquired its ownership interest in BBEP, and violated the Texas Securities Act and the Texas Business & Commerce Code, committed common law fraud, fraudulent inducement, negligent misrepresentation and civil conspiracy. The Company has requested, among other things, relief for actual and exemplary damages, and for injunctive and declaratory relief.

18. MINORITY INTEREST

Impact of KGS IPO

As a result of the KGS IPO, the outside ownership of KGS increased, however the Company continues to own 100% of KGS' general partner and, therefore, continues to consolidate KGS into the Company's financial statements. However, by virtue of the elevated outside ownership, the Company's minority interest carrying value is much larger than years prior to KGS' IPO.

Impact of SFAS 160

As described in Note 2, the Company's adoption of SFAS No. 160 on January 1, 2009 resulted in the minority interest liability of $29.9 million being reclassified to stockholders' equity. Measurement of the income statement amounts attributable to non-Quicksilver ownership of KGS is unaffected by adoption of SFAS No. 160.

19. 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. The Company makes matching contributions and a fixed annual contribution and has the ability to make discretionary contributions to the plan. Expenses associated with company contributions were \$2.4 million, \$1.6 million and \$1.4 million for 2008, 2007 and 2006, respectively.

The Company has a retirement plan available to all Canadian employees. The plan provides for a match of employees' contributions by the Company and a fixed annual contribution. Expenses associated with company contributions were \$0.8 million, \$0.7 million and \$0.5 million for the 2008, 2007 and 2006, respectively.

The Company maintains 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. Quicksilver is responsible for payment of the first \$75,000 for each individual claim and also purchased aggregate level reinsurance for payment of claims up to \$1 million over the estimated maximum claim liability. For 2008, 2007 and 2006 the Company recognized expenses of \$4.4 million, \$3.2 million and \$2.5 million, respectively, for this plan.

20. STOCKHOLDERS' EQUITY

Common Stock, Preferred Stock and Treasury Stock

The Company is authorized to issue 400 million shares of common stock with a par value per share of one cent and 10 million shares of preferred stock with a par value per share of one cent. At December 31, 2008, the Company had 167,169,904 shares of common stock outstanding.

The following table shows common share and treasury share activity since January 1, 2006:

	Common Shares Issued	Treasury Shares Held
Opening balance at January 1, 2006	154,729,151	2,571,069
Stock options exercised	2,212,190	-
Restricted stock activity	842,174	8,602
Balance at December 31, 2006	157,783,515	2,579,671
Stock options exercised	2,257,840	-
Restricted stock activity	591,915	37,055
Balance at December 31, 2007	160,633,270	2,616,726
Stock issuance	10,400,468	-
Stock repurchase	-	1,885,600
Stock options exercised	249,732	-
Restricted stock activity	459,229	70,469
Balance at December 31, 2008	171,742,699	4,572,795

Stockholder Rights Plan

In 2003, the Company's Board of Directors declared a dividend distribution of one preferred share purchase right for each outstanding share of common stock then outstanding. Each right, when it becomes exercisable, entitles stockholders to buy one one-thousandth of a share of the Company'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 the common stock of Quicksilver 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 the common stock of the Company. 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 the Company's common stock at December 31, 2008.

If an Acquiring Person acquires 15% or more of the outstanding common stock of the Company, each right will entitle its holder to purchase, at the right's then-current exercise price, a number of common shares of the Company having a market value of twice such price. If Quicksilver is acquired in a merger or other business combination transaction after an Acquiring Person has acquired 15% or more of the outstanding common stock of the Company, 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 the common stock of Quicksilver, the rights are redeemable for $0.01 per right at the option of the Board of Directors of the Company.

Employee Stock Plans

1999 and 2004 Plans

In 1999, the Board of Directors adopted the Company's 1999 Stock Option and Retention Stock Plan (the "1999 Plan"), which was approved at the annual stockholders' meeting held in June 2000. Under the 1999 Plan, 7.8 million shares of common stock could be issued via incentive stock options, non-qualified stock options, stock appreciation rights and retention stock awards. Pursuant to an amendment approved at the annual shareholders meeting held in May 2004, an additional 7.2 million shares were reserved for issuance pursuant to the 1999 Plan. As of December 31, 2008, a total of 219,321 shares and 193,842 options to purchase shares granted under the 1999 plan remain unvested.

In February 2004, the Board of Directors adopted the Company's 2004 Non-Employee Director Equity Plan (the "2004 Plan"), which was approved at the annual stockholders' meeting held in May 2004. There were 1.5 million shares reserved under the 2004 Plan, which permits issuance of non-qualified options and restricted stock awards to Quicksilver's non-employee directors.

Under terms of the 1999 Plan and 2004 Plan, equity awards to officers, employees and non-employee directors reflect an exercise price of not less than the fair market value on the date of grant. Incentive stock options and non-qualified options' lives may not exceed ten years from date of grant. Although shares were still available for issuance under the 1999 and 2004 Plans, in approving the 2006 Equity Plan, the Company agreed to make no further issuances under these plans.

2006 Equity Plan

In 2006, the Board of Directors and the shareholders approved the Company's 2006 Equity Plan. Upon approval of the 2006 Equity Plan, 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. Executive officers, other employees, consultants and non-employee directors of the Company are eligible to participate in the 2006 Equity Plan. Under the 2006 Equity Plan, options reflect an exercise price of not less than the fair market value on the date of grant and have a life of 10 years. At December 31, 2008, 12,176,203 shares (including 107,482 shares surrendered to the Company to satisfy participants' tax withholding obligations which then became available for future issuance under the 2006 Equity Plan) of common stock were available for issuance under the 2006 Equity Plan.

Stock Options Under All Plans

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

	2008	2007	2006
Wtd avg grant date fair value	$13.67	N/A	$12.50
Wtd avg grant date	Jan 2, 2008	N/A	Jan 3, 2006
Wtd avg risk-free interest rate	3.41%	N/A	4.35%
Expected life (in years)	6.0	N/A	10.0
Wtd avg volatility	40.2%	N/A	37.3%
Expected dividends	-	N/A	-

The following table summarizes the Company's stock option activity for 2008:

	Shares	Wtd Avg Exercise Price	Wtd Avg Remaining Contractual Life	Aggregate Intrinsic Value
				(In thousands)
Outstanding at January 1, 2008	1,021,912	$ 7.48		
Granted	373,382	30.95		
Exercised	(249,732)	4.98		
Cancelled	(42,226)	28.20		
Outstanding at December 31, 2008	1,103,336	$ 14.20	3.7	$ 39
Exercisable at December 31, 2008	572,710	$ 7.29	1.6	$ 26

The Company estimates that a total of 1,086,497 stock options will become vested including those options already exercisable. These options have a weighted average exercise price of $13.94 and a weighted average remaining contractual life of 3.7 years.

Compensation expense related to stock options of $1.6 million and $0.1 million was recognized for 2008 and 2007, respectively. Cash received from the exercise of stock options totaled $1.2 million, $21.4 million and $19.7 million for the years 2008, 2007 and 2006, respectively. The total intrinsic value of options exercised during 2008, 2007 and 2006, was $6.7 million, $30.5 million and $26.9 million, respectively.

Restricted Stock Under All Plans

The following table summarizes the Company's restricted stock and stock unit activity for 2008:

	Shares	Wtd Avg Grant Date Fair Value
Outstanding at January 1, 2008	1,340,122	$18.76
Granted	628,196	30.67
Vested	(484,428)	30.94
Cancelled	(147,779)	22.82
Outstanding at December 31, 2008	1,336,111	$24.01

At December 31, 2007, the Company had unvested compensation cost of $15.2 million. During 2008, $13.5 million of compensation expense was recognized for restricted stock and stock units. As of December 31, 2008, the unrecognized compensation cost related to outstanding unvested restricted stock was $17.6 million, which is expected to be recognized in expense over the next twelve months. For 2007 and 2006, compensation expense of $11.0 million and $5.8 million, respectively, was recognized.

The total fair value of shares vested during 2008, 2007 and 2006 was $15.1 million, $6.4 million and $2.1 million, respectively.

KGS Restricted Phantom Units

Awards of phantom units have been granted under KGS' 2007 Equity Plan, which permits the issuance of up to 750,000 units. The following table summarizes information regarding the phantom unit activity:

	Payable in cash		Payable in units	
	Shares	Date Fair	Shares	Date Fair
Outstanding at January 1, 2008	84,961	$ 21.36	9,833	$ 21.36
Granted	6,605	24.12	137,148	25.25
Vested	(28,247)	21.43	(6,089)	21.36
Cancelled	(3,000)	21.36	(974)	25.25
Outstanding at December 31, 2008	60,319	$ 21.63	139,918	$ 25.15

At January 1, 2008, KGS had total unvested compensation cost of $1.9 million related to unvested phantom units. KGS recognized compensation expense of approximately $1.4 million during 2008, including $0.4 million for remeasuring awards to be settled in cash to their revised fair value. Grants of phantom units during the year ended December 31, 2008 had an estimated grant date fair value of $3.6 million. KGS has unearned compensation of $2.3 million which will be recognized in expense over the next 1.9 years. Phantom units that vested during the year ended December 31, 2008 had a fair value of $0.7 million.

21. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The following subsidiaries of Quicksilver are guarantors of Quicksilver's Senior Subordinated Notes: Cowtown Pipeline Funding, Inc., Cowtown Pipeline Management, Inc., Cowtown Pipeline LP, and Cowtown Gas Processing, LP (collectively, the "Guarantor Subsidiaries"). Each of the Guarantor Subsidiaries is 100% owned by Quicksilver. The guarantees are full and unconditional and joint and several. The condensed consolidating financial statements below present the financial position, results of operations and cash flows of Quicksilver, the Guarantor Subsidiaries and non-guarantor subsidiaries of Quicksilver.

As part of the BreitBurn Transaction, Quicksilver sold its interests in Mercury Michigan, Inc., Terra Energy Ltd., GTG Pipeline Corporation, Terra Pipeline Company and Beaver Creek Pipeline, LLC, each of which had been a guarantor of Quicksilver's Senior Subordinated Notes.

Condensed Consolidating Balance Sheets

	December 31, 2008				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
			(In thousands)		
ASSETS					
Current assets	$ 423,487	$ 163	$ 426,297	$ (456,611)	$ 393,336
Property and equipment	2,756,915	1,774	1,039,026	-	3,797,715
Investment in subsidiaries (equity method)	596,149	170,150	-	(615,796)	150,503
Other assets	209,837	123,298	2,826	(176,944)	159,017
Total assets	$ 3,986,388	$ 295,385	$ 1,468,149	$ (1,249,351)	$ 4,500,571

	December 31, 2008				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
			(In thousands)		
LIABILITIES AND STOCKHOLDERS EQUITY					
Current liabilities	$ 518,836	$ 122,677	$ 233,597	$ (456,611)	$ 418,499
Long-term liabilities	2,372,843	-	682,281	(176,944)	2,878,180
Deferred gain	-	-	29,867	-	29,867
Minority interest	-	-	79,316	-	79,316
Stockholders' equity	1,094,709	172,708	443,088	(615,796)	1,094,709
Total liabilities and stockholders' equity	$ 3,986,388	$ 295,385	$ 1,468,149	$ (1,249,351)	$ 4,500,571

	December 31, 2007				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
			(In thousands)		
ASSETS					
Current assets	$ 213,288	$ 596	$ 243,086	$ (266,569)	$ 190,401
Property and equipment	1,294,573	1,858	845,915	-	2,142,346
Investment in subsidiaries (equity method)	819,119	160,825	-	(559,773)	420,171
Other assets	72,426	82,251	2,171	(133,920)	22,928
Total assets	$ 2,399,406	$ 245,530	$ 1,091,172	$ (960,262)	$ 2,775,846
LIABILITIES AND STOCKHOLDERS EQUITY					
Current liabilities	$ 470,690	$ 77,529	$ 76,925	$ (266,569)	$ 358,575
Long-term liabilities	860,361	-	512,821	(133,920)	1,239,262
Deferred gain	-	-	79,316	-	79,316
Minority interest	-	-	30,338	-	30,338
Stockholders' equity	1,068,355	168,001	391,772	(559,773)	1,068,355
Total liabilities and stockholders' equity	$ 2,399,406	$ 245,530	$ 1,091,172	$ (960,262)	$ 2,775,846

Condensed Consolidating Statements of Income

	December 31, 2008				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
			(In thousands)		
Revenues	$ 600,906	$ 514	$ 261,616	$ (62,395)	$ 800,641
Operating expenses	976,984	11,157	124,592	(62,395)	1,050,338
Equity in net earnings of subsidiaries	81,948	21,762	-	(103,710)	-
Operating income (loss)	(294,130)	11,119	137,024	(103,710)	(249,697)
Income from earnings of BBEP	93,298	-	-	-	93,298
Impairment of investment in BBEP	(320,387)	-	-	-	(320,387)
Interest expense and other	(83,069)	6,023	(29,311)	-	(106,357)
Income tax (expense) benefit	230,294	1,617	(22,762)	-	209,149
Net income	$ (373,994)	$ 18,759	$ 84,951	$ (103,710)	$ (373,994)

	December 31, 2007				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
			(In thousands)		
Revenues	$ 367,894	$ -	$ 223,281	$ (29,917)	$ 561,258
Operating expenses	241,174	601	111,664	(29,917)	323,522
Income from equity affiliates	14	-	647	-	661
Gain on sale of properties	628,709	-	-	-	628,709
Loss on natural gas supply contracts	(63,525)	-	-	-	(63,525)
Equity in net earnings of subsidiaries	76,060	7,407	-	(83,467)	-
Operating income	767,978	6,806	112,264	(83,467)	803,581
Interest expense and other	(50,077)	2,418	(20,036)	-	(67,695)
Income tax expense	(238,523)	(636)	(17,349)	-	(256,508)
Net income	$ 479,378	$8,588	$ 74,879	$ (83,467)	$ 479,378

	December 31, 2006				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
			(In thousands)		
Revenues	$ 233,757	$ 3,046	$ 157,491	$ (3,932)	$ 390,362
Operating expenses	148,613	2,635	69,376	(3,932)	216,692
Income from equity affiliates	17	-	509	-	526
Equity in net earnings of subsidiaries	58,543	-	-	(58,543)	-
Operating income	143,704	411	88,624	(58,543)	174,196
Interest expense and other	(29,766)	-	(12,561)	-	(42,327)
Income tax expense	(20,219)	(144)	(17,787)	-	(38,150)
Net income	$ 93,719	$ 267	$ 58,276	$ (58,543)	$ 93,719

Condensed Consolidating Statements of Cash Flows

	December 31, 2008				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
			(In thousands)		
Cash flow provided by operations	$ 211,519	$ 9,684	$ 235,363	$ -	$ 456,566
Cash flow used for investing activities	(1,875,307)	50,596	(370,311)	(83,566)	(2,278,588)
Cash flow provided by financing activities	1,638,387	(60,280)	135,080	83,566	1,796,753
Effect of exchange rates on cash	68	-	(177)	-	(109)
Net increase (decrease) in cash & equivalents	(25,333)	-	(45)	-	(25,378)
Cash and equivalents at beginning of period	27,010	-	1,216	-	28,226
Cash and equivalents at end of period	$ 1,677	$ -	$ 1,171	$ -	$ 2,848

	December 31, 2007				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
			(In thousands)		
Cash flow provided by operations	$ 146,348	$ (354)	$ 173,110	$ -	$ 319,104
Cash flow used for investing activities	(18,471)	47,047	(283,940)	(14,388)	(269,752)
Cash flow provided by financing activities	(101,541)	(46,693)	101,570	14,388	(32,276)
Effect of exchange rates on cash	591	-	5,278	-	5,869
Net increase (decrease) in cash & equivalents	26,927	-	(3,982)	-	22,945
Cash and equivalents at beginning of period	83	-	5,198	-	5,281
Cash and equivalents at end of period	$ 27,010	$ -	$ 1,216	$ -	$ 28,226

	December 31, 2006				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
			(In thousands)		
Cash flow provided by operations	$ 207,097	$ (45,073)	$ 80,162	$ -	$ 242,186
Cash flow used for investing activities	(523,750)	(81,534)	(257,016)	250,275	(612,025)
Cash flow provided by financing activities	307,746	126,607	177,233	(250,275)	361,311
Effect of exchange rates on cash	-	-	(509)	-	(509)
Net increase (decrease) in cash & equivalents	(8,907)	-	(130)	-	(9,037)
Cash and equivalents at beginning of period	8,990	-	5,328	-	14,318
Cash and equivalents at end of period	$ 83	$ -	$ 5,198	$ -	$ 5,281

22. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid for interest and income taxes is as follows:

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Interest	$83,400	$69,038	$37,627
Income taxes	49,433	-	3

Other significant non-cash transactions are as follows:

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Working capital related to capital expenditures	$230,624	$ 159,819	$ 118,359
Issuance of common stock as consideration for the Alliance Acquisition	262,092	-	-
Noncash interest in BBEP earnings	-	429,618	-
Tax benefit recognized on employee stock option exercises	-	2,755	-

23. RELATED PARTY TRANSACTIONS

As of December 31, 2008, members of the Darden family and entities controlled by them beneficially owned approximately 30% of the Company's outstanding common stock. Thomas Darden, Glenn Darden and Anne Darden Self are officers and directors of the Company.

Quicksilver paid $1.9 million, $2.1 million and $1.8 million in 2008, 2007 and 2006, respectively, for rent on buildings owned by entities controlled by members of the Darden family. Rental rates were determined based on comparable rates charged by third parties. At December 31, 2008, the Company had future lease obligations of $0.6 million through 2010 to these entities.

During 2008, 2007 and 2006, the Company paid $0.9 million, $0.2 million and $0.4 million for use of an airplane owned by an entity controlled by member of the Darden family. Usage rates were determined based upon comparable rates charged by third parties.

Payments received in 2008, 2007 and 2006 from Mercury for sublease rentals, employee insurance coverage and administrative services were $0.3 million, $0.2 million and $0.1 million, respectively.

In October 2008, the Company paid $19.9 million for the purchase of 1,885,600 share of its common stock from an entity controlled by members of the Darden family.

In October 2008, the Company completed the purchase of its headquarters building in Fort Worth, Texas for $6.4 million, the estimated fair value of the building, from an entity controlled by members of the Darden family. Subsequently, the Company entered into a property management agreement with an affiliate of the seller to which the Company paid $14,000 during the remainder of 2008. Annual lease payments on the purchased building prior to acquisition had been $1.1 million.

In May 2008, the Company signed a settlement agreement with Mercury in which Mercury agreed to make a payment of approximately $0.4 million in connection with issues related to the ownership and operation of certain oil and gas properties acquired from Mercury in 2001, including audit claims received with respect to certain of the acquired properties and the administration of employee benefits.

In 2006, Quicksilver leased over 5,000 acres from a related party entity, "KC7," in exchange for $0.7 million. Under the terms of the leases, either a 3% overriding royalty interest or a 20% royalty interest was granted to KC7. The lease terms were determined based on comparable prices and terms granted to third parties with respect to similar leases in the area. Aggregate payments to KC7 in 2007 were $0.2 million, respectively. No payments were made to KC7 in 2008.

24. SEGMENT INFORMATION

The Company operates in two geographic segments, the United States and Canada, where it is engaged in the exploration and production segment of the oil and gas industry. Additionally, the Company operates in the U.S. midstream segment, where it provides natural gas processing and gathering services to the oil and gas industry, predominately through KGS. Revenue earned by KGS for the processing and gathering of Quicksilver gas are eliminated on a consolidated basis as are the costs of these services recognized by Quicksilver's producing properties. The Company evaluates performance based on operating income and property and equipment costs incurred.

	Exploration & Production		Processing &			Quicksilver
	United States	Canada	Gathering	Corporate	Elimination	Consolidated
			(In thousands)			
2008						
Revenues	$ 600,292	$ 187,740	$ 78,572	$ -	$ (65,963)	$ 800,641
Depletion, depreciation and accretion	127,010	44,948	15,134	1,104	-	188,196
Impairment related to oil and gas properties	624,315	-	9,200	-	-	633,515
Operating income (loss)	(321,756)	104,131	34,879	(66,951)	-	(249,697)
Property, plant and equipment - net	2,723,103	550,413	519,447	4,752	-	3,797,715
Property and equipment costs incurred	2,179,815	138,360	265,222	1,638	-	2,585,035
2007						
Revenues	$ 396,768	$ 158,121	$ 35,941	$ -	$ (29,572)	$ 561,258
Depletion, depreciation and accretion	72,132	39,445	8,146	974	-	120,697
Operating income	750,703	85,155	12,380	(44,657)	-	803,581
Property, plant and equipment - net	1,290,728	571,496	275,807	4,315	-	2,142,346
Property and equipment costs incurred	758,601	115,073	168,523	2,017	-	1,044,214
2006						
Revenues	$ 272,377	$ 116,726	$ 13,907	$ -	$ (12,648)	$ 390,362
Depletion, depreciation and accretion	45,810	29,225	2,998	767	-	78,800
Operating income	133,521	63,906	3,173	(26,404)	-	174,196
Property, plant and equipment - net	1,126,351	417,199	132,457	3,273	-	1,679,280
Property and equipment costs incurred	439,986	118,028	85,848	1,865	-	645,727

25. SUPPLEMENTAL INFORMATION (UNAUDITED)

Proved oil and gas reserves estimates for the Company's properties in the United States 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 and utilized existing economic and operating conditions. Natural gas, NGL and crude oil prices in effect as of the date of the reserve reports were used without any escalation except in those instances where the sale of production was covered by contract, in which case the applicable contract prices, including fixed and determinable escalations, were used for the duration of the contract, and thereafter the year-end price was used. Operating costs, production and ad valorem taxes and future development costs were based on current 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 represents estimates only and should not be construed as being exact. Moreover, the present values should not be construed as the current market value of the Company's natural gas and crude oil reserves or the costs that would be incurred to obtain equivalent reserves.

As further discussed in Note 2, the Company records its equity earnings from its investment in BBEP in the period in which BBEP makes such information publicly available because the Company does not control BBEP and believes that BBEP is not an "affiliate" (as defined in the SEC rules) of the Company. As a result, the Company's 2008 consolidated financial statements reflect BBEP's results of operations from November 1, 2007, when the Company acquired the BBEP units, through September 30, 2008. The disclosures in this note relating to BBEP, however, reflect the Company's pro rata portion of the supplemental oil and gas information disclosed by BBEP as of and for the period ended December 31, 2008 in their 2008 annual report.

The changes in proved reserves for the three years ended December 31, 2008 were as follows:

	Natural Gas (MMcf)			NGL (MBbl)			Crude Oil (MBbl)		
	United States	Canada	Total	United States	Canada	Total	United States	Canada	Total
December 31, 2005	716,043	304,910	1,020,953	9,623	-	9,623	5,915	-	5,915
Revisions	(80,484)	(32,938)	(113,422)	4,593	7	4,600	667	-	667
Extensions and discoveries	332,811	55,006	387,817	34,510	14	34,524	320	-	320
Sales in place	-	(405)	(405)	-	-	-	-	-	-
Production	(35,028)	(18,238)	(53,266)	(741)	(5)	(746)	(587)	-	(587)
December 31, 2006 [1]	933,342	308,335	1,241,677	47,985	16	48,001	6,315	-	6,315
Revisions	(30,494)	17,761	(12,733)	1,112	(1)	1,111	633	-	633
Extensions and discoveries	302,098	24,463	326,561	46,571	-	46,571	658	-	658
Sales in place [2]	(503,651)	(1,446)	(505,097)	(3,147)	-	(3,147)	(3,947)	-	(3,947)
Production	(38,887)	(20,732)	(59,619)	(2,466)	(5)	(2,471)	(584)	-	(584)
December 31, 2007 [1]	662,408	328,381	990,789	90,055	10	90,065	3,075	-	3,075
Revisions	(171,009)	4,923	(166,086)	(25,596)	-	(25,596)	(106)	-	(106)
Extensions and discoveries	560,205	22,363	582,568	31,662	-	31,662	428	-	428
Purchases in place	299,952	-	299,952	-	-	-	-		-
Sales in place	-	(27)	(27)	-	-	-	-	-	-
Production	(45,059)	(23,069)	(68,128)	(4,194)	(2)	(4,196)	(483)	-	(483)
December 31, 2008 [1]	1,306,497	332,571	1,639,068	91,927	8	91,935	2,914	-	2,914
Proved developed reserves									
December 31, 2006	626,582	217,759	844,341	18,771	16	18,787	5,236	-	5,236
December 31, 2007	379,917	260,029	639,946	50,738	10	50,748	2,763	-	2,763
December 31, 2008	756,191	278,668	1,034,859	56,181	8	56,189	2,509	-	2,509

(1) Although the Company did not acquire its initial 32% limited partnership interest in BBEP until 2007, had the Company owned 32% of BBEP at December 31, 2006, proportionate ownership of BBEP would have included 1,341 MMcf of natural gas and 9,613 MBbl of crude oil, all within the United States but none of which is included in the above table. At December 31, 2007, the Company's 32% ownership of BBEP represented proved oil and gas reserves of 160,880 MMcf of natural gas and 18,505 MBbl of crude oil, all within the United States but none of which is included in the above table. At December 31, 2008, the Company's 41% ownership of BBEP represented proved oil and gas reserves of 189,176 MMcf of natural gas and 10,509 MBbl of crude oil, all within the United States but none of which is included in the above table.

(2) Sales of reserves in place during 2007 relate principally to the BreitBurn Transaction, which is more fully described in Note 5

The carrying value of oil and gas assets as of December 31, 2008, 2007 and 2006 were as follows:

	United States	Canada	Consolidated
		(In thousands)	
2008			
Proved properties	$ 3,068,326	$ 553,505	$ 3,621,831
Unevaluated properties	462,943	80,590	543,533
Accumulated DD&A	(902,281)	(120,475)	(1,022,756)
Net capitalized costs [1]	$ 2,628,988	$ 513,620	$ 3,142,608
2007			
Proved properties	$ 1,231,109	$ 580,186	$ 1,811,295
Unevaluated properties	163,274	51,954	215,228
Accumulated DD&A	(157,122)	(105,001)	(262,123)
Net capitalized costs [1]	$ 1,237,261	$ 527,139	$ 1,764,400
2006			
Proved properties	$ 1,163,353	$ 397,106	$ 1,560,459
Unevaluated properties	157,220	34,445	191,665
Accumulated DD&A	(250,547)	(57,518)	(308,065)
Net capitalized costs [1]	$ 1,070,026	$ 374,033	$ 1,444,059

(1) Although the Company did not acquire its initial 32% limited partnership interest in BBEP until 2007, had the Company owned 32% of BBEP at December 31, 2006, proportionate ownership of BBEP would have included $59.3 million of capitalized oil and gas costs, all within the United States but none of which is included in the above table. At December 31, 2007, the Company's 32% ownership of BBEP represented $593.8 million of capitalized oil and gas costs, all within the United States but none of which is included in the above table. At December 31, 2008, the Company's 41% ownership of BBEP represented $743.8 million of capitalized oil and gas costs, all within the United States but none of which is included in the above table.

Capital expenditures for exploration and development activities during each of the three years ended December 31, 2008, were as follows:

	United States	Canada	Consolidated
		(In thousands)	
2008			
Proved acreage	$ 787,172	$ -	$ 787,172
Unproved acreage	484,770	54,048	538,818
Development costs	836,032	68,629	904,661
Exploration costs	30,161	10,280	40,441
Total (1)	$2,138,135	$132,957	$2,271,092
2007			
Proved acreage	$ -	$ -	$ -
Unproved acreage	17,031	31,448	48,479
Development costs	648,632	67,608	716,240
Exploration costs	75,862	11,953	87,815
Total (1)	$ 741,525	$111,009	$ 852,534
2006			
Proved acreage	$ -	$ -	$ -
Unproved acreage	32,048	1,574	33,622
Development costs	121,104	82,378	203,482
Exploration costs	280,438	27,197	307,635
Total (1)	$ 433,590	$111,149	$ 544,739

(1) Although the Company did not acquire its initial 32% limited partnership interest in BBEP until 2007, had the Company owned 32% of BBEP at December 31, 2006, proportionate ownership of BBEP would have included $12.2 million of capitalized expenditures for exploration and development, all within the United States but none of which is included in the above table. At December 31, 2007, the Company's 32% ownership of BBEP represented $551.0 million of costs incurred for exploration and development, all within the United States but none of which is included in the above table. At December 31, 2008, the Company's 41% ownership of BBEP represented $49.6 million of costs incurred for exploration and development, all within the United States but none of which is included in the above table.

Results of operations from producing activities for the three years ended December 31, 2008, are set forth below:

	United States	Canada	Consolidated
		(In thousands)	
2008			
Natural gas, NGL and crude oil sales	$ 597,889	$182,899	$ 780,788
Oil & gas production expense	113,793	38,662	152,455
Depletion & amortization expense	120,845	40,337	161,182
Impairment related to oil and gas properties	624,315	-	624,315
	(261,064)	103,900	(157,164)
Income tax expense (benefit)	(91,372)	30,131	(61,241)
Results from producing activities[(1)]	$(169,692)	$ 73,769	$ (95,923)
2007			
Natural gas, NGL and crude oil sales	$ 392,841	$152,248	$ 545,089
Oil & gas production expense	119,452	33,521	152,973
Depletion & amortization expense	65,701	35,330	101,031
	207,688	83,397	291,085
Income tax expense	72,691	24,185	96,876
Results from producing activities[(1)]	$ 134,997	$ 59,212	$ 194,209
2006			
Natural gas, NGL and crude oil sales	$ 270,535	$116,005	$ 386,540
Oil & gas production expense	87,199	23,596	110,795
Depletion & amortization expense	40,760	26,094	66,854
	142,576	66,315	208,891
Income tax expense	49,902	19,231	69,133
Results from producing activities[(1)]	$ 92,674	$ 47,084	$ 139,758

(1) Although the Company did not acquire its initial 32% limited partnership interest in BBEP until 2007, had the Company owned 32% of BBEP at December 31, 2006, proportionate ownership of BBEP would have included $25.0 million of producing activity results, all within the United States but none of which is included in the above table. For 2007, the Company's 32% ownership of BBEP represented a loss of $7.8 million for producing activity results including realized and unrealized hedging gains and losses, all within the United States but none of which is included in the above table. At December 31, 2008, the Company's 41% ownership of BBEP represented income of $214.1 million for producing activity results including realized and unrealized hedging gains and losses, all within the United States but none of which is included in the above table.

The Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves ("Standardized Measure") do not purport to present the fair market value of the Company's natural gas and crude oil properties. An estimate of such value should consider, among other factors, anticipated future prices of natural gas and crude oil, the probability of recoveries in excess of existing proved reserves, the value of probable reserves and acreage prospects, 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 were estimated by applying year-end prices, adjusted for contracts with price floors but excluding hedges, 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,		
	2008	2007	2006
Natural gas - Henry Hub-Spot	$ 5.71	$ 6.80	$ 5.64
Natural gas - AECO	5.44	6.35	5.39
NGL - Mont Belvieu, Texas	21.65	57.35	40.10
NGL - Kalkaska, Michigan (1)	N/A	N/A	37.73
Crude oil - WTI Cushing	44.60	95.98	60.85

(1) All Michigan NGL reserves were sold in 2007 pursuant to the BreitBurn Transaction, which is more fully described in Note 5

Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pretax cash inflows. Future income taxes were computed by applying the statutory tax rate to the excess of pretax cash inflows over the Company's tax basis in the associated proved natural gas and crude 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 of discounted cash flows related to proved oil and gas reserves at December 31, 2008, 2007 and 2006 were as follows:

	United States	Canada	Total
		(In thousands)	
December 31, 2008			
Future revenues	$ 8,783,936	$1,764,268	$10,548,204
Future production costs	(4,162,737)	(551,395)	(4,714,132)
Future development costs	(1,140,466)	(113,800)	(1,254,266)
Future income taxes	(504,753)	(215,212)	(719,965)
Future net cash flows	2,975,980	883,861	3,859,841
10% discount	(1,623,862)	(441,717)	(2,065,579)
Standardized measure of discounted future cash flows relating to proved reserves (1)	$ 1,352,118	$ 442,144	$ 1,794,262
December 31, 2007			
Future revenues	$ 9,566,791	$2,037,478	$11,604,269
Future production costs	(3,286,618)	(675,890)	(3,962,508)
Future development costs	(651,802)	(156,289)	(808,091)
Future income taxes	(1,772,021)	(228,883)	(2,000,904)
Future net cash flows	3,856,350	976,416	4,832,766
10% discount	(2,168,150)	(495,413)	(2,663,563)
Standardized measure of discounted future cash flows relating to proved reserves (1)	$ 1,688,200	$ 481,003	$ 2,169,203
December 31, 2006			
Future revenues	$ 7,388,886	$1,629,456	$ 9,018,342
Future production costs	(2,715,746)	(550,148)	(3,265,894)
Future development costs	(464,997)	(148,850)	(613,847)
Future income taxes	(1,268,907)	(197,885)	(1,466,792)
Future net cash flows	2,939,236	732,573	3,671,809
10% discount	(1,813,746)	(372,238)	(2,185,984)
Standardized measure of discounted future cash flows relating to proved reserves (1)	$ 1,125,490	$ 360,335	$ 1,485,825

(1) Although the Company did not acquire its initial 32% limited partnership interest in BBEP until 2007, had the Company owned 32% of BBEP at December 31, 2006, proportionate ownership of BBEP would have

included $100.0 million of discounted future cash flows, all within the United States but none of which is included in the above table. For 2007, the Company's 32% ownership of BBEP represented $609.2 million of discounted future cash flows, all within the United States, but none of which is included in the above table. At December 31, 2008, the Company's 41% ownership of BBEP represented $240.2 million of discounted future cash flows related to its proved oil and gas reserves, all within the United States but none of which is included in the above table.

The primary changes in the standardized measure of discounted future net cash flows for the three years ended December 31, 2008, were as follows:

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Sales of oil and gas net of production costs	$ (628,333)	$ (392,116)	$ (275,745)
Net changes in price and production cost	(2,368,940)	1,048,432	(1,236,793)
Extensions and discoveries	1,630,418	1,045,296	661,033
Development costs incurred	373,124	170,686	78,063
Changes in estimated future development costs	(413,097)	(234,649)	42,015
Purchase and sale of reserves, net	722,662	(1,008,566)	(1,977)
Revision of estimates	(618,527)	(8,090)	(94,080)
Accretion of discount	324,064	196,275	260,340
Net change in income taxes	509,854	(293,374)	302,342
Timing and other differences	93,834	159,484	(73,505)
Net increase (decrease)	$ (374,941)	$ 683,378	$ (338,307)

26. SELECTED QUARTERLY DATA (UNAUDITED)

	Quarter Ended			
	March 31	June 30	September 30	December 31
		(In thousands, except per share data)		
2008 (1)				
Operating revenues	$ 157,503	$ 198,015	$ 236,262	$ 208,861
Operating income	70,609	107,217	119,990	(547,513)
Net income (loss)	42,176	52,396	(2,675)	(465,891)
Basic net earnings (loss) per share	$ 0.27	$ 0.33	$ (0.02)	$ (2.79)
Diluted net earnings (loss) per share	0.25	0.31	(0.02)	(2.79)
2007 (2)				
Operating revenues	$ 116,580	$ 136,398	$ 159,199	$ 149,081
Operating income	48,560	61,975	63,574	629,472
Net income	22,851	31,731	28,719	396,077
Basic net earnings per share	$ 0.15	$ 0.20	$ 0.18	$ 2.53
Diluted net earnings per share	0.14	0.19	0.17	2.35

(1) Operating loss for the fourth quarter of 2008 includes a charge of $633.5 million for the impairment related to the Company's U.S. oil and gas properties. Net loss for the fourth quarter of 2008 also includes $93.3 million for pretax income attributable to the Company's proportionate ownership of BBEP and a pretax charge of $320.4 million for impairment of the related investment, respectively.

(2) Operating income and net income for the fourth quarter of 2007 includes a gain of $628.6 million recognized from the divestiture of the Company's Northeast Operations and a charge of $63.5 million for the remaining contract period of the Michigan Sales Contract.

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, 2008.

Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective at the reasonable assurance level as of December 31, 2008.

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, 2008, 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, 2008, our internal control over financial reporting was effective.

The effectiveness of our internal control over financial reporting as of December 31, 2008, has been audited by Deloitte & Touche LLP, our independent registered public accounting firm, and they have issued an attestation report expressing an unqualified opinion 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 2008 that has materially affected, or is reasonably likely to affect, our internal control over financial reporting.

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, 2008, 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.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, 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, 2008 of the Company and our report dated March 2, 2009 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Fort Worth, Texas
March 2, 2009

ITEM 9B. Other Information

None.

PART III

ITEM 10. Directors, Executive Officers and Corporate Governance

The information concerning our directors is set forth under "Corporate Governance Matters" in the proxy statement for our May 20, 2009 annual meeting of stockholders 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 is set forth under "Corporate Governance Matters – Committees of the Board" in the proxy statement for our May 20, 2009 annual meeting of stockholders 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 is set forth under "Section 16(a) Beneficial Ownership Reporting Compliance" in the proxy statement for our May 20, 2009 annual meeting of stockholders is incorporated herein by reference.

The information concerning our audit committee is set forth under "Corporate Governance Matters – Committees of the Board" in the proxy statement for our May 20, 2009 annual meeting of stockholders is incorporated herein by reference.

The information regarding our Code of Ethics is set forth under "Corporate Governance Matters – Corporate Governance Principles, Processes and Code of Business Conduct and Ethics" in the proxy statement for our May 20, 2009 annual meeting of stockholders is incorporated herein by reference.

ITEM 11. Executive Compensation

The information set forth under "Executive Compensation," "Corporate Governance Matters and Insider Participation" and "Certain Relationships and Related Transactions" in our proxy statement for our May 20, 2009 annual meeting of stockholders is incorporated herein by reference.

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

The information set forth under "Security Ownership of Management and Certain Beneficial Holders" in the proxy statement for our May 20, 2009 annual meeting of stockholders 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 proxy statement for our May 20, 2009 annual meeting of stockholders 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 proxy statement for our 2008 annual meeting of stockholders is incorporated herein by reference.

Information regarding our directors' independence is set forth under "Corporate Governance – Independent Directors" in the proxy statement for our May 20, 2009 annual meeting of stockholders is incorporated herein by reference.

ITEM 14. Principal Accountant Fees and Services

The information set forth under "Independent Registered Public Accountants" in the proxy statement for our May 20, 2009 annual meeting of stockholders is incorporated herein by reference.

PART IV

ITEM 15. Exhibits and Financial Statement Schedules

All schedules are omitted because the required information is inapplicable or the information is presented in the financial statements and related notes.

Exhibit No.	Sequential Description
**2.1	Contribution Agreement, dated September 11, 2007, between Quicksilver Resources Inc. and BreitBurn Operating L.P. (filed as Exhibit 10.2 to the Company's Form 8-K filed November 7, 2007 and included herein by reference.)
**2.2	Purchase and Sale Agreement, dated as of July 3, 2008, among Nortex Minerals, L.P., Petrus Investment, L.P., Petrus Development, L.P., and Perot Investment Partners, Ltd., as Sellers, and Quicksilver Resources Inc., as Purchaser (filed as Exhibit 10.1 to the Company's Form 8-K filed July 7, 2008 and included herein by reference).
**2.3	Purchase and Sale Agreement, dated as of July 3, 2008, among Hillwood Oil & Gas, L.P., Burtex Minerals, L.P., Chief Resources, LP, Hillwood Alliance Operating Company, L.P., Chief Resources Alliance Pipeline LLC, Chief Oil & Gas LLC, Berry Barnett, L.P., Collins and Young, L.L.C. and Mark Rollins, as Sellers, and Quicksilver Resources Inc., as Purchaser (filed as Exhibit 10.2 to the Company's Form 8-K filed July 7, 2008 and included herein by reference).
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 (filed as Exhibit 4.1 to the Company's Form S-3, File No. 333-151847, filed June 23, 2008 and included herein by reference).
3.2	Amended and Restated Certificate of Designation of Series A Junior Participating Preferred Stock of Quicksilver Resources Inc. (filed as Exhibit 3.3 to the Company's Form 10-Q filed May 6, 2006 and included herein by reference).
3.3	Amended and Restated Bylaws of Quicksilver Resources Inc. (filed as Exhibit 3.1 to the Company's Form 8-K filed November 16, 2007 and included herein by reference).
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) (filed as Exhibit 4.1 to the Company's Form 8-K filed November 1, 2004 and included herein by reference).
4.2	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) (filed as Exhibit 4.7 to the Company's Form S-3, File No. 333-130597, filed December 22, 2005 and included herein by reference).
4.3	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) (filed as Exhibit 4.1 to the Company's Form 8-K filed March 21, 2006 and included herein by reference).
4.4	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) (filed as Exhibit 4.1 to the Company's Form 10-Q filed November 7, 2006 and included herein by reference).
4.5	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 (filed as Exhibit 4.1 to the Company's Form 8-K filed June 530, 2008 and included herein by reference).
4.6	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 (filed as Exhibit 4.1 to the Company's Form 8-K filed July 10, 2008 and included herein by reference).

Exhibit No.	Sequential Description
4.7	Amended and Restated Rights Agreement, dated as of December 20, 2005, between Quicksilver Resources Inc. and Mellon Investor Services LLC, as Rights Agent (filed as Exhibit 4.1 to the Company's Form 8-A/A (Amendment No. 1) filed December 21, 2005 and included herein by reference).
10.1	Master Gas Purchase and Sale Agreement, dated March 1, 1999, between Quicksilver Resources Inc. and Reliant Energy Services, Inc. (filed as Exhibit 10.10 to the Company's Form S-1, File No. 333-89229, filed November 1, 2004 and included herein by reference).
10.2	Wells Agreement dated as of December 15, 1970, between Union Oil Company of California and Montana Power Company (filed as Exhibit 10.5 to the Company's Predecessor, MSR Exploration Ltd.'s Form S-4/A, File No. 333-29769, filed August 21, 1997 and included herein by reference).]
+ 10.3	Quicksilver Resources Inc. Amended and Restated 1999 Stock Option and Retention Stock Plan (filed as Exhibit 10.6 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).
+ 10.4	Form of Incentive Stock Option Agreement pursuant to the Quicksilver Resources Inc. Amended and Restated 1999 Stock Option and Retention Stock Plan (filed as Exhibit 10.2 to the Company's Form 8-K filed January 28, 2005 and included herein by reference).
+ 10.5	Form of Non-Qualified Stock Option Agreement pursuant to the Quicksilver Resources Inc. Amended and Restated 1999 Stock Option and Retention Stock Plan (filed as Exhibit 10.3 to the Company's Form 8-K filed January 28, 2005 and included herein by reference).
+ 10.6	Form of Retention Share Agreement pursuant to the Quicksilver Resources Inc. Amended and Restated 1999 Stock Option and Retention Stock Plan (filed as Exhibit 10.3 to the Company's Form 8-K filed April 19, 2005 and included herein by reference).
+ 10.7	Form of Restricted Stock Unit Agreement pursuant to the Quicksilver Resources Inc. Amended and Restated 1999 Stock Option and Retention Stock Plan (filed as Exhibit 10.4 to the Company's Form 8-K filed April 19, 2005 and included herein by reference).
+ 10.8	Quicksilver Resources Inc. Amended and Restated 2004 Non-Employee Director Equity Plan (filed as Exhibit 10.4 to the Company's Form 8-K filed May 25, 2007 and included herein by reference).
+ 10.9	Form of Non-Qualified Stock Option Agreement pursuant to the Quicksilver Resources Inc. Amended and Restated 2004 Non-Employee Director Equity Plan (filed as Exhibit 10.4 to the Company's Form 8-K filed January 28, 2005 and included herein by reference).
+ 10.10	Form of Restricted Share Agreement pursuant to the Quicksilver Resources Inc. Amended and Restated 2004 Non-Employee Director Equity Plan (filed as Exhibit 10.2 to the Company's Form 8-K filed May 18, 2005 and included herein by reference).
+ 10.11	Quicksilver Resources Inc. Second Amended and Restated 2006 Equity Plan (filed as Exhibit 10.1 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).
+ 10.12	Form of Restricted Share Agreement pursuant to the Quicksilver Resources Inc. Second Amended and Restated 2006 Equity Plan (filed as Exhibit 10.2 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.13	Form of Restricted Stock Unit Agreement pursuant to the Quicksilver Resources Inc. Second Amended and Restated 2006 Equity Plan (filed as Exhibit 10.2 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).
+ 10.14	Form of Quicksilver Resources Canada Inc. Restricted Stock Unit Agreement (Cash Settlement) pursuant to the Quicksilver Resources Inc. Second Amended and Restated 2006 Equity Plan (filed as Exhibit 10.3 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).
+ 10.15	Form of Quicksilver Resources Canada Inc. Restricted Stock Unit Agreement (Stock Settlement) pursuant to the Quicksilver Resources Inc. Second Amended and Restated 2006 Equity Plan (filed as Exhibit 10.4 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).

Exhibit No.	Sequential Description
+ 10.16	Form of Incentive Stock Option Agreement pursuant to the Quicksilver Resources Inc. Second Amended and Restated 2006 Equity Plan (filed as Exhibit 10.5 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.17	Form of Nonqualified Stock Option Agreement pursuant to the Quicksilver Resources Inc. Second Amended and Restated 2006 Equity Plan (filed as Exhibit 10.6 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.18	Form of Non-Employee Director Nonqualified Stock Option Agreement pursuant to the Quicksilver Resources Inc. Second Amended and Restated 2006 Equity Plan (One-Year Vesting) (filed as Exhibit 10.8 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.19	Form of Non-Employee Director Nonqualified Stock Option Agreement pursuant to the Quicksilver Resources Inc. Second Amended and Restated 2006 Equity Plan (Three-Year Vesting) (filed as Exhibit 10.5 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).
+ 10.20	Form of Non-Employee Director Restricted Share Agreement pursuant to the Quicksilver Resources Inc. Second Amended and Restated 2006 Equity Plan (One-Year Vesting) (filed as Exhibit 10.7 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.21	Form of Non-Employee Director Restricted Share Agreement pursuant to the Quicksilver Resources Inc. Second Amended and Restated 2006 Equity Plan (Three-Year Vesting) (filed as Exhibit 10.2 to the Company's Form 8-K filed May 25, 2007 and included herein by reference).
+ 10.22	Description of Non-Employee Director Compensation for Quicksilver Resources Inc. (filed as Exhibit 10.11 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).
+ 10.23	Quicksilver Resources Inc. 2007 Executive Bonus Plan (filed as Exhibit 10.1 to the Company's Form 8-K filed April 16, 2007 and included herein by reference).
+ 10.24	Description of 2007 Cash Bonus (filed as Exhibit 10.3 to the Company's Form 10-Q filed May 9, 2007 and included herein by reference).
+ 10.25	Quicksilver Resources Inc. 2008 Executive Bonus Plan (filed as Exhibit 10.1 to the Company's Form 8-K filed December 14, 2007 and included herein by reference).
+ 10.26	Quicksilver Resources Inc. 2009 Executive Bonus Plan (filed as Exhibit 10.10 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).
+ 10.27	Quicksilver Resources Inc. Amended and Restated Change in Control Retention Incentive Plan (filed as Exhibit 10.9 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).
+ 10.28	Quicksilver Resources Inc. Second Amended and Restated Key Employee Change in Control Retention Incentive Plan (filed as Exhibit 10.8 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).
+ 10.29	Quicksilver Resources Inc. Amended and Restated Executive Change in Control Retention Incentive Plan (filed as Exhibit 10.7 to the Company's Form 8-K filed November 24, 2008 and included herein by reference).
+ 10.30	Form of Director and Officer Indemnification Agreement (filed as Exhibit 10.1 to the Company's Form 8-K filed August 26, 2005 and included herein by reference).
10.31	Amended and Restated Credit Agreement, dated as of February 9, 2007, among Quicksilver Resources Inc. and the lenders identified therein (filed as Exhibit 10.1 to the Company's Form 8-K filed February 12, 2007 and included herein by reference).
10.32	Amended and Restated Credit Agreement, dated as of February 9, 2007, among Quicksilver Resources Canada Inc. and the lenders and/or agents identified therein (filed as Exhibit 10.2 to the Company's Form 8-K filed February 12, 2007 and included herein by reference).

Exhibit No.	Sequential Description
10.33	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 (filed as Exhibit 10.1 to the Company's Form 8-K filed June 25, 2008 and included herein by reference).
10.34	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 (filed as Exhibit 10.1 to the Company's Form 8-K filed August 5, 2008 and included herein by reference).
10.35	Credit Agreement, dated as of August 8, 2008, among Quicksilver Resources Inc., the lenders party thereto and Credit Suisse, Cayman Islands Branch, as administrative agent (filed as Exhibit 10.1 to the Company's Form 8-K filed August 8, 2008 and included herein by reference).
10.36	Registration Rights Agreement, dated as of November 1, 2007, between Quicksilver Resources Inc. and BreitBurn Energy L.P. (filed as Exhibit 10.1 to the Company's Form 8-K filed November 7, 2007 and included herein by reference).
+10.37	2007 Equity Plan (filed as Exhibit 99.1 to Quicksilver Gas Services LP's Form S-8, File No. 333-145326, filed August 10, 2007 and included herein by reference).
+10.38	Form of Phantom Unit Award Agreement for Non-Directors (Cash) (filed as Exhibit 10.10 to Quicksilver Gas Services LP's Form S-1/A, File No. 333-140599, filed July 17, 2007 and included herein by reference).
+10.39	Form of Phantom Unit Award Agreement for Non-Directors (Units) (filed as Exhibit 10.11 to Quicksilver Gas Services LP's Form S-1/A, File No. 333-140599, filed July 25, 2007 and included herein by reference).
+10.40	Quicksilver Gas Services LP Annual Bonus Plan (filed as Exhibit 10.1 to Quicksilver Gas Services LP's Form 8-K, File No. 001-33631, filed December 13, 2007 and included herein by reference).
+10.41	Form of Indemnification Agreement by and between Quicksilver Gas Services GP LLC and its officers and directors (filed as Exhibit 10.7 to Quicksilver Gas Services LP's Form S-1/A, File No. 333-140599, filed July 17, 2007 and included herein by reference).
* 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.
* 24.1	Power of Attorney
* 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.

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* Filed herewith.

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

\+ Identifies management contracts and compensatory plans or arrangements.

SIGNATURES

Pursuant to the requirements of Section 13 of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Quicksilver Resources Inc.
(the "Registrant")

By: /s/ Glenn Darden
Glenn Darden
President and Chief Executive Officer

Dated: March 2, 2009

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
* Thomas F. Darden	Chairman of the Board; Director	March 2, 2009
/s/ Glenn Darden Glenn Darden	President and Chief Executive Officer (Principal Executive Officer); Director	March 2, 2009
* Philip Cook	Senior Vice President – Chief Financial Officer (Principal Financial Officer)	March 2, 2009
* John C. Regan	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)	March 2, 2009
* Anne Darden Self	Director	March 2, 2009
* W. Byron Dunn	Director	March 2, 2009
* Steven M. Morris	Director	March 2, 2009
* W. Yandell Rogers, III	Director	March 2, 2009
* Mark J. Warner	Director	March 2, 2009

* The undersigned, by singing his name hereto, does sign and execute this Annual Report on Form 10-K pursuant to the Powers of Attorney executed by the above-named officers and directors and filed herewith.

By: /s/ Glenn Darden
Glenn Darden
Attorney-in-Fact

QUICKSILVER RESOURCES INC.
2008 Finding and Development Costs and
2008 Finding, Development and Acquisition Costs
(Unaudited)

The following schedule reflects a reconciliation of 2008 "Finding and Development Costs" (F&D) and 2008 "Finding, Development and Acquisition Costs" (FD&A) to the information required by paragraphs 11 and 21 of Statement of Financial Accounting Standard No. 69. F&D Costs are computed by dividing exploration and development capital expenditures for the year, plus SFAS 143 asset retirement obligation additions for the year and unevaluated capital expenditures as of beginning of the year, less unevaluated capital expenditures as of end of the year, by reserve additions for the year, excluding acquired reserves. FD&A Costs are computed by dividing exploration, development and acquisition capital expenditures for the year, plus SFAS 143 asset retirement obligation additions for the year and unevaluated capital expenditures as of beginning of the year, less unevaluated capital expenditures as of end of the year, by total reserve additions for the year.

2008 F&D Costs

Dollars in millions, reserves in billions of cubic feet equivalent	
Total exploration and development capital expenditures	$1,047.9
SFAS 143 asset retirement obligation additions	4.6
Adjustments:	
Unevaluated costs as of December 31, 2007	215.2
Unevaluated costs as of December 31, 2008	(291.9) (1)
Adjusted capital expenditures related to reserve additions	$ 975.8
Reserve extensions, discoveries and revisions (Bcfe)	454.8
Finding & development costs ($/mcfe)	$ 2.14

(1) Assumes that $62.4 million of costs related to West Texas were not moved out of unevaluated costs in 2008

2008 FD&A Costs

Dollars in millions, reserves in billions of cubic feet equivalent	
Total exploration, development and acquisition capital expenditures	$2,271.1
SFAS 143 asset retirement obligation additions	5.7
Adjustments:	
Unevaluated costs as of December 31, 2007	215.2
Unevaluated costs as of December 31, 2008	(605.9)(1)
Adjusted capital expenditures related to reserve additions	$1,886.1
Reserve extensions, discoveries, revisions and purchases (Bcfe)	754.7
Finding, development and acquisition costs ($/mcfe)	$ 2.50

(1) Assumes that $62.4 million of costs related to West Texas were not moved out of unevaluated costs in 2008

Management believes that providing a measure of F&D and FD&A costs is useful to assist an evaluation of how much it cost Quicksilver, on a per thousand cubic feet of natural gas equivalent basis, to add proved reserves. However, the reader is cautioned that these measures are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in Quicksilver's financial statements prepared in accordance with GAAP (including the notes thereto). The reader is further cautioned that, due to various factors, including timing differences, F&D and FD&A costs do not necessarily reflect precisely the costs associated with particular reserves. For example, exploration costs may be recorded in periods prior to the periods in which related increases in reserves are recorded and development costs may be recorded in periods subsequent to the periods in which related increases in reserves are recorded. In addition, changes in commodity prices can affect the magnitude of recorded increases in reserves independent of the related costs of such increases.

As a result of the foregoing factors and various factors that could materially affect the timing and amounts of future increases in reserves and the timing and amounts of future costs, including factors disclosed in Quicksilver's filings with the Securities and Exchange Commission, we cannot assure you that Quicksilver's future finding costs will not differ materially from those set forth above.

The methods used by Quicksilver to calculate its finding costs may differ significantly from methods used by other companies to compute similar measures. As a result, Quicksilver's finding costs may not be comparable to similar measures provided by other companies.

QUICKSILVER RESOURCES INC.
Calculation of 2008 Production Replacement Ratio

The production replacement ratio is calculated by dividing the sum of reserve additions from revisions, extensions and discoveries for a period by the actual production for the period. Additions to our reserves are proved developed and proved undeveloped reserves. We expect to continue to add to our total proved reserves through these activities, but various factors could impede our ability to do so, including factors disclosed in Quicksilver's filings with the Securities and Exchange Commission. We use the production replacement ratio as an indicator of our ability to replenish annual production volumes and grow reserves. We believe that production replacement is relevant and useful information that is commonly used by parties interested in the oil and gas industry as a means of evaluating the operational performance and prospects of entities engaged in the production and sale of depleting natural resources. However, the reader is cautioned that the production replacement ratio is a statistical indicator that has limitations. As an annual measure, the ratio is limited because it typically varies widely based on the extent and timing of new discoveries and may increase or decrease due to increases or decreases in the prices of the related commodities. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not consider the cost or timing of future production of new reserves, it cannot be used as a measure of value creation. Moreover, the ratio does not distinguish between changes in reserve quantities that are developed and those that will require additional time and funding to develop.

Million cubic feet of natural gas equivalents	
Reserve additions	
Revisions	(320,298)
Extensions & discoveries	775,108
Total additions	454,810
Production	96,202
Production replacement	473%

CORPORATE INFORMATION

DIRECTORS

Thomas F. Darden
Chairman
Glenn Darden
W. Byron Dunn*
James A. Hughes*
Steven M. Morris*
W. Yandell Rogers III*
Anne D. Self
Mark J. Warner*

OFFICERS

Thomas F. Darden
Chairman
Glenn Darden
President & Chief Executive Officer
Jeff Cook
Executive Vice President – Operations
Philip W. Cook
Senior Vice President – Chief Financial Officer
John C. Cirone
Senior Vice President, General Counsel & Secretary
C. Clay Blum
Vice President – Land
Richard C. Buterbaugh
Vice President – Investor Relations & Corporate Planning
MarLu S. Hiller
Vice President – Treasurer
Stan G. Page
Vice President – U.S. Operations
John C. Regan
Vice President, Controller & Chief Accounting Officer
Anne D. Self
Vice President – Human Resources
Robert N. Wagner
Vice President – Reservoir Engineering

As of March 1, 2009

HEADQUARTERS

777 W. Rosedale St.
Fort Worth, Texas 76104
Phone: 817.665.5000
Fax: 817.665.5004
quicksilver@qrinc.com
www.qrinc.com

MAJOR SUBSIDIARIES

Quicksilver Gas Services LP
777 W. Rosedale St.
Fort Worth, Texas 76104
Phone: 817.665.8620
Fax: 817.665.5008
www.kgslp.com

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

REGISTRAR AND TRANSFER AGENT

BNY Mellon Shareowner Services
480 Washington Blvd.
Jersey City, New Jersey 07310
Phone: 866-637-5420
www.bnymellon.com/shareowner/isd

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 am, May 20, 2009 at the Petroleum Club, 777 Main Street Fort Worth, Texas.

* Member of the Audit; Compensation; Health, Safety and Environmental; and Nominating and Corporate Governance Committees

QUICKSILVER
RESOURCES

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