CONSISTENT

REPEATABLE

ORGANIC GROWTH

COMPANY PROFILE

Quicksilver Resources Inc. is an independent exploration and production company focused on identifying 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, 2007, the company had estimated proved reserves of approximately 1.55 trillion cubic feet of natural gas equivalents, of which 99 percent were natural gas or natural gas liquids and 62 percent were proved developed.

The company also owns approximately 73 percent of Quicksilver Gas Services LP, a midstream limited partnership and approximately 32 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

LOW-RISK, RELIABLE, REPEATABLE ORGANIC GROWTH.

You saw this last year and in the years before that. What has changed is the rate of growth. In Quicksilver's eighth year as a public company, after more than a 30-fold increase in the company's stock price from inception, the production growth rate is increasing!

Last year at this time, we predicted that 2007 would be the best growth year in Quicksilver's history – and it was. What we did not predict was the divestment in November 2007 of the company's Michigan, Indiana, and Kentucky properties, representing more than one-third of our production and reserves. This accretive transaction put the spotlight on the significant organic growth of our remaining properties and greatly de-levered the company's balance sheet.

Even after divesting these properties, the company replaced the sold reserves by year end with new reserves from drilling activities representing nearly 780% production replacement at an industry-leading finding and development cost of just $1.37 per thousand cubic feet of gas equivalent. We expect that by mid-year 2008, the divested production volumes will be replaced as well.

Quicksilver also launched a subsidiary company in the public markets, Quicksilver Gas Services LP (KGS), a midstream limited partnership which owns and operates gathering and processing assets in the Fort Worth Basin Barnett Shale play. By taking KGS public, Quicksilver received more than $100,000,000 in cash which further strengthened the company's financial position, and we retained 72% of the limited partner units and 100% of the general partner interest in this fast growing entity. KGS complements Quicksilver's stellar acreage position in the Fort Worth Basin Barnett Shale play, where we achieved 160% production growth in 2007 and we expect many years of organic growth ahead of us.

Quicksilver's lease position in the Fort Worth Basin is located in a particularly rich hydrocarbon window that results in income from both natural gas and natural gas liquids. In fact, these liquids, where value correlates more closely with the price of oil, are generating more than 40% of the revenue from our Barnett project. We are concentrating approximately 85% of our 2008 capital budget in this high-growth basin and expect production to more than double again this year.

Quicksilver Resources Canada Inc., our Canadian subsidiary, once again delivered double-digit production growth in 2007. The team is doing an excellent job of harvesting the Horseshoe Canyon coalbed methane project in Alberta and is actively developing new opportunities in this basin and other unconventional plays throughout Canada.

But we don't concentrate on growth merely for growth's sake. A major goal in the Quicksilver organization is cost control. In addition to adding proved developed reserves at one of the lowest finding and development cost in the industry, we continue to work hard to keep our unit production costs low as well. This emphasis on hammering costs must be cultural and we work on it every day. Our goal is to be the lowest cost and highest growth company.

To achieve this, we will continue to spend up to 10% of our annual capital budget on the hunt for new resources in additional onshore basins in North America. We are continuing the testing of Barnett and Woodford shales in the Delaware Basin in West Texas and are pursuing new basins to capitalize on our expertise in the development of unconventional gas reservoirs. Our company is well-positioned to take advantage of the improving technology in this segment of the industry.

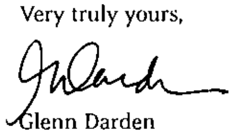
Quicksilver is in the strongest position in its history to capitalize on these new opportunities. The balance sheet is solid and the company has used the recent rally in natural gas prices to lock in hedges at attractive levels for a majority of our production for the next two years.

The company has a multi-year inventory of development locations to drill on high-return projects which could quadruple our existing reserves. With some luck in some of our new areas we can do much better than that.

We have a talented, hard-working group of co-workers and a very seasoned and circumspect board of directors and we thank them for their continued dedication. All of these ingredients contribute to achieving our number one goal of increasing the value of our stockholders' investment.

We thank all of the Quicksilver stockholders for their continued support and are confident that 2008 will be another outstanding year for the company.

Very truly yours,



Glenn Darden
President and CEO

Thomas F. Darden
Chairman

FINANCIAL HIGHLIGHTS

In thousands, except per share, production and product price data	2007	2006 [a]	2005 [a]	2004 [a]	2003 [a]
Total revenues	$ 561,258	$ 390,362	$ 310,448	$ 179,729	$ 140,949
Income before income taxes and minority interest	$ 736,941	$ 131,960	$ 127,974	$ 45,446	$ 28,502
Net income [b]	$ 479,378	$ 93,719	$ 87,434	$ 31,272	$ 16,208
Net income per diluted share [b]	$ 2.86	$ 0.58	$ 0.54	$ 0.21	$ 0.12
Diluted weighted average number of shares outstanding for the periods	168,029	166,266	164,912	154,030	137,068
Total assets	$ 2,775,846	$ 1,882,912	$ 1,243,094	$ 888,334	$ 666,934
Long-term debt	$ 813,817	$ 919,117	$ 506,039	$ 399,134	$ 249,097
Total stockholders' equity	$ 1,068,355	$ 575,666	$ 383,615	$ 304,276	$ 241,816
Natural gas production (Mmcf)	59,619	53,266	46,769	39,351	34,536
Average realized natural gas price per Mcf [c]	$ 6.73	$ 6.05	$ 5.76	$ 3.83	$ 3.38
NGL production (Mmcfe)	14,826	4,476	1,338	774	810
Average realized NGL price per Mcfe [c]	$ 7.21	$ 6.48	$ 6.51	$ 4.75	$ 3.58
Crude oil production (Mbbl)	$ 584	587	553	689	808
Average realized price per Bbl [c]	$ 63.87	$ 59.99	$ 50.50	$ 33.07	$ 24.23

[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 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 2007, 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's management, the matters addressed therein 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's financial condition, results of operations and cash flows 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; competitive conditions in our industry; actions taken by third-parties, including operators, processors and transporters; 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's 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 Cost and Production Replacement Ratio that follow the signature page of 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, 2007

SEC Mail Processing Section

OR

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

APR 10 2008

For the transition period from to

Washington, DC 110

Commission file number: 001-14837

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

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

817-665-5000
(Registrant's telephone number, including area code)
(Former name, former address and former fiscal year, if changed since last report)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $0.01 par value per share	New York Stock Exchange
Preferred Share Purchase Rights, $0.01 par value per share	New York Stock Exchange

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

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

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

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

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

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller Reporting company ☐

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

As of June 29, 2007, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $2,254,444,615 based on the closing sale price of $22.29 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 January 31, 2008
Common Stock, $0.01 par value per share	158,496,046 shares

DOCUMENTS INCORPORATED BY REFERENCE

Document	Parts Into Which Incorporated
Proxy Statement for the Registrant's May 21, 2008 Annual Meeting of Stockholders	Part III

INDEX TO ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2007

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.

Share and per share amounts have been adjusted to reflect a two-for-one stock split effected in the form of a stock dividend in June 2004, 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.

DEFINITIONS

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

"AECO" means the price of gas delivered onto the NOVA Gas Transmission Ltd. System

"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, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas

"Btu" means British Thermal units, a measure of heating value

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

"CBM" means coalbed methane

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

"Inside FERC" refers to the publication *Inside F.E.R.C.'s Gas Market Report*

"LIBOR" means London Interbank Offered Rate

"MBbls" means thousand barrels

"MMBbls" means million barrels

"MMBtu" means million Btu and is approximately equal to 1 Mcf

"MMBtud" means million Btu per day

"Mcf" means thousand cubic feet

"MMcf" means million cubic feet

"MMcfd" means million cubic feet per day

"MMcfe" means million cubic feet of natural gas equivalents, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas

"NGL" or "NGLs" means natural gas liquids

"NYMEX" means New York Mercantile Exchange

"Oil" includes crude oil and condensate

"SEC" means United States Securities and Exchange Commission

"Tcf" means trillion cubic feet

"Tcfe" means trillion cubic feet of natural gas equivalents, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas

COMMONLY USED TERMS

Other commonly used terms and abbreviations include:

"BBEP" means BreitBurn Energy partners L.P. to whom we conveyed our Northeast Operations on November 1, 2007

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

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

"KGS" means Quicksilver Gas Services LP which is our publicly-traded midstream operations which trade under the ticker symbol "KGS"

"IPO" means initial public offering and relates to KGS who completed their initial public offering on August 10, 2007

"FASB" means the Financial Accounting Standards Board who promulgate accounting standards

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

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

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 natural gas and oil properties in the United States, principally in Texas, Wyoming and Montana and in Canada, principally in Alberta, which in total had estimated proved reserves of approximately 1.5 Tcfe of natural gas at December 31, 2007. We previously held properties in Michigan, Indiana and Kentucky ("Northeast Operations") which were divested on November 1, 2007. In addition to our natural gas and oil operations, we own approximately 73% of Quicksilver Gas Services LP ("KGS"), a publicly traded midstream master limited partnership controlled by us, and we own approximately 32% of the limited partner units of BreitBurn Energy Partners L.P. ("BBEP" or "BreitBurn"), a publicly-traded natural gas and oil exploration and production master limited partnership.

Our common stock began trading publicly in 1999 and currently 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 (telephone 817-665-5000). 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 through a merger with MSR Exploration Ltd. ("MSR"). As of December 31, 2007, members of the Darden family, together with Quicksilver Energy, L.P., an entity controlled by members of the Darden family, beneficially owned approximately 34% of our outstanding common stock. Thomas Darden, Glenn Darden and Anne Darden Self serve on our Board of Directors along with five independent directors. Thomas Darden is Chairman of our Board, Glenn Darden is our President and Chief Executive Officer and Anne Darden Self is our Vice President – Human Resources.

STRATEGIC REALIGNMENT

During 2007, we made a number of strategic decisions in an effort to highlight the value of some of our under-appreciated assets and the high-growth nature of Quicksilver's underlying property base. These decisions resulted in two major transactions for the Company. We contributed our midstream operations in the Fort Worth Basin to KGS and completed an initial public offering ("IPO") of approximately 27% of KGS' limited partnership interests in August. KGS operations continue to be consolidated within our financial statements following the IPO. In November, we completed the divestiture of all of our property interests in our Northeast Operations to BBEP in exchange for $750 million in cash and approximately 21.348 million units in BBEP (the "BreitBurn Transaction"). We used proceeds from the initial public offering and the Northeast Operations divestment to repay debt and substantially strengthen our financial structure. The combined cash flows from the interest savings associated with the debt repayment and the anticipated distributions on the BBEP units are expected to offset more than 70% of the cash flow previously generated by our Northeast Operations.

BUSINESS STRATEGY

We have a multi-pronged strategy to increase share value through organic, 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 annual capital budget on low-risk development and exploitation projects on our extensive leasehold positions in the Fort Worth and Western Canadian Sedimentary basins. In 2008, we expect to drill approximately 200 net development wells in our Barnett Shale properties in the Fort Worth Basin of North Texas and approximately 165 net development wells in our Canadian coalbed methane properties in Alberta, Canada. We believe that operating in concentrated areas allows us to more efficiently deploy our resources and manage costs. In addition, we can further leverage our base of technical expertise in these regions.

Pursue disciplined organic growth opportunities: We will invest a disciplined amount of capital annually 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 2008, we plan to continue to explore on our acreage in the Delaware Basin of West Texas by drilling additional resource assessment wells along with further evaluation of the five existing wells, that we drilled or re-entered previously in this area, to better define the potential for commercial viability of this region. In addition, we will 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 natural gas, NGLs and crude oil from the areas where we have production to distribution pipelines owned by third parties. We seek to achieve this by continuing to improve upon and add to our processing and distribution 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 continue to control our midstream operations in the Fort Worth Basin through our approximate 73% interest in KGS including owning 100% of its general partner. We also monitor on a daily basis the spot markets for commodities and seek to sell our uncommitted production into the most attractive markets.

Maintain flexible financial profile: We believe that maintaining a conservative financial structure will better position us to capitalize on opportunities to limit our financial risk. We have also established minimum expected return thresholds for new projects. We believe our ownership interest in KGS and BBEP provides additional financial flexibility for the Company while enabling us to participate in the expected future growth of both of 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 have entered into advance natural gas physical sales contracts with price floors and natural gas and financial hedges covering a portion of our production.

BUSINESS STRENGTHS

High-quality asset base with long reserve life: We had total proved reserves of approximately 1.5 Tcfe as of December 31, 2007, of which approximately 99% was natural gas and NGLs and approximately 62% was proved developed. The majority of these reserves are located in two core areas: the Fort Worth Basin in North Texas and the Western Canadian Sedimentary Basin in Alberta, Canada, which accounted for approximately 78% and 21%, respectively, of our proved reserves. Based on 2007 average production from these properties, our implied reserve life (proved reserves divided by 2007 annual production net of production from the divested Northeast Operations) was 28.2 years and our implied proved developed reserve life was 17.5 years. We believe our assets are characterized by long reserve lives and predictable well production profiles. As of December 31, 2007, we were the operator of properties containing approximately 98% of our proved reserves.

Multi-year inventory of development and exploitation drilling projects: As of December 31, 2007, we owned leases covering more than 462,000 net acres in our core areas of the Fort Worth and the Western Canadian Sedimentary basins, of which approximately 79% were undeveloped. This drilling inventory is expected to provide us with more than 3,000 identified drilling locations which we expect to exploit during the next eight to ten years. Our drilling success rate has averaged 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. For 2008, we have budgeted approximately $650 million for drilling projects.

Proven record of organic growth in reserves and production: During the past three years, we have added approximately 1,310 Bcfe to our reserves, virtually all of which was achieved organically and divested approximately 546 Bcfe associated with our former Northeast Operations. This growth was the result of our ability to acquire attractive undeveloped acreage and apply our technical expertise to find and develop reserves and was accompanied by a significant increase in our overall production. In recent years, we have demonstrated this ability particularly in the Barnett Shale formation in the Fort Worth Basin and in coal bed methane formations in Alberta. We believe our current acreage position will enable us to continue our reserve and production growth.

Midstream Strength: Our midstream operations are well positioned to complement the primary business objective and business strategies of our exploration and production initiatives and to compete with other midstream providers for unaffiliated business. Quicksilver's operational structure allows our midstream operations to more accurately forecast future throughput volumes and the need and timing for capacity additions. It also allows our midstream operations to coordinate their capacity additions with our production growth and associated gathering and processing needs. Since our midstream assets are concentrated within the high-growth Fort Worth Basin, we believe that our midstream operations are positioned to expand the gathering system footprint, increase throughput volumes and plant utilization, ultimately increasing 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 we were formed in 1997. They both have been in the natural gas and oil 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 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 pipeline systems. The vast majority of our midstream operations in the Fort Worth Basin are conducted by KGS of which we control and own over 70% of the partnership interests, including 100% of its general partner. We also indirectly own interests in other natural gas and oil properties through our ownership of approximately 21.348 million limited partnership units in BBEP, which constitute approximately 32% of the partnership interests in BBEP.

NATURAL GAS AND OIL INTERESTS

Our natural gas and oil operations are focused primarily in unconventional natural gas plays, onshore in North America. Our current production and development operations are concentrated in the Fort Worth and Western Canadian Sedimentary basins. At December 31, 2007, we had estimated total proved reserves of approximately 1.5 Tcfe, approximately 99% of which were natural gas and NGLs and approximately 62% of which were proved developed. Approximately 78% of our reserves at December 31, 2007 were located in Texas and approximately 21% were in Canada. For the year ended December 31, 2007, we had average production of 213 MMcfe per day and total production of 77.9 Bcfe. Since going public in 1999, we have grown our reserves and production at an approximate compound annual growth rate of 23% and 18% respectively, despite the divestiture of our Northeast Operations as of November 1, 2007, which included approximately 546 Bcfe of reserves at the time of the divestiture and accounted for approximately 62.9 MMcfe per day of our reported production in 2007.

Texas

Our development operations are focused on the Barnett Shale play in the Fort Worth Basin in North Texas, which comprised nearly 100% of our estimated proved reserves in Texas and approximately 42% of our total average daily production for the year ended December 31, 2007. At December 31, 2007, our net production from wells in the Fort Worth Basin was approximately 130 MMcfe per day. With the divestiture of our Northeast Operations, we expect our 2008 production from Texas to represent approximately 75% of total projected volumes for the year.

Our acreage interests in the Fort Worth Basin are spread across an area 40 miles by 30 miles centered in Hood County. At December 31, 2007, we held approximately 247,000 net acres in the Fort Worth Basin Barnett Shale play with more than 1,600 remaining estimated drilling locations. Approximately 20% of this acreage is currently developed. Much of our acreage in this play 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 a midstream system that we constructed and which is now owned and operated by KGS. This system includes processing facilities which have the capacity to process more than 200 MMcfd of natural gas. KGS has begun construction of a third processing unit, with an additional 125 MMcfd of capacity that we expect to become operational in the first quarter of 2009.

The KGS pipeline and gathering system is located in the southern portion of the Fort Worth Basin, which includes over 200 miles of natural gas gathering pipelines, ranging from 2 inches to 20 inches in diameter and a 25-mile NGL pipeline that runs from the processing plant to an interconnecting pipeline owned by a third party. 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 pipelines, which do not meet current threshold returns for KGS, to gather and deliver natural gas to the processing facilities as additional wells in the Fort Worth Basin are drilled and completed. Our capital expenditures budget for 2008 includes approximately $160 million for midstream assets, including $80 million to be spent by KGS.

During 2007, we drilled 244 gross (219 net) wells in the Fort Worth Basin Barnett Shale primarily from multi-well drilling pads. On these multi-well pads, all the wells are drilled prior to initiating completion activities. At December 31, 2007, we had drilled a total of 426 gross (377 net) wells in the Fort Worth Basin since we began exploration and development operations in 2003. In 2007 we completed 201 gross (184 net) wells and tied 187 gross (163 net) wells into sales. Most of the wells not tied into sales as of December 31, 2007 are expected to be producing and tied into sales during 2008.

During 2005, we acquired approximately 310,000 net acres in a contiguous block in the Delaware Basin of West Texas and we currently have approximately 470,000 net acres in the area. At December 31, 2007, we had drilled five resource assessment wells on that acreage to evaluate horizontal and vertical opportunities within both the Barnett and Woodford shales. We expect to drill approximately six additional wells in the area in 2008 and are continuing to evaluate these resource assessment wells. We hope to complete this evaluation during 2008.

The 2008 capital budget allocated to drilling operations for our Texas interests is approximately $582 million. We anticipate that this will fund approximately 200 net wells in the Fort Worth Basin and additional resource assessment wells in the Delaware Basin. We expect that substantially all the wells we plan to drill in 2008 will be horizontal wells. At December 31, 2007, we had 12 drilling rigs operating for us in the Fort Worth Basin, and we expect to average at approximately this level throughout 2008.

Rocky Mountain Region

Our Rocky Mountain properties are located in Montana and Wyoming. Production from those properties is primarily crude oil from well-established producing formations at depths ranging from 1,000 feet to 17,000 feet. At December 31, 2007, our Rocky Mountain proved reserves were approximately 2.5 MMBbls of crude oil and 1.8 Bcfe of natural gas and NGLs for total equivalent reserves of 17 Bcfe. Daily production from our properties in the Rocky Mountain region averaged 3.1 MMcfe per day for 2007.

Canada

We conduct our Canadian operations through our wholly-owned subsidiary, Quicksilver Resources Canada Inc. At December 31, 2007, Canadian reserves of 328 Bcfe comprised 21% of our total reserves, primarily attributable to our CBM projects. Daily production averaged 56.9 MMcfe representing approximately 27% of our total 2007 production. Canadian capital expenditures for 2007 were primarily funded by Canadian cash flows from operations.

Since 2003, we have expanded our operations in the Western Canadian Sedimentary Basin. Net sales from our projects in Alberta averaged 60.5 MMcfe per day during the fourth quarter of 2007. During 2007, we drilled 355 gross (184 net) productive wells with 359 gross (185 net) wells tied into sales. During 2008, we plan to drill approximately 300 gross (170 net) wells. As of December 31, 2007, we had approximately 311,000 gross (226,000 net) undeveloped acres in Canada.

Other Properties

We believe that much of our future growth will be through development, exploitation and exploration of our leasehold interests, principally those in the Barnett Shale formation in the Fort Worth Basin in North Texas and coalbed methane formations in Alberta, Canada. In addition, we are actively exploring the Barnett Shale and Woodford Shale formations in 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 are also pursuing acquisition of additional undeveloped leasehold interests, which has the potential to capitalize on our proven expertise in unconventional gas plays.

2008 Capital Program

We intend to focus our capital spending program primarily on the continued development, exploitation and exploration of our properties in Texas and Alberta, Canada. For 2008, we have established a capital budget of $885 million, of which we have allocated $650 million for drilling activities, $160 million for gathering and processing facilities, including approximately $80 million associated with KGS, $70 million for acquisition of additional leasehold interests and $5 million for other property and equipment. On a regional basis, approximately $565 million has been allocated to the Fort Worth Basin for drilling approximately 200 net wells. Canada has been allocated $56 million for drilling and is expected to increase production by approximately 8% in 2008 when compared to 2007 production. The remaining drilling capital budget is spread among our other operating areas. The budget for gathering and processing expenditures includes $140 million in Texas, which includes $80 million of expenditures to be funded by KGS, and $15 million in Canada.

NATURAL GAS AND OIL RESERVES

The following reserve quantity and future net cash flow information concerns our proved reserves that are located in the United States and Canada. 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 natural gas and oil reserves, as defined by SEC Regulation S-X Rule 4-10, are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (i.e., prices and costs as of the date the estimate is made). 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 natural gas and oil reserves are reserves that are expected to be recovered through existing wells with existing equipment and operating methods. Additional natural gas and oil expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped natural gas and oil 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 natural gas and oil reserves is based on estimates that are highly complex and interpretive. Reserve engineering is a subjective process that is dependent on 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, 2007, 2006 and 2005.

	Total Proved Reserves For the Years Ended December 31,			Proved Developed Reserves For the Years Ended December 31,		
	2007	2006	2005	2007	2006	2005
Natural gas (MMcf)						
United States	662,409	933,342	716,043	379,917	626,582	593,630
Canada	328,381	308,335	304,910	260,029	217,759	199,859
Total	990,790	1,241,677	1,020,953	639,946	844,341	793,489
NGL (MBbl)						
United States	90,055	47,985	9,623	50,738	18,771	5,153
Canada	10	16	—	10	16	—
Total	90,065	48,001	9,623	50,748	18,787	5,153
Crude oil (MBbl)						
United States	3,074	6,315	5,915	2,763	5,236	4,986
Canada	—	—	—	—	—	—
Total	3,074	6,315	5,915	2,763	5,236	4,986
Total (MMcfe)	1,549,624	1,567,573	1,114,181	961,012	988,477	854,326

	Years Ended December 31,		
	2007	2006	2005
Representative natural gas and crude oil prices:[1]			
Natural gas — Henry Hub Spot	$ 6.80	$ 5.64	$ 10.08
Natural gas — AECO	6.35	5.39	8.41
Crude oil — WTI Cushing	95.98	60.85	61.06
Standardized measure of discounted future net cash flows[2], after income tax (in millions)	$2,169.2	$1,485.8	$1,824.1

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

(2) 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 or participated in the drilling of the following exploratory and development wells:

	Years Ended December 31,					
	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Development:						
United States						
Productive	78.0	66.4	41.0	32.8	43.0	28.4
Non-productive	—	—	—	—	—	—
Canada						
Productive	241.0	120.4	162.0	86.6	243.0	134.7
Non-productive	—	—	—	—	—	—
Total	319.0	186.8	203.0	119.4	286.0	163.1
Exploratory:						
United States						
Productive	214.0	181.0	160.0	126.4	97.0	66.7
Non-productive	2.0	1.3	8.0	8.0	5.0	5.0
Canada						
Productive	114.0	63.6	238.0	128.6	240.0	124.4
Non-productive	1.0	0.1	—	—	—	—
Total	331.0	246.0	406.0	263.0	342.0	196.1
Total:						
Productive	647.0	431.4	601.0	374.4	623.0	354.2
Non-productive	3.0	1.4	8.0	8.0	5.0	5.0
Total	650.0	432.8	609.0	382.4	628.0	359.2

ACQUISITION, EXPLORATION AND DEVELOPMENT CAPITAL EXPENDITURES

	United States	Canada (In thousands)	Consolidated
2007			
Proved acreage	$ —	$ —	$ —
Unproved acreage	17,031	31,448	48,479
Development costs	213,180	53,439	266,619
Exploration costs	511,314	26,122	537,436
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
2005			
Proved acreage	$ 821	$ 1,620	$ 2,441
Unproved acreage	48,419	3,784	52,203
Development costs	24,007	82,388	106,395
Exploration costs	109,148	9,829	118,977
Total	$182,395	$ 97,621	$280,016

PRODUCTIVE OIL AND GAS WELLS

The following table summarizes productive oil and gas wells attributable to our direct interests as of December 31, 2007:

	As of December 31, 2007			
	Productive Wells			
	Natural Gas		Crude Oil	
	Gross	Net	Gross	Net
United States	320.0	276.2	224.0	220.3
Canada	2,276.0	1,105.0	2.0	0.1
Total	2,596.0	1,381.2	226.0	220.4

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. The following table indicates our interest in developed and undeveloped acreage held directly by us. Developed acres are defined as acreage spaced or 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 quantities of crude oil, condensate or natural gas, 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.

	As of December 31, 2007			
	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Texas	64,352	53,881	787,248	666,544
Other	92,599	82,075	141,190	121,078
United States	156,951	135,956	928,438	787,622
Canada	362,210	224,102	310,665	226,017
Total	519,161	360,058	1,239,103	1,013,639

The following table lists the total number of net undeveloped acres as of December 31, 2007, and with respect to those acres for 2008, 2009 and 2010, the number of net acres expiring, and, where applicable, the number of net acres expiring that are subject to options to extend. The option to extend varies from lease to lease and covers periods from one to five years; however, the majority of the options to extend are for two years.

		2008 Expirations		2009 Expirations		2010 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	666,544	128,023	35,954	86,843	17,795	379,422	23,292
Other U.S.	121,078	4,590	—	10,290	—	5,362	—
Canada	226,017	99,919	—	32,811	—	31,685	—
Totals	1,013,639	232,532	35,954	129,944	17,795	416,469	23,292

All of the acreage scheduled to expire can be held through drilling operations. We believe that we have the ability to hold all of the expiring acreage that we feel is prospective of economic production through the drilling of wells and, where applicable, through the exercise of extension options to be followed by drilling prior to final expiration.

MARKETING

We sell natural gas, NGLs and crude oil to a variety of customers, including utilities, major natural gas and oil 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 a single purchaser in the areas in which we sell our products would not materially affect our sales. During 2007, Dynegy, the largest purchaser of our products, accounted for approximately 13% of our total natural gas, NGL and crude oil sales.

COMPETITION

We encounter substantial competition in acquiring natural gas and oil leases and properties, marketing natural gas and crude oil, securing personnel and conducting our drilling and field operations. Our competitors in development, exploitation, exploration, acquisition and production include the major natural gas and oil companies as well as numerous independents and individual proprietors. See "Item 1A. Risk Factors."

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. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted so we are unable to predict the future cost or impact of complying with such laws and regulations.

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 natural gas and oil 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 natural gas and oil industry is currently subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain natural gas and oil industry operations. In addition, legislation requires that well and facility sites be constructed, abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in substantial cash expenses, including possible fines and penalties.

In Alberta, environmental compliance has been governed by the Alberta Environmental Protection and Enhancement Act ("AEPEA") since September 1, 1993. AEPEA imposes environmental responsibilities on natural gas and oil operators in Alberta and also imposes penalties for violations.

AVAILABILITY OF REPORTS AND CORPORATE GOVERNANCE DOCUMENTS

We make available free of charge on our internet website, www.qrinc.com, our annual report 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 31, 2008, we had 496 full-time employees and 9 part-time employees. We are not a party to any collective bargaining agreements.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following information is provided with respect to our executive officers (indicated by asterisk) and certain other officers as of February 15, 2008.

Name	Age	Position(s)
Thomas F. Darden*	54	Director, Chairman of the Board
Glenn Darden*	52	Director, President and Chief Executive Officer
Anne Darden Self*	50	Director, Vice President – Human Resources
P. Jeff Cook*	51	Executive Vice President – Operations
Philip Cook*	46	Senior Vice President – Chief Financial Officer
John C. Cirone*	58	Senior Vice President, General Counsel and Secretary
D. Wayne Blair	51	Vice President – Finance
C. Clay Blum	49	Vice President – Land
William S. Buckler	46	Vice President – Engineering Technology
Richard C. Buterbaugh	53	Vice President – Investor Relations & Corporate Planning
MarLu Hiller	45	Vice President – Treasurer
Stan G. Page	50	Vice President – U.S. Operations
John C. Regan*	38	Vice President, Controller and Chief Accounting Officer
Robert N. Wagner*	44	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. The following biographies describe the business experience of our executive and certain other 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. Prior to joining us, Mr. Darden was 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. Prior to working for Mercury, Mr. Darden 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.

P. 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.

D. WAYNE BLAIR became our Vice President – Finance in September 2007 after serving as our Controller and Chief Accounting Officer since 2002, and our Vice President – Controller since July 2000. Mr. Blair is a Certified Public Accountant with more than 25 years of experience in the oil and gas industry. He was employed by Sabine Corporation from 1980 through 1988 where he held the position of Assistant Controller. From 1988 through 1994, he served as Controller for a group of private businesses involved in the oil and gas industry. Prior to joining us in April 2000, he served as Controller for Mercury since 1996.

C. CLAY BLUM became our Vice President – Land in September 2007. Mr. Blum joined Quicksilver in 2003 as a Senior Staff Landman and most recently held the position of Director of Land, U.S. Operations. Mr. Blum has more than 27 years of oil and gas industry experience. Prior to joining Quicksilver he was employed by Emerald Operating and previous to that he was a Senior Landman for Union Pacific Resources (subsequently merged with Anadarko Petroleum Corporation). Mr. Blum also has numerous years of experience as an independent landman.

WILLIAM S. BUCKLER became our Vice President – Engineering Technology in October 2007, after serving as our Vice President – U.S. Operations since August 2005. He joined us in September 2003 as an Engineering Manager. Prior to that, Mr. Buckler was employed by Mitchell Energy Company LP (subsequently merged with Devon Energy) from 1984 to 2003, most recently as Operations/Engineering Supervisor.

RICHARD C. BUTERBAUGH became our Vice President – Investor Relations & Corporate Planning in March 2007. Mr. Buterbaugh has more than 30 years of energy finance experience. Prior to joining Quicksilver he was employed by Kerr-McGee Corporation (subsequently merged with Anadarko Petroleum Corporation) from 1989 to 2006, most recently as Vice President – Corporate Planning.

MARLU HILLER became our Vice President – Treasurer in January 2007. Since May 2000, she had served as our Treasurer. She is a Certified Public Accountant with more than 20 years of experience in public and oil and gas accounting. Prior to joining us in August of 1999 as Director of Financial Reporting and Planning, she was employed at Union Pacific Resources (subsequently merged with Anadarko Petroleum Corporation) serving in various capacities, including Manager of Accounting for Union Pacific Fuels, which was Union Pacific Resources' marketing company.

STAN G. PAGE became our Vice President – U.S. Operations in October 2007. Mr. Page has nearly 30 years of oil and gas operating experience prior to joining Quicksilver. Since beginning his career with Amoco in 1979, Mr. Page has held various positions of increasing responsibility, most recently as operations center manager for BP Amoco's East Texas region.

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 (January 2006 to September 2007), in which position he acted as principal financial executive of the division, Vice President of Compliance (June 2005 to December 2005), in which position he led various Sarbanes-Oxley Act compliance initiatives, and Director of Financial Reporting (October 2002 to May 2005), in which position he led various internal and external reporting initiatives. 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.

Because we have a limited operating history in certain of our operating areas, our future operating results are difficult to forecast, and our failure to sustain profitability in the future could adversely affect the market price of our common stock.

We may not maintain the current level of revenues, natural gas and crude oil reserves or production we now attribute to the properties contributed to us when we were formed and those developed and acquired since our formation. Any future growth of our natural gas and crude oil reserves, production and operations could place significant demands on our financial, operational and administrative resources. Our failure to sustain profitability in the future could adversely affect the market price of our common stock.

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

Our revenues, 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 facilities 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. For example, the closing NYMEX wholesale price of natural gas was at a six-year low of approximately $2.00 per Mcf for February 2002, and reached an all-time high of approximately $13.83 per Mcf for November 2005. During 2007, the closing NYMEX wholesale natural gas price ranged from a low of $5.43 per Mcf for September to a high of $7.59 per Mcf for June. 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 natural gas and oil 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 affect natural gas and crude oil prices, we cannot predict whether prices will remain at current levels, increase or decrease in the future.

If natural gas or crude oil prices decrease or our exploration and development efforts are unsuccessful, we may be required to record impairments of our oil and gas properties.

Our financial statements are prepared in accordance with generally accepted accounting principles. The reported financial results and disclosures were developed using certain significant accounting policies, practices and estimates, which are discussed in the Management's Discussion and Analysis of Financial Condition and Results of Operations section of this annual report. We employ the full cost method of accounting 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. An impairment to the carrying value of our oil and gas properties could result if natural gas, NGL and/or crude oil prices were to drop precipitously at a reporting period end and remain depressed for a period of time. Future price declines or increased operating and capitalized costs without incremental increases in natural gas and crude oil reserves could also require us to record a significant impairment expense.

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 revenues, 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 natural gas, NGL and crude oil prices and other factors, many of which are beyond our control.

At December 31, 2007, approximately 38% 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 natural gas, NGL and crude oil reserves and the costs associated with these reserves in accordance with industry standards and SEC requirements, 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.

You should not assume that the present value of future net cash flows disclosed in this annual report is the current market 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 generally based on prices and costs as of the date of the estimate. 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 natural gas and oil industry in general will affect the appropriateness of the 10% discount factor.

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

Approximately 42% of our 2007 production was from Texas, approximately 29% was from the Northeast Operations and approximately 27% was from Alberta, Canada. With the November 1, 2007 divestiture of our Northeast Operations, our production concentration in Texas and Canada has increased. 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.

We conduct our Canadian operations through Quicksilver Resources Canada Inc. At December 31, 2007, our proved Canadian reserves were estimated to be 328 Bcf. Capital expenditures relating to our Canadian operations are budgeted to be approximately $90 million in 2008, constituting approximately 10% of our total 2008 budgeted capital expenditures.

We expect that our 2008 Canadian capital budget will be funded from Canadian operating cash flow. If our revenues decrease as a result of lower natural gas or crude oil prices or otherwise, we may not be able to fund our entire 2008 Canadian capital budget, or may opt to increase our Canadian debt levels to fund 2008 capital expenditures. While our results to date indicate that net recoverable reserves on CBM lands could be substantial, we can offer you no assurance that development will occur as scheduled or that actual results will be in accordance with estimates.

Other risks of our operations in Canada include, among other things, 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 and expect to continue to experience capital expenditure and working capital needs, particularly as a result of increases in our property acquisition and drilling activities that are in excess of our cash generated from our operations. In the future, we will likely require additional financing in addition to cash generated from our operations to fund our planned growth. If revenues decrease as a result of lower natural gas, NGL or crude oil 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 acquisition, development drilling and other 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 natural gas and oil 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 natural gas and oil 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 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 natural gas, NGL and crude oil reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. 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, production and cash flow through exploration and development of our existing properties coupled with possible acquisitions of prospective non-producing properties and, to a lesser extent, producing properties. We cannot assure you, however, that our planned exploration, development projects or acquisition activities will result in meaningful additional reserves or that we will have continuing success drilling productive wells. Furthermore, while our revenues may increase if prevailing natural gas, NGL and crude oil prices increase materially, our finding costs for additional reserves also could increase.

We cannot assure distributions on, or the recorded investment value for, our BBEP interests.

We own a 32% limited partner interest in BBEP from which we expect to receive cash flows in the form of distributions. We have no management oversight or influence over BBEP or its financial condition, results of operations or cash flows, and are indirectly subject to the risks associated with BBEP's business and operations. Moreover, the management of BBEP has discretion over whether any distributions are made to unitholders and the amount of those distributions, if any.

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 a temporary or permanent impairment of our limited partner interest in BBEP.

We depend on KGS to gather, process and transport most of our Barnett Shale gas production, and we own more than 70% of KGS.

In connection with the KGS IPO, among other transactions, we transferred to KGS most of our pipeline gathering system located in the southern portion of the Fort Worth Basin (the "Cowtown Pipeline") and our natural gas processing plant located in Hood County, Texas (the "Cowtown Plant"), and we entered into an agreement for 10 years with KGS under which we are obligated to offer to KGS the right to provide gathering and processing services for substantially all of our production in Hood, Somervell, Johnson, Tarrant, Hill, Parker, Bosque and Erath Counties in North Texas and are charged specified fees. KGS has the option to purchase certain pipeline assets from us at historical cost within two years after those assets are complete and commence commercial service. KGS is obligated to purchase the Lake Arlington Dry System and the Hill County Dry System from us at fair market value within two years after those assets commence commercial service.

As a result of the transactions and arrangements described above, we have diminished control over assets that are important to our business and operations, we are committed to transactions that will not necessarily be economically advantageous at the times at which they are ultimately consummated and increased demands have been placed on certain of our personnel who perform services for both us and KGS. If our use of assets transferred to KGS is interrupted due to factors beyond our control, the commitments that we have to KGS prove to be uneconomic or the effectiveness of our management personnel is decreased due to their responsibilities to KGS, we may experience an adverse effect on our business, results of operations and financial condition.

Furthermore, through our ownership interest in KGS, we share in KGS' results of operations and may be entitled to distributions from KGS. Accordingly, we are indirectly 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 our industry;
- actions taken by unaffiliated operators, processors and transporters;
- 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 budgeted costs or expenditures;
- the effects of existing and future laws and governmental regulations;
- the effects of future litigation; and
- other factors discussed in KGS' Registration Statement on Form S-1 (No. 333-140599) 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.

At December 31, 2007, 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 the owners of these facilities 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 Chairman, our CEO and our other executive officers and key technical personnel. There is a risk that the services of these individuals will not be available to us in the future. Because competition for experienced personnel in the natural gas and oil industry is intense, we may not be able to find acceptable replacements with comparable skills and experience in the natural gas and oil industry. Accordingly, the loss of the services of one or more of these individuals could have a detrimental 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 natural gas and oil companies for property acquisitions. We also compete for the equipment and labor required to develop and operate these 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 natural gas and oil 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 fluctuations in the prices for our production, we have entered into financial hedging arrangements which tend to limit the benefit we would receive from increases in the prices of natural gas, NGLs and crude oil. 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 and crude oil market prices exceeding our swap prices requires us to make payment for the settlement of our hedge derivatives on the fifth day of the production month for natural gas hedges, and the fifth day after the production month for NGL and crude oil hedges.

If we choose not to engage in hedging arrangements in the future, we may be more adversely 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.

There is currently a high demand for drilling equipment and supplies. Higher natural gas, NGL and oil prices generally stimulate increased demand and result in increased prices for drilling equipment, crews and associated supplies, equipment and services. We believe that this high demand and increased prices could continue. Accordingly, we cannot assure you that we will be able to 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 in the future. 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 may be changed from time to time in response to economic or political conditions. Matters that are typically regulated include:

- discharge permits for drilling operations;
- 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 natural gas and crude oil 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 cost of servicing our debt could adversely affect our business; and such risk could increase if we incur more debt.

At December 31, 2007, we had total consolidated debt of $813.9 million. Subject to the limits contained in the loan agreements governing our senior secured revolving credit facilities and the indenture governing our senior subordinated notes, we may incur additional debt. Our ability to borrow under our senior secured revolving credit facilities is subject to the quantity of proved reserves attributable to our natural gas, NGL and crude oil properties and other assets, including our units owned in BreitBurn. One of our senior secured revolving credit facilities enables us to borrow significant amounts in Canadian dollars to fund and support our operations in Canada. Such indebtedness exposes us to currency exchange risk associated with the Canadian dollar. If we incur additional indebtedness or fail to increase the quantity of proved reserves attributable to our natural gas and crude oil properties, 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 on our indebtedness, including, among others, operating expenses and principal payments under our senior secured revolving credit facilities, our senior subordinated notes and our convertible subordinated debentures as well as partial funding of our planned capital expenditures. Our level of indebtedness relative to our proved reserves and these significant demands on our cash resources could have important effects on our business and on your investment in Quicksilver. 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 under our senior secured revolving credit facilities if the quantity of proved reserves attributable to our natural gas and crude oil properties are insufficient to support our level of borrowings under such credit facilities;

- limit our flexibility in planning for, or reacting to, changes in the natural gas and oil industry;

- place us at a competitive disadvantage compared to our competitors that have lower debt service obligations and significantly greater operating and financing flexibility than we do;

- limit our financial flexibility, including our ability to borrow additional funds;

- increase our interest expense if interest rates increase, because certain of our borrowings are at variable rates of interest;

- limit our ability to make capital expenditures to develop our properties;

- increase our vulnerability to exchange risk associated with Canadian dollar denominated indebtedness and international operations in Canada;

- increase our vulnerability to general adverse economic and industry conditions; and

- result in an event of default upon a failure to comply with financial covenants contained in our senior secured revolving credit facilities and the indenture governing our senior subordinated notes, which, if not cured or waived, could have a material adverse effect on our business, 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, our financial condition, results of operations and prospects and other factors, many of which are beyond our control.

If we are unable to service our indebtedness 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.

There can be no assurance that any of these strategies could be implemented on satisfactory terms, if at all.

Our senior secured revolving credit facilities and senior subordinated notes restrict our ability and the ability of some of our subsidiaries to engage in certain activities.

The loan agreements governing our senior secured revolving credit facilities and the indenture governing our senior subordinated notes 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 to exist certain liens;

- enter into 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.

The loan agreements for our senior secured revolving credit facility and the indentures governing our senior subordinated notes contain certain covenants, which, among other things, require the maintenance of a minimum current ratio, a minimum collateral coverage ratio, a minimum earnings (before interest, taxes, depreciation, depletion and amortization, non-cash income and expense, and exploration costs) to interest expense ratio, and a minimum earnings (before interest, taxes, depreciation, depletion, accretion and amortization, non-cash income and expense and exploration costs) to fixed charges ratio. Our ability to borrow under our senior secured revolving credit facilities is dependent upon the quantity of proved reserves attributable to our natural gas and crude oil properties. Our ability to meet these covenants or requirements may be affected by events beyond our control, and we cannot assure you that we will satisfy such covenants and requirements.

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 covenants in our loan agreements or the indenture governing our senior subordinated notes, or any instrument governing our future indebtedness, or our inability to maintain the financial ratios described above could result in an event of default under the applicable instrument. Upon the occurrence of such an event of default, the applicable creditors could, subject to the terms and conditions of the applicable instrument, 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 that would be triggered by such default or acceleration would also be subject to acceleration upon the occurrence of such default or acceleration. If we were unable to repay amounts due under our senior secured revolving credit facilities, the creditors could proceed against the collateral granted to them to secure such indebtedness. If the payment of our indebtedness is accelerated, there can be no assurance that our assets would be sufficient to repay in full such indebtedness and our other indebtedness that would become due as a result of any acceleration. The above restrictions could limit our ability to obtain future financing and may prevent us from taking advantage of attractive business opportunities.

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 Quicksilver Energy, L.P., which is primarily owned by members of the Darden family, beneficially own approximately 34% of our common stock as of December 31, 2007. As a result, these entities and individuals will generally be 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 notes 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 doing well.

Our shares that are eligible for future sale may have an adverse effect on the price of our common stock. There were over 158 million shares of our common stock outstanding at December 31, 2007. Approximately 102 million of these shares are freely tradable without substantial restriction or the requirement of future registration under the Securities Act. In addition, the necessary restrictions for our contingently convertible debentures have been satisfied and are now convertible at their holder's option, which based on the conversion rate in effect at December 31, 2007, could result in the issuance of an aggregate of 9,816,256 shares of our common stock. In addition, at December 31, 2007 we had 1,021,912 options outstanding to purchase shares of our common stock as detailed in Note 19 to the consolidated financial statements included in "Item 8 — Financial Statements and Supplementary Data."

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. The provisions described above and the stockholder rights plan could impede a merger, consolidation, takeover or other business combination involving us or discourage a potential acquirer from making a tender offer or otherwise attempting to take control of 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 2007 developments can be found in Item 1 of this annual report, which is incorporated herein by reference.

ITEM 3. *Legal Proceedings*

On November 7, 2001, Quicksilver Resources Inc. filed a lawsuit against CMS Marketing Services and Trading Company ("CMS") in the 236th Judicial District Court of Tarrant County, Texas. The suit alleged that CMS committed fraud when it entered into a 10-year contract (the "CMS Contract") with us 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. We sought unspecified damages and rescission of the contract. On May 15, 2007, the Court upheld a jury finding against CMS on the fraudulent inducement claim, rescinded the contract and rendered the contract void beginning May 15, 2007. CMS is appealing the judgment. We have also appealed the Court's judgment because we believe the contract was void from its inception rather than from the date of judgment entry. In May 2007, we ceased delivering natural gas pursuant to the CMS Contract as a result of the judgment entered by the court in the CMS lawsuit. Because the judgment was appealed by CMS we are required to post monthly appellate bonds securing the difference between $2.47 and the market price of natural gas that would have otherwise been delivered under the CMS Contract.

On October 13, 2006, we filed suit in the 342nd Judicial District Court in Tarrant County, Texas against Eagle Drilling, LLC and Eagle Domestic Drilling Operations, LLC (together "Eagle") regarding three contracts for drilling rigs in which we allege 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. Subsequently, on January 19, 2007, Eagle Domestic Drilling Operations, LLC and its parent, Blast Energy Services, Inc. filed for Chapter 11 bankruptcy in the United States Bankruptcy Court for the Southern District of Texas, Houston Division. Our suit against Eagle in Tarrant County was ultimately transferred to the Bankruptcy Court in Houston and has been consolidated with the Eagle/Blast bankruptcy. On September 17, 2007, Eagle Drilling, LLC, and Rod and Richard Thornton, sued us and P. Jeff Cook, our Executive Vice President-Operations, in the District Court of Cleveland County, Oklahoma for approximately $29 million in damages and an unspecified amount of punitive damages resulting from our decision to repudiate the rig contracts mentioned above. Based upon information currently available, we believe that the final resolution of this matter will not have a material effect on our financial condition, results of operations, or cash flows.

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 2007.

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[(1)]	LOW[(1)]
2007		
Fourth Quarter	$30.58	$23.44
Third Quarter	24.28	18.85
Second Quarter	24.77	19.74
First Quarter	20.42	16.48
2006(1)		
Fourth Quarter	$21.62	$14.34
Third Quarter	19.91	14.52
Second Quarter	23.09	14.63
First Quarter	26.38	16.53

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

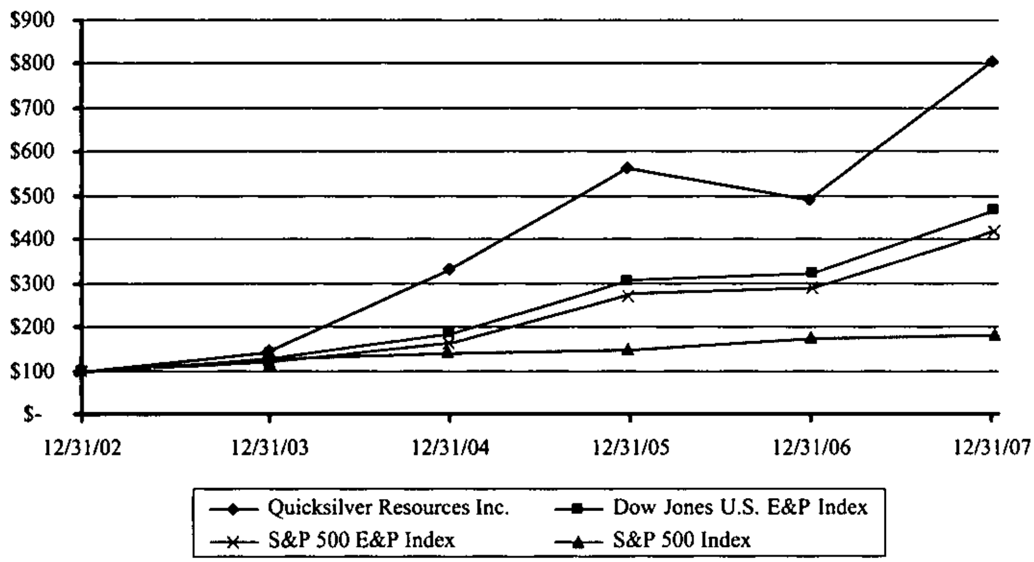
As of January 31, 2008, there were approximately 770 common stockholders of record.

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, our senior secured credit facility prohibits payments of dividends on our common stock and purchases of our common stock. The indenture for our senior subordinated notes prohibits payments of cash dividends on our common stock.

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"), the Dow Jones U.S. Exploration and Production Index (formerly the Dow Jones Secondary Oils Index, the "Dow Jones U.S. E&P Index") and the Standard & Poor's 500 Exploration and Production Index (the S&P 500 E&P Index") for the period from December 31, 2002 to December 31, 2007, assuming an initial investment of $100 and the reinvestment of all dividends, if any. In 2007, we changed from using the published industry index, the Dow Jones U.S. E&P Index, to the S&P 500 E&P Index because we believe the S&P 500 E&P Index is more easily accessible to our security holders.

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, 2007.

Period	Total Number of Shares Purchased [1][2]	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 2007	—	$ —	—	—
November 2007	872	$27.97	—	—
December 2007	662	$26.96	—	—
Total	1,534	$27.53	—	—

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

[2] Represents shares of common stock surrendered by employees to satisfy the Company's 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. Our financial information 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 document. The following information is not necessarily indicative of our future results.

Selected Financial Data

	Years Ended December 31,				
	2007[2]	2006	2005	2004	2003
	(In thousands, except for per share data and ratios)				
Operating Results Information					
Total revenues	$ 561,258	$ 390,362	$ 310,448	$179,729	$140,949
Operating income	803,581	174,196	149,129	60,693	48,498
Income before income taxes and minority interest	736,941	131,960	127,974	45,446	28,502
Income from continuing operations	479,378	93,719	87,272	31,272	18,505
Net income	479,378	93,719	87,434	31,272	16,208
Diluted earnings per share from continuing operations[1]	$ 2.86	$ 0.58	$ 0.54	$ 0.21	$ 0.14
Diluted earnings per common share[1]	2.86	0.58	0.54	0.21	$ 0.12
Dividends paid per share	—	—	—	—	—
Cash provided by operating activities	$ 319,104	$ 242,186	$ 140,242	$ 84,847	$ 49,602
Capital expenditures	1,020,684	619,061	331,805	215,106	137,895
Financial Condition Information					
Property, plant and equipment — net	2,142,346	1,679,280	1,112,002	802,610	604,576
Total assets	2,775,846	1,882,912	1,243,094	888,334	666,934
Long-term debt	813,817	919,117	506,039	399,134	249,097
Stockholders' equity	1,068,355	575,666	383,615	304,276	241,816
Debt to Proved Reserves ($/Mcfe)	$ 0.53	$ 0.59	$ 0.52	$ 0.41	$ 0.28

(1) Per share amounts have been adjusted to reflect a two-for-one stock split effected in the form of a stock dividend in June 2004, 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 income and net income for 2007 includes a gain of $628.7 million recognized from the divestiture of the Company's Northeast Operations and a charge of $63.5 million for a natural gas supply contract with a floor price of $2.49 per mcf for 25MMcfd for the remainder of the contract period (See Notes 4 and 5 to the Consolidated Financial Statements in Item 8, which are incorporated herein by reference).

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 on Form 10-K. We conduct our operations in two segments: (1) our 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

Management Discussion and Analysis of Financial Condition and Results of Operations 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.
- *Application of Critical Accounting Policies* — a discussion of critical accounting policies that represent choices between acceptable alternatives and/or require management judgments and estimates.
- *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.
- *Forward-Looking Statements* — cautionary information about forward-looking statements and a description of certain risks and uncertainties that could cause our actual results to differ materially from our historical results or our current expectations or projections.

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. Our focus is primarily on unconventional reservoirs where hydrocarbons are 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 operating income that allows us to conduct acquisition, exploration, exploitation, development and production activities to replace the reserves that have been produced.

At December 31, 2007, approximately 99% of our proved reserves were natural gas and natural gas liquids. Consistent with one of our business strategies, we have developed and applied the expertise gained in developing our formerly-owned Michigan properties to our Canadian projects in Alberta, Canada and our Barnett Shale interests in the Fort Worth Basin in Texas. Our Texas and Alberta reserves made up about 78% and 21%, respectively, of our proved reserves at December 31, 2007. The Delaware Basin in West Texas and the Mannville CBM in Alberta represent our most recent exploratory opportunities to apply this expertise.

For 2008, we plan to continue our focus on the development, exploitation and exploration of our properties in Texas and Alberta. We have allocated $650 million of our 2008 capital budget of $885 million for drilling activities. Approximately $790 million is allocated to projects in Texas and approximately $90 million is allocated to our Canadian projects. Approximately $160 million of the 2008 capital budget has been allocated to construction of natural gas processing and gathering assets, including $80 million associated with KGS.

Our Company focuses on three key value drivers:

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

The Company's reserve growth is dependent upon our ability to apply the Company's 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 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 the Company with opportunities to develop and exploit unconventional natural gas reservoirs which align our technical and operational expertise.

Our principal properties are well suited for production increases through development and exploitation drilling. We perform workover and infrastructure projects to reduce operating costs and increase current and future production. We regularly review our operated properties to determine if steps can be taken to profitably increase reserves and production.

In assessing our efforts, we measure the following key indicators: reserve growth; production; cash flow from operating activities; and earnings per share.

	Years Ended December 31,		
	2007	2006	2005
Reserve growth[(1)]	59%	46%	20%
Production (Bcfe)	77.9	61.3	51.4
Cash flow from operating activities (in millions)	$319.1	$242.2	$140.2
Diluted earnings per share	$ 2.86	$ 0.58	$ 0.54

(1) This ratio is calculated by subtracting adjusted beginning of the year proved reserves from 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 current year production from beginning of the year reserves.

The possibility of decreasing prices received for production is among the several risks that we face. We seek to manage this risk by entering into financial hedges. Our use of pricing collars and, to a lesser degree, fixed-price swaps covering a portion of our production helps to ensure a more predictable level of cash flow while allowing us to participate in a portion of any favorable price increases. This commodity price strategy enhances our ability to execute our development, exploitation and exploration programs, meet debt service requirements and pursue acquisition opportunities despite price fluctuations. If our revenues were to decrease significantly as a result of presently unexpected declines in natural gas prices or otherwise, we could be forced to curtail our drilling and lease acquisition activities. We might also be forced to sell some of our assets on an untimely or unfavorable basis.

Prices for natural gas and crude oil can fluctuate widely as evidenced by market prices varying between approximately $13 and $4 per Mcf within recent years. For February 2008 natural gas production, the wholesale price of natural gas was approximately $8.00 per Mcf. Assuming natural gas prices remain at relatively favorable levels, we expect to fund more of our capital expenditures with cash flow from operating activities; however, we do not expect our cash flow from our operations to be sufficient to satisfy our total budgeted capital expenditures. In addition to cash flow from our operations, we plan to use our credit facility, distributions received from BreitBurn, possible sales of assets and issuance of debt securities to fund our capital expenditures in 2008.

FINANCIAL RISK MANAGEMENT

We have established policies and procedures for managing risk within our organization, including internal controls. The level of risk we assume is based on our objectives and capacity to manage risk.

Our primary risk exposure is related to natural gas, crude oil and related commodity prices. We have mitigated the downside risk of adverse price movements through the use of swaps and collars; in doing so, we have also limited our ability to benefit from favorable price movements.

Commodity Price Risk

We enter into financial derivative contracts to mitigate our exposure to commodity price risk associated with anticipated future natural gas production. At December 31, 2007, we also have an obligation to deliver 25 MMcfd of natural gas under a long-term contract (the "Michigan Sales Contract") with a floor price of $2.49 per Mcf through March 2009. In December 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. For the fourth quarter of 2007, we recognized a loss of $63.5 million for the fair value of the Michigan Sales Contract through the end of its term in March 2009. In January 2008, we entered into a fixed-price natural gas swap covering all remaining volumes for the remaining contract period, which served to lock in the amount of our obligation under the Michigan Sales Contract.

We also enter into financial derivative contracts that include no-cost collars and fixed-price swaps to hedge our exposure to commodity price risk associated with our anticipated future production. As of December 31, 2007, approximately 65 MMcfd and 40 MMcfd of natural gas price collars and swaps, respectively, have been put in place to hedge 2008 anticipated production. Additionally, we have used fixed-price swaps to hedge 3,000 Bbld of NGL and 1,000 Bbld of crude oil of our anticipated 2008 production. Anticipated 2009 natural gas production of approximately 60 MMcfd has also been hedged using price collars. At December 31, 2007, 50% and 19% of our 2008 and 2009 expected production, respectively, is hedged with financial derivatives. We believe we will have more predictability of our natural gas and crude oil revenues as a result of these long-term sales and financial derivative contracts.

The following table summarizes our open derivative positions as of December 31, 2007 related to natural gas, NGL and crude oil production.

Product	Type	Contract Period	Volume	Weighted Avg Price Per Mcf or Bbl	Fair Value (In thousands)
Gas	Swap	Jan 2008-Dec 2008	25,000 Mcfd	$ 8.13	$ 2,893
Gas	Swap	Jan 2008-Dec 2008	7,500 Mcfd	8.13	868
Gas	Swap	Jan 2008-Dec 2008	5,000 Mcfd	8.14	597
Gas	Swap	Jan 2008-Dec 2008	2,500 Mcfd	8.15	307
Gas	Collar	Jan 2008-Mar 2008	5,000 Mcfd	7.50- 8.90	149
Gas	Collar	Jan 2008-Mar 2008	15,000 Mcfd	7.50- 8.70	422
Gas	Collar	Jan 2008-Mar 2008	10,000 Mcfd	8.00-15.65	735
Gas	Collar	Jan 2008-Mar 2008	10,000 Mcfd	8.00-15.00	700
Gas	Collar	Jan 2008-Mar 2008	10,000 Mcfd	9.00-12.00	1,502
Gas	Collar	Jan 2008-Mar 2008	10,000 Mcfd	9.00-12.05	1,508
Gas	Collar	Jan 2008-Dec 2008	20,000 Mcfd	7.50- 9.15	1,361
Gas	Collar	Apr 2008-Mar 2009	20,000 Mcfd	7.50- 9.35	(31)
Gas	Collar	Apr 2008-Mar 2009	20,000 Mcfd	8.00-10.20	3,034
Gas	Collar	Jan 2009-Dec 2009	20,000 Mcfd	7.50- 9.34	(1,594)
Gas	Collar	Jan 2009-Dec 2009	20,000 Mcfd	7.75-10.20	726
Gas	Collar	Jan 2009-Dec 2009	10,000 Mcfd	7.75-10.26	354
Gas	Basis	Jan 2008-Dec 2008	10,000 Mcfd		(612)
Gas	Basis	Jan 2008-Dec 2008	10,000 Mcfd		(612)
Gas	Sale	Jan 2008-Mar 2009[1]	25,000 Mcfd	2.49	(63,520)
NGL	Swap	Jan 2008-Dec 2008	1,000 Bbld	39.58	(5,380)
NGL	Swap	Jan 2008-Dec 2008	2,000 Bbld	45.94	(5,914)
Oil	Collar	Jan 2008-Dec 2008	500 Bbld	65.00-73.90	(3,538)
Oil	Collar	Jan 2008-Dec 2008	500 Bbld	65.00-77.45	(2,980)
				Total	$(69,025)

(1) Represents the Michigan Sales Contract

Utilization of our financial hedging program may result in natural gas, NGL and crude oil realized prices varying from market prices that we receive from the sale of natural gas, NGL and crude oil. As a result of settlements of derivative contracts, our revenue from natural gas, NGL and crude oil production was $51.5 million and $15.5 million higher and $41.8 million lower for 2007, 2006 and 2005, respectively.

Hedge ineffectiveness resulted in $1.0 million of net gains, $0.1 million of net losses and $0.1 million of net gains recorded to other revenue for 2007, 2006 and 2005, respectively.

Interest Rate Risk

There were no interest rate swaps utilized for the year ended December 31, 2007. Interest expense for the years ended December 31, 2006 and 2005 was $0.1 million and $0.3 million lower, respectively, as a result of interest rate swaps.

If interest rates on our variable interest-rate debt of $315.7 million, as of December 31, 2007, increase or decrease by one percentage point, our annual pretax income will decrease or increase by $3.2 million.

Credit Risk

Credit risk is the risk of loss as a result of non-performance by counterparties of their contractual obligations. We sell a portion of our natural gas production directly under long-term contracts with the remainder of production sold at spot or short-term contract prices. All our production is sold to large trading companies and energy marketing companies, refineries and other users of petroleum products. We also enter into hedge derivatives with financial counterparties. We monitor 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 our established policy. Each customer and/or counterparty is reviewed as to credit worthiness prior to the extension of credit and on a regular basis thereafter.

While we follow our credit policies at the time we enter into sales contracts, the credit worthiness of counterparties could change over time. The credit ratings of the parent company of the counterparty to the Michigan Sales Contract was downgraded in early 2003 and remains below the credit ratings required for the extension of credit to new customers, although we maintain a liability to them pursuant to the contract terms.

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. We manage performance risk through management of credit risk. Each customer and/or counterparty is reviewed as to credit worthiness prior to the extension of credit and on a regular basis thereafter.

Foreign Currency Risk

Our Canadian subsidiary uses the Canadian dollar as its functional currency. To the extent that business transactions in Canada are not denominated in Canadian dollars, we are exposed to foreign currency exchange rate risk. For the year ended December 31, 2007, non-functional currency transactions resulted in a loss of $0.8 million, reported in the statement of income. For the years ended December 31, 2006 and 2005, any gains or losses on such transactions were less than $0.1 million.

While 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 $23 million at December 31, 2007.

APPLICATION OF CRITICAL ACCOUNTING POLICIES

Management discusses with our Audit Committee the development, selection and disclosure of our critical accounting policies and estimates and the application of these policies and estimates. Our consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States. We believe our accounting policies are appropriately selected and applied.

Use of Estimates

In preparing the financial statements, our management makes informed judgments and estimates that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the reporting period. On an ongoing basis, management reviews its estimates, including asset retirement obligations, litigation, income taxes and determination of proved reserves. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates.

Oil and Gas Properties

We use the full cost method of accounting 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. The carrying amount of oil and gas properties also includes estimated asset retirement costs recorded based on the fair value of the asset retirement obligation. Gain or loss on the sale or other disposition of oil and gas properties is generally not recognized unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country. The application of the full cost method of accounting for oil and gas properties generally results in higher capitalized costs and higher depletion rates compared to its alternative, the successful efforts method. The sum of net capitalized costs and estimated future development and dismantlement costs for each cost center is depleted on the equivalent unit-of-production basis using proved oil and gas reserves as determined by independent petroleum engineers.

Ceiling Test

Our use of the full cost method requires us to perform a ceiling test quarterly pursuant to SEC Regulation S-X Rule 4-10. The ceiling test is an impairment test performed on a country-by-country basis that determines a limitation, or ceiling, on the book value of oil and gas properties, which is generally the after-tax value of the future net cash flows from proved natural gas and crude oil reserves, including the effect of cash flow hedges, discounted at 10% per annum. Applying the test, we compare the full cost ceiling limitation to the net book value of our oil and gas properties reduced by the related net deferred income tax liability and asset retirement obligations. If the net book value reduced by the related net deferred income tax liability and asset retirement obligations exceeds the full cost ceiling limitation, a non-cash impairment expense is required. A charge to income for impairment could create a significant loss for a particular period; however, future depletion expense would be reduced. The ceiling test is affected by a decrease in net cash flow from reserves due to higher operating or capital costs or reduction in market prices for natural gas, NGL and crude oil. These changes can reduce the amount of economically producible reserves.

Oil and Gas Reserves

Proved oil and gas reserves, as defined by SEC Regulation S-X Rule 4-10, 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 (i.e., prices and costs as of the date the estimate is made). 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. Decreases in prices, for example, may cause a reduction in some proved reserves due to reaching economic limits sooner. A material change in the estimated volumes of reserves could have an impact on the depletion rate calculation and the financial statements.

Derivative Instruments

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 on our balance sheet qualifying derivative instruments as either assets or liabilities measured at fair value determined by reference to published future market prices and interest rates. The gains or losses deferred in other comprehensive income from the effective portions of derivative instruments that qualify as hedges are recognized as income or expense in the period in which the hedged transactions are realized. Gains or losses on 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. The ineffective portion of hedges is recognized currently in earnings.

The fair value of our natural gas and crude oil derivatives and associated firm sales commitments as of December 31, 2007 was estimated based on published market prices of natural gas and crude oil for the periods covered by the contracts and the value confirmed by a counterparty. Estimates were determined by applying the net differential between the prices in each derivative and commitment and market prices for future periods, as adjusted for estimated basis, to the volumes stipulated in each contract to arrive at an estimated future value. This estimated future value was discounted on each contract at rates commensurate with federal treasury instruments with similar contractual lives.

Asset Retirement Obligations

We have obligations to remove equipment and restore land at the end of oil and gas production operations or at the cessation of our processing activities. Our removal and restoration obligations are primarily associated with plugging and abandoning wells and associated production facilities. The estimated fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets is recorded in the periods in which it is legally or contractually incurred. When the liability is recorded, we increase the carrying amount of the related long-lived asset. The liability is accreted to the fair value at the time of the settlement over the useful life of the asset, and the capitalized cost is depleted or depreciated over the useful life of the related asset.

The fair value of the liability associated with these retirement obligations is determined using significant assumptions, including current estimates of the plugging and abandonment or retirement, annual inflation of these costs, the productive life of the asset and our risk adjusted costs to settle such obligations discounted using our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the asset obligation are recorded with an offsetting change to the carrying amount of the related long-lived asset, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long life of most of our oil and gas assets, the costs to ultimately retire these assets may vary significantly from previous estimates.

Stock-based Compensation

We adopted SFAS No. 123(R) on January 1, 2006. We previously accounted for stock awards under the recognition and measurement principles of APB No. 25, *Accounting for Stock Issued to Employees*, and related Interpretations. Prior to January 1, 2006, stock-based employee compensation expense for restricted stock and stock unit grants was reflected in net income, but no compensation expense was recognized for options granted with an exercise price equal to the market value of the underlying common stock on the date of grant. SFAS No. 123(R) requires the cost resulting from all share-based payment transactions be recognized in the financial statements at their fair value on the grant date.

We adopted SFAS No. 123(R) using the modified prospective application method described in the statement. Under the modified prospective application method, we have applied the standard to awards made after adoption. Additionally, compensation cost for the unvested portion of stock awards outstanding as of January 1, 2006 has been recognized as compensation expense as the requisite service is rendered after

January 1, 2006. The compensation cost for unvested stock awards granted before adoption of SFAS No. 123(R) has been attributed to periods beginning January 1, 2006 using the attribution method that was used under SFAS No. 123.

Prior to the adoption of SFAS 123(R), we presented any tax benefits of deductions resulting from the exercise of stock options within operating cash flows in the condensed consolidated statements of cash flow. SFAS No. 123(R) requires tax benefits resulting from tax deductions in excess of the compensation cost recognized for those options ("excess tax benefits") to be classified and reported as both an operating cash outflow and a financing cash inflow upon adoption of SFAS No. 123(R).

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 that we expect will be in effect in years in which the temporary differences reverse. QRCI computes taxes at rates in effect in Canada. U.S. deferred tax liabilities are not recognized on profits that are expected to be permanently reinvested by QRCI and thus are not considered available for distribution to us.

Off-Balance Sheet Arrangements

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

RESULTS OF OPERATIONS

Revenues

Natural Gas, NGL and Crude Oil Sales

Production Revenues:

	Years Ended December 31, 2007	2006	2005
		(In thousands)	
Texas	$237,464	$ 90,849	$ 35,526
Northeast Operations	123,927	164,060	199,116
Other U.S.	11,226	10,846	9,978
Corporate and hedging	20,224	4,780	(34,905)
Total U.S.	392,841	270,535	209,715
Canada	152,248	116,005	96,489
Total	$545,089	$386,540	$306,204

Average Daily Production:

	Natural Gas			NGL			Oil and Condensate			Equivalent Total		
	2007	2006	2005	2007	2006	2005	2007	2006	2005	2007	2006	2005
		(MMcfd)			(Bbld)			(Bbld)			(MMcfed)	
Texas	50.1	23.9	9.0	6,395	1,579	185	349	215	66	90.6	34.7	10.5
Northeast Operations	56.1	71.7	78.3	331	419	386	799	930	972	62.9	79.8	86.5
Other U.S.	0.3	0.3	0.2	29	31	32	452	463	478	3.2	3.3	3.3
Total U.S.	106.5	95.9	87.5	6,755	2,029	603	1,600	1,608	1,516	156.7	117.8	100.3
Canada	56.8	50.0	40.6	13	14	8	—	—	—	56.9	50.0	40.7
Total	163.3	145.9	128.1	6,768	2,043	611	1,600	1,608	1,516	213.6	167.8	141.0

Average Realized Prices:

	Natural Gas			NGL			Oil and Condensate			Equivalent Total		
	2007	2006	2005	2007	2006	2005	2007	2006	2005	2007	2006	2005
		(MMcfd)			(Bbld)			(Bbld)			(MMcfed)	
Texas	$6.65	$7.22	$9.54	$45.70	$39.56	$43.65	$72.37	$63.62	$57.29	$7.18	$7.18	$9.30
Northeast Operations	4.92	5.25	6.12	37.36	35.27	36.36	63.81	62.33	53.90	5.40	5.63	6.31
Other U.S.	4.68	6.85	8.53	52.35	46.55	41.80	61.49	56.25	50.00	9.63	9.03	8.27
Total U.S.	6.40	5.90	5.42	43.22	38.78	38.88	63.87	59.99	50.50	6.87	6.29	5.73
Canada	7.33	6.35	6.50	48.02	49.03	53.91	—	—	—	7.33	6.35	6.50
Total	$6.73	$6.05	$5.76	$43.23	$38.85	$39.08	$63.87	$59.99	$50.50	$6.99	$6.31	$5.95

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

	Natural Gas	Oil	NGL	Total
		(In thousands)		
Revenue for 2005	$269,547	$27,947	$ 8,710	$306,204
Volume changes	39,315	2,008	20,319	61,642
Price changes	13,495	5,250	(51)	18,694
Revenue for 2006	$322,357	$35,205	$ 28,978	$386,540
Volume changes	42,735	(171)	74,546	117,110
Price changes	35,897	2,279	3,263	41,439
Revenue for 2007	$400,989	$37,313	$106,787	$545,089

Our natural gas sales for 2007 were $401.0 million and increased 24%, or $78.6 million, from 2006. Natural gas sales increased as a result of both a $0.68 per Mcf or 11% increase in realized natural gas prices and a 17.4 MMcfd or 12% increase in sales volumes as compared to 2006. Natural gas sales in the U.S. increased 10.6 MMcfd as a result of new wells placed into production, primarily in the Barnett Shale. The November 2007 divestiture of our Northeast Operations reduced our natural gas production as did natural production declines in this area. Drilling on our Canadian interests increased production by 6.8 MMcfd from 2006.

Crude oil and condensate sales for 2007 were $37.3 million which was $2.1 million or 6% higher than crude oil and condensate sales for 2006. A realized $3.88 per Bbl increase in prices contributed almost all of this increase as aggregate production was flat with 2006. Production in 2007 from our Barnett Shale interests increased to offset production declines in our Northeast Operations as well as the November divestiture of our Northeast Operations.

Sales of NGLs for 2007 were $106.8 million, $77.8 million or almost three times higher than 2006 NGL sales. The increase was primarily the result of an incremental 1,724 MBbl or 231% increase in NGL production resulting from Texas natural gas production and processing during 2007, which yielded an additional $74.5 million of revenues. Also, more favorable pricing of $4.38 per Bbl contributed an increase of $3.3 million as compared to 2006.

Our natural gas sales for 2006 were $322.4 million and increased 20%, or $52.8 million, from 2005. Natural gas sales increased as a result of both a $0.29 per Mcf or 5% increase in realized natural gas prices and a 17.8 Bcf or 14% increase in sales volumes as compared to 2005. Natural gas sales in the U.S. increased 3.1 Bcf as a result of new wells placed into production, primarily in the Barnett Shale, despite natural production declines in our Northeast Operations. Drilling on our Canadian interests increased production by 3.4 Bcf from 2005.

Crude oil and condensate sales for 2006 were $35.2 million which was $7.3 million or 26% higher than crude oil and condensate sales for 2005. A realized $9.49 per Bbl increase in prices contributed almost $5.3 million of the $7.3 million increase. Production in 2006 from our Barnett Shale interests increased as we placed additional wells into production during the offsetting natural production declines for existing wells.

Sales of NGLs for 2006 were $29.0 million, an increase of $20.3 million or more than 200% from 2005 NGL sales. The increase was the result of an incremental 523 MBbl of NGL production resulting from Texas natural gas production and processing during 2006.

Other Revenues

Other revenue, consisting primarily of revenue from the processing, gathering and marketing of natural gas, was $16.2 million for 2007, an increase of $12.3 million compared with 2006. This increase is primarily due to $5.1 million of higher throughput from third parties in our gathering and processing assets, including KGS. Also, higher Canadian government grants for new drilling techniques yielded an increase of $4.3 million from 2006 and hedge ineffectiveness in 2007 resulted in an increase of $1.0 million.

Other revenue was $3.8 million for 2006 or $0.4 million lower than 2005. The decrease was primarily the result of less revenue earned from Canadian tax credits when compared to 2005.

Operating Expenses

Oil and Gas Production Expenses

	Years Ended December 31,					
	2007		2006		2005	
	(In thousands, except per unit amounts)					
		Per mcfe		Per mcfe		Per mcfe
Texas	$ 54,065	$1.64	$24,797	$1.96	$ 6,661	$1.74
Northeast Operations	48,911	2.13	44,968	1.54	44,093	1.40
Other U.S.	3,471	3.13	3,486	2.97	3,328	2.77
Total U.S.	106,447	1.86	73,251	1.70	54,082	1.48
Canada	30,384	1.46	21,925	1.20	15,306	1.03
Total	$136,831	$1.76	$95,176	$1.55	$69,388	$1.35

2007 production expense increased by $41.7 million or 44% from 2006 levels, primarily due to costs associated with higher production levels. On a per mcfe basis, our costs increased 14% compared to 2006 levels. Overall costs increased in Texas, however, as our production and number of producing properties increased, our cost per unit of production decreased. Our 2007 production costs in our Northeast Operations reflect $6.3 million of employee severance cost associated with the November divestiture. Northeast Operations unit costs were also impacted by the production declines. The total cost increases reflect salary increases of $3.7 million associated with headcount increases. Our Canadian costs increased $8.5 million, including an estimated $1.3 million due to currency effects of the strengthening Canadian dollar, primarily as a result of $1.4 million higher gathering and processing costs, $2.0 million in increased direct operating cost associated with new producing properties and more than $5.1 million of overhead costs, including higher salaries, stock-based compensation, incentive compensation and rent.

Production expense in 2006 increased $24.0 million or 34% from 2005 primarily due to increased production volumes in Texas, which resulted in a lower cost per Mcfe produced. The increase in Texas also reflects increased gathering and processing costs associated with increased throughput and capacity on our midstream assets. In our Northeast Operations, production costs were roughly flat, although the cost per Mcfe produced was adversely impacted by the natural production declines. The $6.6 million increase in Canada, including an estimated $1.0 million currency effect of the strengthening Canadian dollar, primarily resulted from a $1.7 million increase in gathering and processing costs and $3.7 million increase in compensation costs, reflective of 20% more employees and higher stock-based compensation and benefits.

Production and Ad Valorem Taxes

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.

Production and ad valorem tax expense for 2006 was relatively flat when compared to 2005 as a $1.9 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 emanating from our drilling programs and midstream expansion 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,					
	2007		2006		2005	
		Per Mcfe		Per Mcfe		Per Mcfe
	(In thousands, except per unit amounts)					
Depletion						
U.S.	$ 65,020	$1.14	$40,051	$0.93	$29,597	$0.81
Canada	34,666	1.67	25,618	1.40	17,018	1.15
Total depletion	99,686	1.28	65,669	1.07	46,615	0.91
Depreciation of other fixed assets:						
U.S.	$ 15,389	$0.27	$ 8,715	$0.20	$ 5,858	$0.16
Canada	4,115	0.20	3,129	0.17	1,741	0.12
Total depreciation	19,504	0.25	11,844	0.19	7,599	0.15
Accretion	1,507	0.02	1,287	0.02	999	0.02
Total depletion, depreciation and accretion	$120,697	$1.55	$78,800	$1.29	$55,213	$1.07

Our 2007 depletion expense increased $34.0 million or 52% from 2006 depletion expense primarily as a result of our 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 lower 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 results from increased capacity at our Cowtown Gas Plant, additions to our Cowtown Pipeline and new Canadian gas processing facilities.

Our 2006 depletion expense increased $19.1 million or 41% from 2005. Our 2006 consolidated depletion rate increased $0.16 per Mcfe as a result of increased future development costs due in part to a higher percentage of undeveloped proved reserves for 2006 year-end as compared to 2005. Depreciation expense for 2006 was $4.2 million higher than 2005 depreciation expense primarily resulting from additions to our Canadian and KGS midstream assets.

General and Administrative Expense

General and administrative expense for 2007 was $47.1 million, an increase of $21.4 million or 84% from 2006. Expense for compensation and benefits grew $15.1 million, inclusive of 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 which was 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 pursuant to the KGS IPO and our Northeast Operations divestiture.

General and administrative expense for 2006 was $25.6 million, an increase of $6.5 million or 34% from 2005. Expense for compensation and benefits grew $5.3 million when compared to 2005. The increase included $3.4 million for stock compensation expense associated with grants of restricted stock, $1.5 million resulting from additional employees and annual raises and of $0.4 million for additional matching of employees' retirement plan contributions. The remaining increase was primarily the result of a $0.9 million increase in 2006 office-related expenses, primarily rent for additional office space, partially offset by decreases in several expense categories.

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. Also, we recorded a loss on the Michigan Sales Contract related to delivery of volumes to Michigan. Further information regarding these transactions is included in Item 8 of this annual report, which is incorporated herein by reference.

Interest Expense

For 2007, interest expense was $70.5 million after interest capitalization of $1.1 million, an increase of $26.5 million or 60% from 2006 and primarily the 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.

For 2006, interest expense was $44.1 million after interest capitalization of $1.9 million, an increase of $22.3 million from 2005 interest expense, which was primarily the result of higher debt balances, including the issuance of $350 million in principal amount of our senior subordinated notes in March of 2006. Interest expense for 2006 included a prepayment penalty of $0.8 million as a result of the early retirement of $70.0 million in principal amount of our second lien mortgage notes payable with a portion of the proceeds from the issuance of $350 million in principal amount of our senior subordinated notes. Recurring interest expense increased $14.0 million as a result of higher debt levels throughout 2006. Higher interest rates, including the Canadian prime rates paid on the Canadian debt outstanding under our senior credit facility, during 2006 contributed approximately $8.4 million to increased interest expense. These increases in 2006 interest expense were partially offset by an additional $0.8 million of interest capitalization relating to gas processing facilities in Texas and Canada.

Income Taxes

	Years Ended December 31,		
	2007	2006	2005
Income tax (in thousands)	$256,508	$38,150	$40,702
Effective tax rate	34.9%	28.9%	31.8%

Our 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 United States 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% plus the effects of tax rate reductions that were enacted in 2007 and income tax credits of approximately $1.1 million for SRED.

Our income tax expense for 2006 was $38.1 million which yielded the effective rate of 29%. Our U.S. deferred federal income tax provision of $27.5 million was established using the statutory U.S. federal rate of 35%. Expense for the 2006 period included the reversal of a deferred federal income tax liability of

$0.9 million as a result of the completion of IRS audits of a wholly-owned subsidiary for years prior to its acquisition by us. We also recognized a deferred state income tax expense of $1.6 million as a result of the Texas Margin Tax that was enacted in May 2006. The Canadian tax provision was approximately $9.0 million for 2006, which included a reduction of $3.8 million for the effect of federal and provincial tax rate reductions that were enacted in the second quarter of 2006.

LIQUIDITY, CAPITAL RESOURCES AND FINANCIAL POSITION

Cash Flow Activity

Operating Cash Flows

	Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Net cash provided by operating activities	$319,104	$242,186	$140,242

Cash flows provided by operating activities in 2007 were $319.1 million, an increase of $76.9 million or 32% from 2006. The higher cash flows result from a 27% production increase and an 11% realized price increase. The increase in net earnings and the effects of higher non-cash depletion contributed to the higher operating cash flows.

Cash flows provided by operating activities in 2006 were $242.2 million, a $101.9 million increase from operating cash flow for 2005. The 73% increase in operating cash flow was primarily the result of a 19% increase in production, which resulted in more revenues and higher earnings.

Investing Cash Flows

	Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Purchases of property, plant and equipment	$(1,020,684)	$(619,061)	$(331,805)
Return of investment from equity affiliates	9,635	1,923	533
Proceeds from sales of properties & equipment	741,297	5,113	9,693
Net cash used for investing activities	$ (269,752)	$(612,025)	$(321,579)

For each of the three years ended December 31, 2007, we have spent significant cash resources for the acquisition of exploration and producing properties. In addition, our expenditures for gas processing and gathering assets have grown significantly as part of our growth in the Barnett Shale in North Texas. In 2007, our investing cash flows also included net cash proceeds of $741.1 million from the divestiture of our Northeast Operations. Total property, plant and equipment costs incurred (purchases of property, plant and equipment plus net working capital changes related to acquisition of property, plant and equipment) by geographic segment for 2007, 2006 and 2005 are as follows:

Property and Equipment Costs Incurred

	United States	Canada	Consolidated
		(In thousands)	
2007			
Proved acreage	$ —	$ —	$ —
Unproved acreage	17,031	31,448	48,479
Development costs	213,180	53,439	266,619
Exploration costs	511,314	26,122	537,436
Gas processing and gathering	168,523	3,417	171,940
Administrative	19,093	647	19,740
Total	$929,141	$115,073	$1,044,214

	United States	Canada	Consolidated
		(In thousands)	
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
Gas processing and gathering	90,947	6,294	97,241
Administrative	3,162	585	3,747
Total	$527,699	$118,028	$ 645,727
2005			
Proved acreage	$ 821	$ 1,620	$ 2,441
Unproved acreage	48,419	3,784	52,203
Development costs	24,007	82,388	106,395
Exploration costs	109,148	9,829	118,977
Gas processing and gathering	49,107	20,390	69,497
Administrative	10,787	669	11,456
Total	$242,289	$118,680	$ 360,969

Capital costs incurred for development, exploitation and exploration activities in 2007 were $852.5 million. Those expenditures reflect our focus in two operating areas, the Fort Worth Basin in North Texas and our Canadian projects in the Western Sedimentary Basin in Alberta, Canada. In 2007, we drilled 244 (219 net) wells in the Fort Worth Basin and an additional 356 (184 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 reflect our focus in two operating areas, the Fort Worth Basin in North Texas and our Canadian projects in the Western Sedimentary Basin in Alberta, Canada. 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.

Capital expenditures for our 2005 development, exploitation and exploration activities were focused in two areas. Canadian development and exploration costs were $97.6 million. Our 2005 expenditures in Canada were focused on the development and exploitation of our ongoing CBM projects as well as exploration of additional CBM acreage. Canadian expenditures for gas processing facilities were $20.4 million. Our U.S. capital expenditures were primarily spent on development, exploitation and exploration of the Barnett Shale in the Fort Worth Basin. Total expenditures for our Texas projects were $153.6 million, including approximately $51.7 million for acreage in the Fort Worth and Delaware Basins. Expenditures for completion of the first phase of our Cowtown Pipeline and construction of our Cowtown Plant in the Fort Worth Basin were more than $49.2 million.

We currently estimate that our spending for property, plant and equipment in 2008 will be approximately $885 million, of which we have allocated $650 million for drilling activities, $160 million for gathering and processing facilities (including $80 million for KGS), $70 million for acquisition of additional leasehold interest and $5 million for other property and equipment.

Financing Cash Flows

	Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Cash flow provided by financing activities:			
Issuance of debt	$ 817,821	$ 694,682	$183,469
Repayments of debt	(968,557)	(350,754)	(13,079)
Debt issuance costs	(5,130)	(9,213)	(745)
Minority interest contributions	109,809	7,291	—
Minority interest distributions	(8,794)	—	—
Proceeds from exercise of stock options	21,387	19,689	2,894
Excess tax benefit on exercise of stock options	2,755	—	6,536
Purchase of treasury stock	(1,567)	(384)	(95)
Payment for fractional shares	—	—	(18)
Net cash (used for) provided by financing activities	$ (32,276)	$ 361,311	$178,962

Net cash flows from financing activities were significantly impacted by the KGS IPO and the divestiture of our Northeast Operations, which were consummated in 2007. 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.

Net cash provided by financing activities in 2006 was $361.3 million, primarily due to our issuance of $350 million in principal amount of Senior Subordinated Notes. We used $70 million of the proceeds of the Senior Subordinated Notes to retire our second lien mortgage notes in March 2006. We also used approximately $192.5 million of the proceeds to repay the borrowings then outstanding under the U.S. portion of our senior secured credit facility.

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, 2007, the borrowing base was equal to $750 million, 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 with consent of the lenders. 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 by QRCI. The facility offers the option to extend the maturity up to two additional years with requisite lender consent. 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 loan agreements for the credit facility prohibit the declaration or payment of dividends by us and contain certain financial covenants, which, among other things, require the maintenance of a minimum current ratio and a minimum earnings (before interest, taxes, depreciation, depletion and amortization, non-cash income and expense, and exploration costs) to interest expense ratio. In October 2007, the agents and lenders under the Company's senior secured credit facility consented to the BreitBurn Transaction. As a condition to such consent, among other things, the parties agreed to a reduction in the borrowing base from $1.1 billion to $750 million effective upon consummation of the BreitBurn Transaction. Following the completion of the BreitBurn Transaction, we used $654 million of the proceeds from the divestiture of our Northeast Operations to repay outstanding U.S. borrowings. The Company also agreed to pledge the equity interests in BreitBurn it received as part of the BreitBurn Transaction to secure its and QRCI's obligations under the credit facility. At

December 31, 2007, approximately $438 million was available for borrowing under our senior secured credit facility and we were in compliance with all covenants.

In connection with the KGS IPO, KGS entered into a five-year $150 million senior secured revolving credit facility ("KGS Credit Agreement"). With consent of the lenders, KGS has the option to extend the facility for up to two additional years and increase the facility up to $250 million. KGS must maintain certain financial ratios that can limit its borrowing capacity. The KGS Credit Agreement contains certain restrictive covenants which, among other things, require the maintenance of a maximum leverage ratio of debt to Consolidated EBITDA (as defined in the KGS Credit Agreement) and a minimum ratio of Consolidated EBITDA to interest expense. These financial covenants exclude certain amounts payable by KGS to its parent and the interest thereon. At December 31, 2007, KGS' borrowing capacity was $82.7 million, as limited by the facility's leverage ratio test and KGS had $5 million in borrowings outstanding under the KGS Credit Agreement. The KGS Credit Agreement prohibits the declaration or payment of distributions by the Partnership if an event of default then exists or would result from the payment of a distribution. KGS was in compliance with all covenants as of December 31, 2007.

As of December 31, 2007, 2006 and 2005, our total capitalization was as follows:

	Years Ended December 31, (In thousands)		
	2007	2006	2005
Long-term and short-term debt:			
Senior secured credit facility	$ 310,710	$ 421,123	$357,788
Senior subordinated notes	350,000	350,000	—
Convertible subordinated debentures	148,107	147,994	147,881
Second lien mortgage notes	—	—	70,000
KGS credit agreement	5,000	—	—
Various loans	34	400	746
Other	—	—	117
Total debt	813,851	919,517	576,532
Stockholders' equity	1,068,355	575,666	383,615
Total capitalization	$1,882,206	$1,495,183	$960,147

We believe that our capital resources are adequate to meet the requirements of our existing business. We anticipate that our 2008 capital expenditure budget of approximately $885 million will be funded by cash flow from operations, credit facility utilization and cash distributions received from BreitBurn. We may also consider the possible sale of assets and the possible issuance of debt securities to fund our 2008 capital expenditure budget.

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

Financial Position

The following impacted our balance sheet as of December 31, 2007, as compared to our balance sheet as of December 31, 2006:

- Our current and deferred derivative assets decreased $53.3 million and $3.4 million, respectively, as our current and deferred derivative obligations increased $64.1 million and $16.3 million, respectively. Our current and deferred derivative obligations include the $63.5 million fair value loss for the remaining term of the Michigan Sales Contract for which in December 2007 we determined we would no longer deliver a portion of our natural gas production under the contract. Additionally, our current deferred income tax liability decreased $21.4 million as a result overall lower valuations of our derivative valuations.

- The $463.1 million increase in our net property, plant and equipment resulted primarily from $1,044 million in capital expenditures for development, exploitation and exploration of our oil and gas properties as well as expansion of our gas processing and gathering assets partially offset by the divestiture of our Northeast Operations which had an allocated carrying value of $538.8 million.

- Long-term debt decreased due to utilization of the cash proceeds from the November 2007 divestiture of our Northeast Operations and the August 2007 KGS IPO which offset the borrowings associated with the exploration and development efforts throughout the year.

- As a result of the KGS IPO, we recognized a deferred gain of $79.3 million that will not be recorded in our results of operations until the expiration of the subordination period. Also, as a result of the KGS IPO, we decreased our ownership in KGS and accordingly carry $30.3 million of minority interest for KGS' outside ownership. See Note 3 to the financial statements included in Item 8 of this annual report, which is incorporated herein by reference, for additional information about the KGS IPO and the subordination period.

Contractual Obligations and Commercial Commitments

Contractual Obligations. Information regarding our contractual and scheduled interest obligations, at December 31, 2007, is set forth in the following table.

	Payments Due by Period				
Contractual Obligations	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
			(In thousands)		
Long-term debt	$ 815,744	$ 34	$ —	$315,710	$500,000
Scheduled interest obligations	281,526	28,448	83,250	55,500	114,328
Transportation contracts	103,069	2,940	29,975	21,017	49,137
Purchase obligations	65,517	42,017	23,500	—	—
Natural gas supply contract	63,520	49,310	14,210	—	—
Drilling rig contracts	60,932	29,109	31,823	—	—
Asset retirement obligations	21,849	645	183	122	20,899
Financial derivative obligations	16,656	14,538	2,118	—	—
Unrecognized tax benefits	10,609	—	10,609	—	—
Operating lease obligations	9,476	4,190	5,282	4	—
Total obligations	$1,448,898	$171,231	$200,950	$392,353	$684,364

- *Long-Term Debt.* As of December 31, 2007, we had $311 million outstanding under our senior secured credit facility, $150 million of contingently convertible debentures (before discount) and $350 million of senior subordinated notes and $5 million outstanding under the KGS credit facility. Based upon our debt outstanding and interest rates in effect at December 31, 2007, we anticipate interest payments, including our scheduled interest obligations of $28.4 million, to be approximately $46.7 million in 2008. We expect to increase borrowings under our senior secured credit facility to partially fund our capital spending program throughout 2008. Based on interest rates in effect at December 31, 2007, for each additional $10 million in borrowings, annual interest payments will increase by approximately $0.6 million. If the borrowing base under our senior secured credit facility were to be fully utilized by year-end 2008 at interest rates in effect at December 31, 2007, we estimate that interest payments would increase by approximately $13.2 million. If interest rates on our

December 31, 2007 variable debt balance of $315.7 million increase or decrease by one percentage point, our annual pretax income will decrease or increase by $3.2 million.

- *Scheduled Interest Obligations.* As of December 31, 2007, we had scheduled interest payments of $2.8 million annually on our $150 million of contingently convertible debentures due November 1, 2024 and $24.9 million annually on our $350 million of senior subordinated notes due March 31, 2016.

- *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 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, 2007, we were under contract to purchase goods and services for completion of a gas processing plant in Texas. Total remaining obligations for construction and completion of the gas processing plant were $65.5 million, including $9.1 million recognized through December 31, 2007. We expect to place the new gas processing plant into service during the first quarter of 2009.

- *Natural Gas Supply Contract.* 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 at December 31, 2007. In January 2008, we entered into a fixed-price natural gas swap covering all remaining volumes for the remaining contract period.

- *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 the specified day rate average of $21,500 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 $10.0 million balance of unrecognized tax benefits includes $8.6 million of amounts that, if recognized, would reduce our effective tax rate. The balance also includes $0.6 million for interest and penalties.

- *Operating Lease Obligations.* We lease office buildings and other property under operating leases. Our operating lease obligations include $3.1 million of future lease payments to an affiliate of Mercury, which is owned by members of the Darden family.

Commercial Commitments. We had the following commercial commitments as of December 31, 2007:

	Amounts of Commitments by Expiration Period				
Commercial Commitments	**Total**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**More than 5 Years**
			(In thousands)		
Standby letters of credit	$ 1,590	$ 1,590	$—	$—	$—
Surety bonds	13,231	13,231	—	—	—
Total	$14,821	$14,821	$—	$—	$—

- *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 credit facility and have an annual renewal option.
- *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.

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;
- competitive conditions in our industry;
- actions taken by third parties including operators, processors and transporters;
- 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.

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

RECENTLY ISSUED ACCOUNTING STANDARDS

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

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

The information called for by this Item is incorporated herein by reference to the information in Item 7 of this report under the heading "Financial Risk Management."

ITEM 8. ***Financial Statements and Supplementary Data***

QUICKSILVER RESOURCES INC.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S STATEMENT OF RESPONSIBILITIES

To the Stockholders of Quicksilver Resources Inc.:

Management of Quicksilver Resources Inc. is responsible for the preparation, integrity and fair presentation of its published consolidated financial statements. The financial statements have been prepared in accordance with U.S. generally accepted accounting principles and, as such, include amounts based on judgments and estimates made by management. The Company also prepared the other information included in the annual report and is responsible for its accuracy and consistency with the consolidated financial statements.

Management is also responsible for establishing and maintaining effective internal control over financial reporting. The Company's internal control over financial reporting includes those policies and procedures that pertain to the Company's ability to record, process, summarize and report reliable financial data. The Company maintains a system of internal control over financial reporting, which is designed to provide reasonable assurance to the Company's management and board of directors regarding the preparation of reliable published financial statements and safeguarding of the Company's assets. The system includes a documented organizational structure and division of responsibility, established policies and procedures, including a code of conduct to foster a strong ethical climate, which are communicated throughout the Company, and the careful selection, training and development of our people.

The Board of Directors, acting through its Audit Committee, is responsible for the oversight of the Company's accounting policies, financial reporting and internal control. The Audit Committee of the Board of Directors is comprised entirely of outside directors who are independent of management. The Audit Committee is responsible for the appointment and compensation of the independent registered public accounting firm. It meets periodically with management, the independent registered public accounting firm and the internal auditors to ensure that they are carrying out their responsibilities. The Audit Committee is also responsible for performing an oversight role by reviewing and monitoring the financial, accounting and auditing procedures of the Company in addition to reviewing the Company's financial reports. Internal auditors monitor the operation of the internal control system and report findings and recommendations to management and the Audit Committee. Corrective actions are taken to address control deficiencies and other opportunities for improving the system as they are identified. The independent registered public accounting firm and the internal auditors have full and unlimited access to the Audit Committee, with or without management, to discuss the adequacy of internal control over financial reporting, and any other matters which they believe should be brought to the attention of the Audit Committee.

Management recognizes that there are inherent limitations in the effectiveness of any system of internal control over financial reporting, including the possibility of human error and the circumvention or overriding of internal control. Accordingly, even effective internal control over financial reporting can provide only reasonable assurance with respect to financial statement preparation and may not prevent or detect misstatements. Further, because of changes in conditions, the effectiveness of internal control over financial reporting may vary over time.

Management assessed the Company's internal control system as of December 31, 2007 in relation to criteria for effective internal control over financial reporting described in "Internal Control — Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment, the Company has determined that, as of December 31, 2007, the Company's system of internal control over financial reporting was effective.

The consolidated financial statements have been audited by the independent registered public accounting firm, Deloitte & Touche LLP, which was given unrestricted access to all financial records and related data, including minutes of all meetings of stockholders, the Board of Directors and committees of the Board. Reports of the independent registered public accounting firm, which includes the independent registered public accounting firm's attestation of internal controls, are also presented within this document.

/s/ Glenn Darden	/s/ Philip Cook
President and Chief Executive Officer	Senior Vice President — Chief Financial Officer

Fort Worth, Texas
February 27, 2008

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, 2007 and 2006 and the related consolidated statements of income and comprehensive income, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2007. 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, 2007 and 2006, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123 (Revised 2004), *Share-Based Payment.*

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2007, 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 February 27, 2008 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Fort Worth, Texas
February 27, 2008

QUICKSILVER RESOURCES INC.

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2007 AND 2006

	2007	2006
	In thousands, except for share data	
ASSETS		
Current assets		
Cash and cash equivalents	$ 28,226	$ 5,281
Accounts receivable — net of allowance for doubtful accounts	90,244	76,521
Derivative assets at fair value	10,797	64,086
Current deferred income tax asset	18,946	—
Other current assets	42,188	25,076
Total current assets	190,401	170,964
Investments in and advances to equity affiliates	420,171	7,434
Property, plant and equipment — net		
Oil and gas properties, full cost method (including unevaluated costs of $215,228 and $191,665, respectively)	1,764,400	1,444,059
Other property and equipment	377,946	235,221
Property, plant and equipment — net	2,142,346	1,679,280
Derivative assets at fair value	354	3,753
Other assets	22,574	21,481
	$2,775,846	$1,882,912
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of long-term debt	$ 34	$ 400
Accounts payable	192,855	109,914
Income taxes payable	46,601	589
Accrued liabilities	54,981	67,108
Derivative liabilities at fair value	64,104	—
Current deferred tax liability	—	21,378
Total current liabilities	358,575	199,389
Long-term debt	813,817	919,117
Asset retirement obligations	23,864	25,058
Derivative liabilities at fair value	16,327	—
Other liabilities	10,609	—
Deferred income taxes	374,645	156,251
Commitments and contingencies (Note 16)		
Deferred gain on sale of partnership interests	79,316	—
Minority interests in consolidated subsidiaries	30,338	7,431
Stockholders' equity		
Preferred stock, par value $0.01, 10,000,000 shares authorized, none outstanding	—	—
Common stock, $0.01 par value, 200,000,000 shares authorized; 160,633,270 and 157,783,515 shares issued, respectively	1,606	1,578
Paid in capital in excess of par value	272,515	237,287
Treasury stock of 2,616,726 and 2,579,671 shares, respectively	(12,304)	(10,737)
Accumulated other comprehensive income	40,066	60,099
Retained earnings	766,472	287,439
Total stockholders' equity	1,068,355	575,666
	$2,775,846	$1,882,912

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

QUICKSILVER RESOURCES INC.

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME FOR THE YEARS ENDED DECEMBER 31, 2007, 2006 AND 2005

	2007	2006	2005
	In thousands, except for per share data		
Revenues			
Natural gas, NGL and crude oil sales	$545,089	$386,540	$306,204
Other	16,169	3,822	4,244
Total revenues	561,258	390,362	310,448
Operating expenses			
Oil and gas production expense	136,831	95,176	71,204
Production and ad valorem taxes	16,142	15,619	15,068
Other operating costs	2,792	1,461	1,661
Depletion, depreciation and accretion	120,697	78,800	55,213
General and administrative	47,060	25,636	19,087
Total expenses	323,522	216,692	162,233
Income from equity affiliates	661	526	914
Gain on sale of oil and gas properties	628,709	—	—
Loss on natural gas sales contract	(63,525)	—	—
Operating income	803,581	174,196	149,129
Other income — net	(3,887)	(1,825)	(585)
Interest expense	70,527	44,061	21,740
Income from continuing operations before income taxes and minority interest	736,941	131,960	127,974
Income tax expense	256,508	38,150	40,702
Minority interest expense, net of income tax	1,055	91	—
Income from continuing operations	479,378	93,719	87,272
Discontinued operations — net of income tax of $86	—	—	162
Net income	$479,378	$ 93,719	$ 87,434
Other comprehensive income — net of income tax			
Reclassification adjustments related to settlements of derivative contracts	(34,648)	(9,707)	26,892
Net change in derivative fair value	(14,794)	83,410	(49,743)
Foreign currency translation adjustment	29,409	(1,222)	3,707
Comprehensive income	$459,345	$166,200	$ 68,290
Earnings per common share — basic:			
From continuing operations	$ 3.08	$ 0.61	$ 0.58
From discontinued operations	—	—	—
Net income	$ 3.08	$ 0.61	$ 0.58
Earnings per common share — diluted:			
From continuing operations	$ 2.86	$ 0.58	$ 0.54
From discontinued operations	—	—	—
Net income	$ 2.86	$ 0.58	$ 0.54
Basic weighted average shares outstanding	155,475	153,413	151,431
Diluted weighted average shares outstanding	168,029	166,266	164,912

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, 2007, 2006 AND 2005

	2007	2006	2005
	In thousands, except for share data		
Preferred stock, $0.01 par value, 10,000,000 shares authorized none issued	$ —	$ —	$ —
Common stock, $0.01 par value, 200,000,000, 200,000,000 and 100,000,000 shares authorized			
Balance at beginning of year	1,578	1,547	1,529
Issuance of common stock — restricted stock	6	9	3
Issuance of common stock — stock options	22	22	15
Balance at end of year: 160,633,270, 157,783,515 and 154,729,151 shares issued at December 31, 2007, 2006 and 2005, respectively	1,606	1,578	1,547
Paid in capital in excess of par value			
Balance at beginning of year	237,287	211,083	199,938
Stock options exercised	21,365	19,667	2,877
Stock-based compensation expense recognized	11,108	6,537	1,732
Tax benefit related to stock options exercised	2,755	—	6,536
Balance at end of year	272,515	237,287	211,083
Treasury stock, at cost			
Balance at beginning of year	(10,737)	(10,353)	(10,258)
Acquisition of treasury stock	(1,567)	(384)	(95)
Balance at end of year: 2,616,726, 2,579,671 and 2,571,069 shares at December 31, 2007, 2006, and 2005, respectively	(12,304)	(10,737)	(10,353)
Accumulated other comprehensive income (loss)			
Deferred gains (losses) on hedge derivatives			
Balance at beginning of year	45,194	(28,509)	(5,658)
Reclassification adjustments related to settlements of derivative contracts	(34,648)	(9,707)	26,892
Net change in derivative fair value	(14,794)	83,410	(49,743)
Balance at end of year	(4,248)	45,194	(28,509)
Deferred foreign exchange adjustment			
Balance at beginning of year	14,905	16,127	12,420
Foreign currency translation adjustment	29,409	(1,222)	3,707
Balance at end of year	44,314	14,905	16,127
Total accumulated other comprehensive income (loss)	40,066	60,099	(12,382)
Retained earnings			
Balance at beginning of year	287,439	193,720	106,304
Payment for fractional shares	—	—	(18)
Adoption of FIN 48	(345)	—	—
Net income	479,378	93,719	87,434
Balance at end of year	766,472	287,439	193,720
Total stockholders' equity	$1,068,355	$575,666	$383,615

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, 2007, 2006 AND 2005

	2007	2006	2005
		In thousands	
Operating activities:			
Net income	$ 479,378	$ 93,719	$ 87,434
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation and accretion	120,697	78,800	55,213
Deferred income taxes	209,943	37,877	40,298
(Gain) loss from sale of properties	(627,348)	188	(35)
Non-cash loss (gain) from hedging and derivative activities	62,515	—	(462)
Stock-based compensation	11,243	6,546	1,732
Amortization of deferred charges	2,189	226	192
Amortization of deferred loan costs	2,050	2,070	1,429
Minority interest expense	1,055	91	—
Income from equity affiliates	(661)	(526)	(914)
Provision for doubtful accounts	(349)	701	108
Divestiture expenses	2,015	—	—
Changes in assets and liabilities			
Accounts receivable	(14,423)	(1,100)	(38,192)
Prepaid expenses and other assets	(4,144)	(4,495)	391
Accounts payable	18,939	15,193	1,963
Accrued and other liabilities	56,005	12,896	(8,915)
Net cash provided by operating activities	319,104	242,186	140,242
Investing activities:			
Purchases of property, plant and equipment	(1,020,684)	(619,061)	(331,805)
Return of investment from equity affiliates	9,635	1,923	533
Proceeds from sales of properties and equipment	741,297	5,113	9,693
Net cash used for investing activities	(269,752)	(612,025)	(321,579)
Financing activities			
Issuance of debt	817,821	694,682	183,469
Repayments of debt	(968,557)	(350,754)	(13,079)
Debt issuance costs	(5,130)	(9,213)	(745)
Minority interest contributions	109,809	7,291	—
Minority interest distributions	(8,794)	—	—
Proceeds from exercise of stock options	21,387	19,689	2,894
Excess tax benefits on exercise of stock options	2,755	—	6,536
Purchase of treasury stock	(1,567)	(384)	(95)
Payment for fractional shares	—	—	(18)
Net cash (used for) provided by financing activities	(32,276)	361,311	178,962
Effect of exchange rate changes in cash	5,869	(509)	746
Net increase (decrease) in cash	22,945	(9,037)	(1,629)
Cash and cash equivalents at beginning of period	5,281	14,318	15,947
Cash and cash equivalents at end of period	$ 28,226	$ 5,281	$ 14,318

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

QUICKSILVER RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2007, 2006 AND 2005

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 and 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, 2007, substantial portions of Quicksilver's reserves are located in Texas, the Rocky Mountains and Alberta, Canada with U.S. offices in Fort Worth, Texas, Cut Bank, Montana; Granbury, Texas and a Canadian subsidiary, Quicksilver Resources Canada Inc. ("QRCI") located in Calgary, Alberta. The Company also had significant reserves and operations in Michigan, Indiana and Kentucky which were divested in 2007.

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 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 manages a portion of the operating risk relating to natural gas and crude oil price volatility through hedging and fixed-price contracts.

2. SIGNIFICANT ACCOUNTING POLICIES

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.

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 under the equity method of accounting 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 require consolidation of the entities. The Company's share of the results from these entities are included as a component of operating income as operations of the entities are necessary for the Company to process and deliver natural gas from certain of its properties. The Company also consolidates its share of oil and gas joint ventures.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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 revenues 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 revenues 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.

Reclassifications

Certain amounts in prior years' financial statements have been reclassified to conform to the 2007 presentation.

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 2007, 2006 and 2005, one purchaser accounted for approximately 13%, 10% and 10%, respectively, of the Company's total consolidated natural gas, NGL and crude oil sales.

Hedging and Derivatives

The Company enters into financial derivative instruments to hedge price risk for its natural gas, NGL and crude oil sales and interest rate risk. These instruments are accounted for in accordance with Statements of Financial Accounting Standards ("SFAS") No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities*, which amended SFAS No. 133 (see Note 5). The Company does not enter into financial derivatives for trading or speculative purposes.

All derivatives are recorded on the balance sheet as either an asset or liability measured at fair value. Effective portions of gains and losses on derivatives instruments that qualify as hedges are deferred in other comprehensive income and recognized in revenues 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 income or expense in the period in which the hedged transaction is recognized. Fair value is determined by reference to published future market prices, interest rates or confirmed by a counterparty. Ineffective portions of hedges, if any, are recognized currently as a component of other revenue.

Until December 2007, the Company's long-term contract (the "Michigan Sales Contract") for 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 SFAS No. 133. In December 2007, the Company determined it would no longer deliver a portion of its natural gas production to supply the contractual volumes. At that time the Company recognized a loss of $63.5 million for the remainder of the Michigan Sales Contract which reflected that contract's fair value at the date of determination.

Until May 2007, we 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. In May 2007, we ceased delivering natural gas pursuant to the CMS Contract as a result of the judgment entered by the court in the CMS lawsuit. Since the judgment was appealed by CMS, we must post monthly appellate bonds securing the difference between the $2.47 floor price and the market price of natural gas that would have otherwise been delivered under the CMS Contract. At December 31, 2007, the aggregate appellate bonds were $7.7 million. After receiving the judgment in May 2007, the contract was no longer recognized as a normal sales contract under SFAS No. 133.

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 as the operations of the affiliates are associated with processing and transportation of the Company's natural gas production or are otherwise conducting their operations in the same industry as the Company.

The Company accounts for it investment in BreitBurn Energy Partners L.P. ("BBEP") using the equity method of accounting. The Company reviews its investment for impairment whenever events or circumstances indicate that the investment's carrying amount may not be recoverable. The Company will record its portion of BBEP's earnings during the quarter in which their financial statements become publicly available. Accordingly, the accompanying consolidated financial statements do not reflect any equity earnings for BBEP during the quarter ended December 31, 2007.

Property, Plant, and Equipment

The Company follows the full cost method of accounting for oil and gas properties. Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties, including costs of undeveloped leasehold, geological and geophysical expenses and dry holes are capitalized. 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 as determined by independent petroleum engineers. Excluded from amounts subject to depletion are costs associated with unevaluated properties. NGL and crude oil are converted to equivalent units based upon the relative energy content, which is six thousand cubic feet of natural gas to one barrel of crude oil.

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 revenues, 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. Such limitations are imposed separately for the U.S. and Canadian cost centers.

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

Revenue Recognition

Revenues are recognized when title to the products transfer to the purchaser. The Company follows the "sales method" of accounting 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, 2007 and 2006, 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 that will be in effect in years in which the temporary differences are expected to reverse. QRCI computes taxes at rates in effect in Canada. U.S. deferred tax liabilities are not recognized on profits that are expected to be permanently reinvested by QRCI 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.

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.

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

QRCI 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, stock warrants and outstanding convertible securities.

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. No outstanding options were excluded from the diluted net income per share calculation for any of the years presented.

	Years Ended December 31,		
	2007	2006	2005
	(In thousands, except per share data)		
Income from continuing operations	$479,378	$ 93,719	$ 87,272
Income from discontinued operations, net of income taxes	—	—	162
Net income	479,378	93,719	87,434
Impact of assumed conversions — interest on 1.875% convertible debentures, net of income taxes	1,901	1,901	1,901
Income available to stockholders assuming conversion of convertible debentures	$481,279	$ 95,620	$ 89,335
Weighted average common shares — basic	155,475	153,413	151,431
Effect of dilutive securities:			
Employee stock options	1,326	2,220	3,438
Employee stock awards	1,412	817	227
Contingently convertible debentures	9,816	9,816	9,816
Weighted average common shares — diluted	168,029	166,266	164,912
Basic earnings per share:			
Continuing operations	$ 3.08	$ 0.61	$ 0.58
Discontinued operations, net of income taxes	—	—	—
Total	$ 3.08	$ 0.61	$ 0.58
Diluted earnings per share:			
Continuing operations	$ 2.86	$ 0.58	$ 0.54
Discontinued operations, net of income taxes	—	—	—
Total	$ 2.86	$ 0.58	$ 0.54

Recently Issued Accounting Standards

- *Pronouncements Implemented*

Adoption of SFAS No. 123 (revised 2004) — In December 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123 (revised 2004), Share-Based Payment ("SFAS No. 123(R)"). This statement requires the cost resulting from all stock-based transactions be recognized in the financial statements at their fair value on the grant date. We adopted SFAS 123(R) on January 1, 2006. The Company previously accounted for stock awards under the recognition and measurement principles of APB No. 25, Accounting for Stock Issued to Employees, and related Interpretations. Prior to SFAS 123(R) adoption, stock-based employee compensation expense for restricted stock and stock unit grants was reflected in net income, but no compensation expense was recognized for options granted with an exercise price equal to the market value of the underlying common stock on the date of grant.

The Company adopted SFAS No. 123(R) using the modified prospective application method described in the statement. Under the modified prospective application method, the Company applied the standard to new awards and to awards modified, repurchased, or cancelled after January 1, 2006. Additionally, compensation cost for the unvested portion of stock option awards outstanding as of January 1, 2006 has been recognized as compensation expense as the underlying service is rendered after January 1, 2006. The compensation cost for unvested stock option awards granted before adoption of SFAS 123(R) has been attributed to periods beginning January 1, 2006 using the attribution method that was used under SFAS 123. At January 1, 2006, the Company had total compensation cost of $1.1 million related to unvested stock options with a weighted average remaining vesting period of 1.5 years. During 2006, adoption of the statement reduced income by $0.7 million and income from continuing operations and net income by $0.6 million in 2006. The adoption had no effect on cash flows from operating activities or financing activities. Basic and diluted earnings per share for 2006 were each $0.01 lower as a result of SFAS No. 123(R) adoption. At December 31, 2007, unrecognized compensation cost of $0.1 million remains for the unvested portion of stock options awarded prior to 2006.

At January 1, 2006, the Company had total compensation cost of $3.3 million related to unvested restricted stock and stock unit awards. Additionally, restricted stock and stock units granted in 2007 and 2006 had total compensation cost of $13.8 million and $18.3 million, respectively at the time of grant. During 2007, 2006 and 2005, the Company recognized $11.0 million, $5.8 million and $1.7 million of expense, respectively, for vesting of restricted stock and stock units. Total unvested compensation cost was $15.2 million at December 31, 2007 with a weighted average remaining vesting period of 1.0 years.

The following table reflects pro forma net income and the associated earnings per share for 2005 as if the Company had applied the fair value recognition provisions of SFAS No. 123(R).

For the Year Ended December 31, 2005
(In thousands, except per share data)

Net income	$ 87,434
Deduct: Total stock-based compensation expense determined under fair value-based method for stock option awards, net of related income tax benefit	(11,359)
Pro forma net income	76,075
Impact of assumed conversions — 1.875% convertible debentures, net of income taxes	1,901
Pro forma net income available to stockholders assuming conversion of convertible debentures	$ 77,976
As reported	
Basic earnings per share	$ 0.58
Diluted earnings per share	$ 0.54
Pro forma	
Basic earnings per share	$ 0.50
Diluted earnings per share	$ 0.47

Adoption of Interpretation No. 48 — In June 2006, FASB issued Interpretation No. 48 ("FIN 48"), Accounting for Uncertainty in Income Taxes — An Interpretation of FASB Statement No. 109. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. This Interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This Interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. In connection with adopting FIN 48, on January 1, 2007, 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. This reduction in retained earnings was offset against the Company's net operating loss carryforwards in the deferred federal income tax liability account. As of January 1, 2007, the Company's unrecognized tax benefits totaled $0.3 million. The Company's unrecognized tax benefits at December 31, 2007 were $10.0 million. Interest and penalties recognized as interest expense in 2007 were $0.6 million.

- *Pronouncements Not Yet Implemented*

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 in generally accepted accounting principles ("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 will change current practice. The Company adopted SFAS No. 157 on January 1, 2008, however its adoption had no material impact on the Company's financial position, results of operations or cash flows.

On April 30, 2007, the FASB issued FASB Staff Position ("FSP") No. 39-1, *Amendment of FASB Interpretation No. 39.* The FSP amends paragraph 3 of FIN 39 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 that have been offset in accordance with that paragraph. The Company adopted FSP No. 39-1 on January 1, 2008 employing retrospective representation for all periods, but its adoption had no material impact on the Company's financial position, results of operations or cash flows.

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. It provides entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. The Company adopted SFAS No. 159 on January 1, 2008, however its adoption had no material impact on the Company's financial position, results of operations or cash flows.

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 separately from the acquisition. The Statement will apply to any acquisition completed by us on or after January 1, 2009, with early application not allowed.

SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB No. 51* was issued in December 2007. The Statement amends ARB 51 to establish 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 equity in the consolidated financial statements. 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. This Statement is effective for the Company beginning January 1, 2009, although we are still determining the extent, if any, this adoption will have on our financial statements in addition to reclassifying our noncontrolling interests/minority interests into equity.

3. QUICKSILVER GAS SERVICES LP

On August 10, 2007, the Company's majority-owned subsidiary, Quicksilver Gas Services LP ("KGS"), completed its underwritten initial public offering ("IPO") using the ticker symbol "KGS." KGS, a limited partnership engaged in the business of gathering and processing natural gas produced from the Barnett Shale formation in the Fort Worth Basin in North Texas, 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 these IPO-related transactions, KGS' ownership is summarized in the following table:

	Ownership		
	Quicksilver	Non-Quicksilver	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 limited partner interests	71.0%	27.1%	98.1%
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. Generally, the subordination period will end when either:

1. KGS has earned and paid at least $0.30 per quarter on each outstanding common unit, subordinated unit and general partner unit for any three consecutive four-quarter periods ending on or after June 30, 2010; or

2. KGS has earned and paid at least $0.45 per quarter on each outstanding common unit, subordinated unit and general partner unit for any consecutive four quarters.

During the fourth quarter of 2007, KGS paid a distribution of $0.1675 per unit, which represented a pro rata portion of a $0.30 per unit quarterly distribution for the post-IPO portion of KGS' third quarter of 2007.

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. Quicksilver has deferred a gain of approximately $79 million related to the IPO that will be recognized in the consolidated income statement when the subordination period terminates. The Company includes the results of operations and financial position of KGS in the consolidated financial statements of Quicksilver, and recognizes the unowned portion of KGS' results of operations as a component of minority interest expense.

4. DIVESTITURE OF NORTHEAST OPERATIONS

On September 11, 2007, Quicksilver signed a definitive 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. The BreitBurn Transaction closed on November 1, 2007 for total consideration of $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. Subsequent to the closing, the Company used $654 million of proceeds from the BreitBurn Transaction to repay all U.S. borrowings outstanding in 2007 under its senior secured credit facility. Under the terms of the transaction, the Company is prohibited from selling any of the acquired units within one year of closing and is prohibited from selling more than 50% of the acquired units within 18 months of closing.

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 will be recognized approximately 60% in 2007, 20% in 2008 and 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 amounts to be recognized during 2008 and 2009 are attributable to the services to be rendered by the affected employees over these periods and are payable only in the event of continued service to BreitBurn.

A portion of the Company's hedging program that was designated as applicable 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 signing of the BreitBurn agreement, 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 is included as an increase to other revenue in the 2007 consolidated statement 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 is considered to have a "continuing interest" in the assets and subsidiaries sold in the BreitBurn Transaction as the Company owns approximately 32% of the BBEP common units. As a result, 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. 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. Should the Company sell a portion of its BBEP units, a pro rata portion of the deferred gain attributable to the sold units would be recognized.

In completing the BreitBurn Transaction, the Company utilized certain investment banking services. Approximately $2 million of expense related to such services is included in general and administrative expense during the quarter ended September 30, 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.

5. HEDGING AND DERIVATIVES

The Company hedges a portion of its production revenue using various financial derivatives. All derivatives are evaluated using the hedge criteria established under SFAS Nos. 133 and 138. If hedge criteria are met, the change in a derivative's fair value (for a cash flow hedge) is deferred in stockholders' equity as a component of accumulated other comprehensive income. These deferred gains and losses are recognized into income in the period in which the hedged transaction is recognized in revenues to the extent the hedge is effective. The ineffective portions of hedges are recognized currently in earnings.

In December 2007, the Company determined it would no longer deliver a portion of its natural gas production to supply the contractual volumes under its Michigan Sales Contract. At that time the Company recognized a loss of $63.5 million for the fair value of the remaining duration of the contract. In January 2008, the Company entered into a fixed-price natural gas swap covering all remaining volumes for the remaining contract period, January 2008 through March 2009.

The change in carrying value of the Company's derivatives, firm sale and purchase commitments accounted for as hedges in the Company's balance sheet since December 31, 2006 resulted from the decrease in market prices for natural gas and crude oil and the recognition of the Michigan Sales Contract. The change in fair value of all cash flow hedges was reflected in accumulated other comprehensive income, net of deferred tax effects. All derivative assets and liabilities reflected represent the estimated fair value of contract settlements scheduled to occur over each contract period remaining based on market prices for natural gas, NGL and crude oil as of the balance sheet date. These amounts are not due and payable until the monthly period in which the related underlying hedged gas, NGL or oil sales transaction occurs, with settlement usually occurring within 25 to 60 days thereafter.

The estimated fair values of all derivatives and the associated fixed-price firm sale commitments of the Company as of December 31, 2007 and 2006 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.

	As of December 31, 2007	As of December 31, 2006
	(In thousands)	
Derivative assets:		
Fixed-price natural gas sales contracts	$ —	$ 53
Natural gas basis swaps	—	159
Crude oil collars	—	689
Natural gas fixed-price swaps	4,666	1,009
Natural gas collars	10,491	65,982
	$15,157	$67,892
Derivative liabilities:		
Natural gas basis swaps	$ 1,224	$ —
Natural gas financial collars	1,625	159
Floating price natural gas financial swaps	—	53
Crude oil financial collars	6,517	—
NGL fixed-price swaps	11,294	—
Fixed-price natural gas sales contracts(1)	63,777	—
	$84,437	$ 212

(1) Includes $63.5 million for the Michigan Sales Contract at December 31, 2007.

The fair value of all derivative instruments listed above was estimated based on market prices of natural gas, NGL and crude oil for the periods covered by the derivatives and the value confirmed by a counterparty. Estimates were determined by applying the net differential between the prices in each derivative and market prices for future periods, as adjusted for estimated basis, to the volumes stipulated in each contract to arrive at an estimated future value. This estimated future value was discounted on each contract at rates commensurate with federal treasury instruments with similar contractual lives. Hedge derivative assets and liabilities of $10.8 million and $14.6 million, respectively have been classified as current at December 31, 2007 based on the maturity of the derivative instruments, resulting in $3.1 million of after-tax losses to be reclassified from accumulated other comprehensive income in 2008.

6. FINANCIAL INSTRUMENTS

The Company has established policies and procedures for managing risk within its organization, including internal controls. The level of risk assumed by the Company is based on its objectives and capacity to manage risk.

Quicksilver's primary risk exposure is related to commodity prices for its production. The Company has mitigated the downside risk of adverse price movements through the use of swaps, futures and forward contracts; however in doing so, it has also limited future gains from favorable price movements.

Commodity Price Risk

The Company regularly enters into financial derivative contracts to hedge its exposure to commodity price risk associated with anticipated future natural gas, NGL and crude oil production. These contracts can include derivatives with price ceilings and floors, no-cost collars and fixed-price swaps.

In addition to financial derivatives, the Company also previously entered into two natural gas supply contracts. Through December 2007, Quicksilver sold approximately 25 MMcfd of owned or controlled natural gas under the Michigan Sales Contract. In December 2007, the Company determined it would no longer deliver a portion of its natural gas production to supply the contractual volumes under the Michigan Sales

Contract. At that time the Company recognized a loss of $63.5 million for the fair value of the Michigan Sales Contract through the end of its term in March 2009. In January 2008, the Company entered into a fixed-price natural gas swap covering all remaining volumes for the remaining contract period, which served to lock in the amount of our obligation under the Michigan Sales Contract.

Until May 2007, we also had another long-term contract (the "CMS Contract") for delivery of 10MMcfd 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. In May 2007, we ceased delivering natural gas pursuant to the CMS Contract as a result of the judgment entered by the court in the CMS lawsuit. Since the judgment was appealed by CMS, we must post monthly appellate bonds securing the difference between the $2.47 floor price and the market price of natural gas that would have otherwise been delivered under the CMS Contract. At December 31, 2007, the aggregate appellate bonds were $7.7 million. After receiving the judgment in May 2007, the contract was no longer recognized as a normal sales contract under SFAS No. 133.

Natural gas price collars and swaps have been put in place to hedge 2008 anticipated production of approximately 65 MMcfd and 40 MMcfd, respectively. Additionally, the Company has used price collar agreements to hedge approximately 3,000 Bbld and 1,000 Bbld of its anticipated NGL and crude oil production, respectively, in 2008. Anticipated natural gas production of approximately 60 MMcfd has been hedged for 2009 using price collars. These financial derivative contracts allow the Company to benefit from significant predictability of its natural gas and crude oil revenues, with approximately 50% of its expected 2008 production covered by such contracts.

The following table summarizes the Company's open derivative positions as of December 31, 2007 related to its natural gas, NGL and crude oil production.

Product	Type	Contract Period	Volume	Weighted Avg Price Per Mcf or Bbl	Fair Value
		(In thousands)			
Gas	Swap	Jan 2008-Dec 2008	25,000 Mcfd	$ 8.13	$ 2,893
Gas	Swap	Jan 2008-Dec 2008	7,500 Mcfd	8.13	868
Gas	Swap	Jan 2008-Dec 2008	5,000 Mcfd	8.14	597
Gas	Swap	Jan 2008-Dec 2008	2,500 Mcfd	8.15	307
Gas	Collar	Jan 2008-Mar 2008	5,000 Mcfd	7.50- 8.90	149
Gas	Collar	Jan 2008-Mar 2008	15,000 Mcfd	7.50- 8.70	422
Gas	Collar	Jan 2008-Mar 2008	10,000 Mcfd	8.00-15.65	735
Gas	Collar	Jan 2008-Mar 2008	10,000 Mcfd	8.00-15.00	700
Gas	Collar	Jan 2008-Mar 2008	10,000 Mcfd	9.00-12.00	1,502
Gas	Collar	Jan 2008-Mar 2008	10,000 Mcfd	9.00-12.05	1,508
Gas	Collar	Jan 2008-Dec 2008	20,000 Mcfd	7.50- 9.15	1,361
Gas	Collar	Apr 2008-Mar 2009	20,000 Mcfd	7.50- 9.35	(31)
Gas	Collar	Apr 2008-Mar 2009	20,000 Mcfd	8.00-10.20	3,034
Gas	Collar	Jan 2009-Dec 2009	20,000 Mcfd	7.50- 9.34	(1,594)
Gas	Collar	Jan 2009-Dec 2009	20,000 Mcfd	7.75-10.20	726
Gas	Collar	Jan 2009-Dec 2009	10,000 Mcfd	7.75-10.26	354
Gas	Basis	Jan 2008-Dec 2008	10,000 Mcfd		(612)
Gas	Basis	Jan 2008-Dec 2008	10,000 Mcfd		(612)
Gas	Sale	Jan 2008-Mar 2009(1)	25,000 Mcfd	2.49	(63,520)
NGL	Swap	Jan 2008-Dec 2008	1,000 Bbld	39.58	(5,380)
NGL	Swap	Jan 2008-Dec 2008	2,000 Bbld	45.94	(5,914)
Oil	Collar	Jan 2008-Dec 2008	500 Bbld	65.00-73.90	(3,538)
Oil	Collar	Jan 2008-Dec 2008	500 Bbld	65.00-77.45	(2,980)
				Total	$(69,025)

(1) Represents the Michigan Sales Contract

The Company's financial hedging program may result in realized prices that vary from actual prices that the Company receives from the sale of natural gas, NGL and crude oil. As a result of the settlements of derivative contracts, revenues from production in 2007, 2006 and 2005 were $51.5 million and $15.5 million higher and $41.8 million lower, respectively, than if the hedging programs had not been in effect.

Exclusive of recognition of the Michigan Sales Contract, hedge ineffectiveness resulted in $0.2 million of net gains, $0.1 million of net losses and $0.1 million of net gains in 2007, 2006 and 2005, respectively.

The fair values of fixed-price and floating-price natural gas, NGL and crude oil derivatives and associated firm commitments as of December 31, 2007 and 2006 were estimated based on market prices of natural gas, NGL and crude oil for the periods covered by the contracts and the value confirmed by a counterparty. Estimates were determined by applying the net differential between the prices in each contract and market prices for future periods, as adjusted for estimated basis, to the volumes stipulated in each contract to arrive at an estimated future value. This estimated future value was discounted on each contract at rates commensurate with federal treasury instruments with similar contractual lives.

Interest Rate Risk

The Company is exposed to risk associated with interest rates paid on its debt instruments. The Company manages the risk by balancing its debt outstanding between instruments with fixed and variable interest rates. If necessary, the Company will enter into interest rate swaps to maintain an appropriate balance between fixed and variable interest rates.

Credit Risk

Credit risk is the risk of loss as a result of non-performance by counterparties of their contractual obligations. We sell a portion of our natural gas production directly under long-term contracts with the remainder of our natural gas and crude oil production sold at spot or short-term contract prices. All our production is sold to large trading companies and energy marketing companies, refineries and other users of petroleum products. We also enter into hedge derivatives with financial counterparties. We monitor 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 our established policy. Each customer and/or counterparty is reviewed as to credit worthiness prior to the extension of credit and on a regular basis thereafter.

While Quicksilver follows its credit policies at the time it enters into sales contracts, the credit worthiness of counterparties could change over time. The credit rating of the parent company of the counterparty to the Michigan Sales Contract was downgraded in early 2003 and remains below the credit ratings required for the extension of credit to new customers.

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 management of credit risk. 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.

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 the years ended December 31, 2007 and 2005, non-functional currency transactions resulted in losses of $0.8 million and $0.1 million, respectively, reported in the statements of income for those years.

7. ACCOUNTS RECEIVABLE

Accounts receivable consist of the following:

	As of December 31,	
	2007	2006
	(In thousands)	
Accrued production receivables	$51,429	$47,036
Joint interest receivables	26,026	29,155
Accrued taxes receivable	9,804	—
Other receivables	3,089	1,443
Allowance for doubtful accounts	(104)	(1,113)
	$90,244	$76,521

8. OTHER CURRENT ASSETS

Other current assets consist of the following:

	As of December 31,	
	2007	2006
	(In thousands)	
Inventory and supplies	$31,980	$22,593
Prepaid drilling rentals	4,457	1,000
Deposits	2,134	—
Other prepaid expenses	3,618	1,483
	$42,189	$25,076

9. INVESTMENT IN BREITBURN ENERGY PARTNERS L.P.

The Company received common units of BBEP, a publicly traded limited partnership, as part of the BreitBurn Transaction which closed on November 1, 2007 (see note 4). At December 31, 2007, the Company held approximately 32% of the BBEP common units outstanding.

The Company accounts for its investment in BBEP units using the equity method, utilizing a one quarter lag from BBEP's publicly available information. BBEP is primarily engaged in natural gas, NGL and crude oil production in the U.S.

Summarized financial information (unaudited) for BBEP is as follows:

	As of September 30, 2007
	(In thousands)
Current assets	$ 35,844
Property, plant and equipment	414,063
Other assets	41,594
Current liabilities	42,909
Long-term debt	73,691
Other non-current liabilities	19,642
Partners' equity	355,259

At December 31, 2007, the Company's investment balance for its BBEP common units was $420 million inclusive of the $294 million gain deferred from the BreitBurn Transaction. The market value of the Company's BBEP common units was $617 million, or $28.90 per common unit, at December 31, 2007.

10. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consist of the following:

	As of December 31, 2007	As of December 31, 2006
	(In thousands)	
Oil and gas properties		
Subject to depletion	$1,811,295	$1,560,459
Unevaluated costs	215,228	191,665
Accumulated depletion	(262,123)	(308,065)
Net oil and gas properties	1,764,400	1,444,059
Other plant and equipment		
Pipelines and processing facilities	379,869	225,771
General properties	32,966	17,183
Construction in progress	—	31,613
Accumulated depreciation	(34,889)	(39,346)
Net other property and equipment	377,946	235,221
Property, plant and equipment, net of accumulated depletion and depreciation	$2,142,346	$1,679,280

Unevaluated Natural Gas and Crude Oil Properties Excluded From 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 excluded from natural gas and crude oil properties being amortized at December 31, 2007 and 2006 and the year in which they were incurred as follows:

	December 31, 2007 Costs Incurred During					December 31, 2006 Costs Incurred During				
	2007	2006	2005	Prior	Total	2006	2005	2004	Prior	Total
	(In thousands)					(In thousands)				
Acquisition costs	$71,835	$25,357	$39,810	$37,834	$174,836	$46,512	$42,030	$34,994	$28,181	$151,717
Exploration costs	20,334	20,058	—	—	40,392	23,569	7,563	8,658	158	39,948
Total	$92,169	$45,415	$39,810	$37,834	$215,228	$70,081	$49,593	$43,652	$28,339	$191,665

A portion of the Company's recorded value of unevaluated property costs was identified with the Northeast Operations divestiture. Accordingly, approximately $11.6 million of such costs were relieved in recognizing the BreitBurn transaction.

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. As of December 31, 2007, unevaluated costs of $163.3 million and $51.9 million were related to the Company's Texas and Canadian projects, respectively. These costs will be transferred into the amortization base as the undeveloped projects and areas are evaluated. The Company anticipates that the majority of the activities associated with its unevaluated exploration costs should be completed during the next two to three years. Unevaluated acquisition costs will require an estimated eight to ten years of exploration and development activity before evaluation is complete.

Capitalized Costs

Capitalized overhead costs that directly relate to exploration and development activities were $7.0 million, $3.2 million and $5.3 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Depletion per Mcfe was $1.28, $1.07 and $0.91 for the years ended December 31, 2007, 2006 and 2005, respectively.

11. OTHER ASSETS

Other assets consist of the following:

	As of December 31,	
	2007	2006
	(In thousands)	
Deferred financing costs	$21,159	$23,532
Less accumulated amortization	(3,044)	(7,946)
Net deferred financing costs	18,115	15,586
Deferred compensation costs	1,003	3,003
Deposits	2,312	577
Other	1,144	2,315
	$22,574	$21,481

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

12. ACCRUED LIABILITIES

Accrued liabilities consist of the following:

	As of December 31,	
	2007	2006
	(In thousands)	
Accrued capital expenditures	$11,417	$33,959
Accrued operating expenses	14,745	7,527
Accrued product purchases	9,784	2,783
Revenue payable	6,692	6,174
Interest payable	7,402	7,494
Accrued production and property taxes	3,301	1,630
Prepayments from partners	732	6,642
Environmental liabilities	262	749
Other	646	150
	$54,981	$67,108

13. LONG-TERM DEBT

Long-term debt consists of the following:

	As of December 31, 2007	2006
	(In thousands)	
Senior secured credit facility	$310,710	$421,123
Senior subordinated notes	350,000	350,000
Convertible debentures, net of unamortized discount of $1,893 and $2,006	148,107	147,994
KGS Credit Agreement	5,000	—
Other loans	34	400
Total debt	813,851	919,517
Less current maturities	(34)	(400)
Long-term debt	$813,817	$919,117

Maturities are as follows, in thousands of dollars:

2008	$ 34
2009	—
2010	—
2011	—
2012	315,710
Thereafter	500,000
	$815,744

On February 9, 2007, the Company amended its senior secured revolving credit facility to extend its maturity 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. The initial borrowing base was equal to $850 million, but was subsequently increased to $1.1 billion on September 11, 2007. The borrowing base is subject to annual redeterminations and certain other redeterminations. The lenders have agreed to $1.2 billion of revolving credit commitments and the Company has an option to increase the facility to $1.45 billion with consent of the lenders. The lenders' commitments under the facility are allocated between U.S. and Canadian funds, with the U.S. currency available for borrowing by the Company and either U.S. or Canadian currency available for borrowing by QRCI. The facility allows the Company to extend the maturity up to two additional years with requisite lender consent. 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, QRCI's, 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.

The loan agreements for the credit facility prohibit the declaration or payment of dividends by the Company and contain certain financial covenants, which, among other things, require the maintenance of a minimum current ratio and a minimum earnings (before interest, taxes, depreciation, depletion and amortization, non-cash income and expense, and exploration costs) to interest expense ratio. In October 2007, the agents and lenders under the Company's senior secured revolving credit facility consented to the BreitBurn Transaction. As a condition to such consent, among other things, the parties agreed to a reduction in the borrowing base from $1.1 billion to $750 million effective upon consummation of the BreitBurn Transaction. Following the completion of the BreitBurn Transaction, we used $654 million of the proceeds from the divestiture of our Northeast Operations to repay outstanding U.S. borrowings. The Company also agreed to pledge the equity interests in BreitBurn it received as part of the BreitBurn Transaction to secure its and

QRCI's obligations under the credit facility. At December 31, 2007, the Company was in compliance with all covenants and had approximately $438 million available under the senior secured revolving credit facility.

The Senior Subordinated Notes due 2016 ("Senior Subordinated Notes") were issued by the Company March 16, 2006. The Senior Subordinated Notes are unsecured, senior subordinated obligations of the Company and bear interest at an annual rate of 7% payable semiannually on April 1 and October 1 of each year. The terms and conditions of the Senior Subordinated Notes require the Company to comply with certain covenants, which primarily limit certain activities, including, among other things, levels of indebtedness, restricted payments, payments of dividends, capital stock repurchases, investments, liens, restrictions on restricted subsidiaries to make distributions, affiliate transactions and mergers and consolidations. At December 31, 2007, the Company was in compliance with such covenants. At December 31, 2007, the fair value of the $350 million in principal amount of the Senior Subordinated Notes was $339.9 million.

The convertible subordinated debentures due November 1, 2024 are contingently convertible into shares of Quicksilver's common stock (subject to adjustment). The debentures bear interest at an annual rate of 1.875% payable semi-annually on May 1 and November 1 of each year. 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. As of December 31, 2007, the debentures were convertible into 9,816,256 shares of Quicksilver's common stock. Upon conversion, the Company has the option to deliver in lieu of Quicksilver common stock, cash or a combination of cash and Quicksilver common stock. At December 31, 2007, the fair value of the $150 million in principal amount of contingently convertible debentures was $306.3 million.

Concurrent with its IPO, KGS entered into a five-year $150 million senior secured revolving credit facility ("KGS Credit Agreement"), with options exercisable by KGS to extend the facility for up to two additional years and increase the facility up to $250 million, in each case with consent of the lenders. 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. KGS' interest rate options under the facility include the London InterBank Offered Rate ("LIBOR") and U.S. prime for revolving loans and a specified rate for swingline loans. Each interest rate option includes a margin which increases in specified increments in tandem with an increase in KGS' leverage ratio, in accordance with the KGS Credit Agreement. KGS must maintain certain financial ratios that can limit its borrowing capacity. The KGS Credit Agreement contains certain restrictive covenants which, among other things, require the maintenance (measured quarterly) of a maximum leverage ratio of debt to Consolidated EBITDA (as defined in the Credit Agreement) and a minimum ratio of Consolidated EBITDA to interest expense.

At December 31, 2007, KGS' borrowing capacity was $82.7 million, as limited by the facility's leverage ratio test, of which $5 million was outstanding. The KGS Credit Agreement prohibits the declaration or payment of distributions by KGS if a default then exists or would result from payment of a distribution. KGS was in compliance with all covenants at December 31, 2007.

14. 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 long-lived asset by the same amount as the liability. In periods subsequent to initial measurement, the asset retirement cost is allocated to expense using a systematic method 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 the original estimate of undiscounted cash flows. During the years ended December 31, 2007, 2006 and 2005, accretion expense was recognized and included in depletion, depreciation and accretion expense reported in the consolidated statement of income for the period.

The following table provides a reconciliation of the changes in the estimated asset retirement obligation from January 1, 2006 through December 31, 2007.

	As of December 31,	
	2007	2006
	(In thousands)	
Beginning asset retirement obligations	$ 25,206	$20,965
Additional liability incurred	5,239	5,399
Accretion expense	1,509	1,287
Change in estimates	2,385	30
Sale of properties	(11,564)	(2,439)
Asset retirement costs incurred	(180)	(174)
Loss on settlement of liability	4	158
Currency translation adjustment	1,911	(20)
Ending asset retirement obligations	24,510	25,206
Less current portion	646	148
Long-term asset retirement obligation	$ 23,864	$25,058

15. INCOME TAXES

Deferred income taxes are established for all temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. In addition, deferred tax balances must be adjusted to reflect tax rates expected to be in effect in the years in which the temporary differences are expected to reverse. The Company has accrued no U.S. deferred income taxes on QRCI's undistributed earnings or on the related translation adjustments as the Company expects QRCI's undistributed earnings to be permanently reinvested for use in the development of QRCI's oil and gas reserves.

In May 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 has determined the margin tax is an income tax. The Company has recorded a deferred tax provision of $2.5 million and $1.6 million for the Texas margin tax in 2007 and 2006, 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 and 2006 by the Canadian federal government as well as several provinces. The Company's Canadian deferred income tax balances were revalued to reflect the changes in these tax rates. The Company recorded $4.9 million and $3.8 million of income tax benefits in 2007 and 2006 as a result of the Canadian rate reductions.

During the third quarter of 2006, the Company was notified that IRS audits of one of its subsidiaries were closed for all years prior to its 2000 acquisition by the Company. As a result, the Company reversed a $0.9 million deferred tax by recording a reduction to the otherwise calculated tax provision.

The Company's current and deferred tax positions were significantly impacted by the November 2007 divestiture of the Northeast Operations and the resulting gain. Significant components of the Company's deferred tax assets and liabilities as of December 31, 2007 and 2006 are as follows:

	As of December 31, 2007	As of December 31, 2006
	(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	$ —	$ 21,378
Non-current		
Deferred tax assets		
Deferred tax benefit on derivative contract loss	$ 4,973	$ —
Deferred tax benefit on deferred compensation expense	1,506	2,224
Minority interest	624	—
Deferred tax benefit on cash flow hedge losses	617	—
Net operating loss carry forwards	—	41,220
Other	2,336	219
Total deferred tax assets	10,056	43,663
Deferred tax liabilities		
Property, plant and equipment	375,427	192,921
Deferred tax liability on cash flow hedge gains	—	1,243
Deferred tax liability on convertible debenture interest	8,693	5,750
Other	581	—
Total deferred tax liabilities	384,701	199,914
Net deferred tax liabilities	$374,645	$156,251

The provisions for income taxes for the years ended December 31, 2007, 2006 and 2005 are as follows:

	2007	2006	2005
		(In thousands)	
Current state income tax expense	$ 1,143	$ 11	$ 51
Current U.S. federal income tax expense	45,394	—	(23)
Current non U.S. (Canadian) income tax expense	28	262	462
Total current income tax expense	46,565	273	490
Deferred state income tax expense	2,538	1,600	—
Deferred U.S. federal income tax expense	196,276	27,501	26,312
Deferred non U.S. (Canadian) income tax expense	11,129	8,776	13,900
Total deferred income tax expense	209,943	37,877	40,212
Total income tax expense	$256,508	$38,150	$40,702
Deferred federal income tax expense on discontinued operations	$ —	$ —	$ 86

Reconciliations of the statutory federal income tax rate and the effective tax rate for the years ended December 31, 2007, 2006 and 2005 are as follows:

	2007	2006	2005
U.S. federal statutory tax rate	35.00%	35.00%	35.00%
Permanent differences	0.01%	0.16%	0.11%
State income taxes net of federal deduction	0.33%	0.80%	0.03%
FIN 48 recognition	1.17%	—	—
Foreign income taxes	(1.69%)	(6.29%)	(3.36%)
Other	0.04%	(0.74%)	0.02%
Effective income tax rate	34.86%	28.93%	31.80%

During 2007 and 2005, the Company recognized income tax benefits of $2.8 million and $6.5 million, respectively as increases to additional paid in capital.

Included in deferred tax assets at January 1, 2007 were net operating losses of approximately $118 million that were used to reduce U.S. taxable income in 2007. The net operating losses were to expire in 2008 through 2027. These net operating losses had not been 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 tax carry forwards prior to their expirations. However, under Internal Revenue Code Section 382, a change of ownership was deemed to have occurred for our predecessor, MSR Exploration Ltd. ("MSR") in 1998. Due to the limitations imposed by Section 382, a portion of MSR's net operating losses could not be utilized and were not included in deferred tax assets.

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 the Scientific Research and Experimental Development ("SRED") for Canadian taxes in the first quarter of 2007 of $1.1 million. These SRED credits were granted by Revenue Canada in the second quarter of 2007. The following schedule reconciles the total amounts of unrecognized tax benefits for 2007.

	2007 (In thousands)
Unrecognized tax benefits at January 1, 2007	$ 345
Gross amounts of increases in unrecognized tax benefits as a result of tax positions taken during a prior period	1,396
Amount of decreases in unrecognized tax benefits related to settlements with taxing authorities	(1,100)
Gross amounts of increases in unrecognized tax benefits as a result of tax positions taken during the current year	9,356
Unrecognized tax benefits at December 31, 2007	$ 9,997

Approximately $8.6 million of these unrecognized tax benefits, if recognized, would affect the effective tax rate. The total amount of interest and penalties related to these unrecognized tax benefits that was recognized as interest expense for 2007 was $0.6 million. The Company does not expect that the total amounts of unrecognized tax benefits will significantly increase or decrease within the next 12 months.

The Company remains subject to examination by the Internal Revenue Service ("IRS") for the years 2001 through 2006. Currently, the IRS is auditing the Company's 2004 Federal income tax returns. This examination is expected to be completed in 2008.

16. COMMITMENTS AND CONTINGENCIES

The Company leases office buildings and other property under operating leases. Future minimum lease payments, for operating leases with initial non-cancelable lease terms in excess of one year as of December 31, 2007, were as follows, in thousands:

2008	$4,190
2009	3,756
2010	1,163
2011	363
2012	4
Thereafter	—
	$9,476

Rent expense for operating leases with terms exceeding one month was $5.2 million in 2007, $3.5 million in 2006 and $2.3 million in 2005.

As of December 31, 2007, the Company had approximately $1.6 million in letters of credit outstanding related to various state and federal bonding requirements. In addition, the Company had approximately $13.2 million in surety bonds issued to fulfill contractual, legal or regulatory requirements.

The Company has contracts for the use of drilling rigs in its drilling and exploration programs for periods ranging from one to three years at an estimated day rate of $21,500 per day. Each of the contracts requires payment of the specified day rate for the entire lease term of each contract regardless of the Company's utilization of the drilling rigs. As of December 31, 2007, commitments under these contracts, in thousands, were as follows:

2008	$29,109
2009	29,070
2010	2,753
	$60,932

The Company has entered into firm transportation contracts with pipelines. Under the contracts, we are obligated to transport minimum daily gas volumes, as calculated on a monthly basis, or pay for any 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. As of December 31, 2007, commitments under these contracts, in thousands, were as follows:

2008	$ 2,940
2009	8,987
2010	10,494
2011	10,494
2012	10,523
Thereafter	59,631
	$103,069

In October 2007, KGS entered into an agreement to engineer, design, construct, install, and test a 125 MMcfd cryogenic gas processing and liquid hydrocarbon recovery facility in the Fort Worth Basin. KGS also entered into an agreement to provide natural gas compression equipment for the facility. Progress payments will be due upon completion of established milestones related to the construction of the natural gas processing facility. Commitments under these contracts were $65.5 million at December 31, 2007. The Company estimates payments will be $42.0 million and 23.9 million in 2008 and 2009, respectively. The gas processing facility is estimated to be placed into operation during the first quarter of 2009.

On October 13, 2006, the Company filed suit in the 342nd Judicial District Court in Tarrant County, Texas against Eagle Drilling, LLC and Eagle Domestic Drilling Operations, LLC (together "Eagle") regarding three contracts for drilling rigs in which the Company alleges 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. Subsequently, on January 19, 2007, Eagle Domestic Drilling Operations, LLC and its parent, Blast Energy Services, Inc. filed for Chapter 11 bankruptcy in the United States Bankruptcy Court for the Southern District of Texas, Houston Division. 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. On September 17, 2007, Eagle Drilling, LLC, and Rod and Richard Thornton, sued the Company and P. Jeff Cook, the Company's Executive Vice President Operations, in the District Court of Cleveland County, Oklahoma for approximately $29 million in damages and an unspecified amount of punitive damages resulting from the Company's decision to repudiate the rig contracts mentioned above. Based upon information currently available, the Company believes that the final resolution of this matter will not have a material effect on the Company's financial condition, results of operations, or cash flows.

On November 7, 2001, Quicksilver Resources Inc. filed a lawsuit against CMS Marketing Services and Trading Company ("CMS") in the 236th Judicial District Court of Tarrant County, Texas. The suit alleged that CMS committed fraud when it entered into a 10-year contract with us 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. We sought unspecified damages and rescission of the contract. On May 15, 2007, the Court upheld a jury finding against CMS on the fraudulent inducement claim, rescinded the contract and rendered the contract void beginning May 15, 2007. CMS is appealing the judgment. We have also appealed the Court's judgment because we believe the contract was void from its inception rather than from the date of judgment entry. In May 2007, we ceased delivering natural gas pursuant to the CMS Contract as a result of the judgment entered by the court in the CMS lawsuit. Because the judgment was appealed by CMS we are required to post monthly appellate bonds securing the difference between $2.47 and the market price of natural gas that would have otherwise been delivered under the CMS Contract.

The Company is subject to various possible contingencies, which arise primarily from interpretation of federal and state laws and regulations affecting the natural gas and crude oil industry. Such contingencies include differing interpretations as to the prices at which natural gas and crude oil sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Although management believes it has complied with the various laws and regulations, administrative rulings and interpretations thereof, adjustments could be required as new interpretations and regulations are issued. In addition, production rates, marketing and environmental matters are subject to regulation by various federal and state agencies.

17. 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 in prior years.

Transactions Impacting Minority Interest Prior to KGS IPO

Effective April 1, 2006, the Company contributed its Cowtown gas processing facility to Cowtown Gas Processing Partners LP ("Processing Partners") for a 95% interest in Processing Partners (1% interest as the general partner and 94% as a limited partner) through its wholly-owned subsidiary Cowtown Gas Processing LP. As general partner, the Company receives $15,000 per month for management of Processing Partners. A minority owner initially contributed $1.4 million to Processing Partners for a 5% limited partnership interest in

Processing Partners. The minority owner contributed an additional $1.7 million to Processing Partners to fund capital expenditures in 2006. The minority owner's share of partnership loss in 2006 was $0.1 million.

Also effective April 1, 2006, Quicksilver contributed its Cowtown pipeline assets to Cowtown Pipeline Partners LP ("Pipeline Partners") for a 93% interest in Pipeline Partners (1% as the general partner and 92% as a limited partner) through its wholly-owned subsidiary Cowtown Pipeline LP. As general partner, the Company receives $5,000 per month for management of Pipeline Partners. Two minority owners initially contributed a total of $3.1 million to Pipeline Partners for limited partnership interests totaling 7%. The minority owners contributed an additional $0.9 million to Pipeline Partners to fund capital expenditures in 2006. Minority interest expense for the minority owners' share of partnership income in 2006 was $0.2 million.

18. EMPLOYEE BENEFITS

Quicksilver has a 401(k) retirement plan available to all U.S. employees with 90 days of service and who are at least 21 years of age. Prior to January 1, 2006, the Company made discretionary contributions to the plan. Effective January 1, 2006, the Company's Board of Directors approved amendments to the plan to provide for a Company match of employees' contributions and a fixed annual contribution by the Company in addition to any discretionary contributions by the Company to the plan. Company contributions were $1.6 million, $1.4 million and $0.7 million for the years ended December 31, 2007, 2006 and 2005, respectively.

QRCI, Quicksilver's Canadian subsidiary, has a retirement plan available to all Canadian employees. The plan provides for a match of employees' contributions by QRCI and a fixed annual contribution. Contributions by QRCI were $0.7 million, $0.5 million and $0.3 million for the years ended December 31, 2007, 2006 and 2005, respectively.

The Company maintains a self-funded health benefit plan that covers all eligible U.S. employees of the Company. 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. The claim liability for the total group was $3.0 million, $2.2 million and $1.8 million for the plan years ended June 30, 2007, 2006 and 2005, respectively. The Company purchased aggregate level reinsurance for payment of claims up to one million dollars over the estimated maximum claim liability of $1.9 million for the plan year ending June 30, 2008. Administrative expenses for each of the plan years ended June 30, 2007, 2006 and 2005 were $0.5 million, $0.4 million and $0.4 million, respectively.

19. STOCKHOLDERS' EQUITY

Common Stock, Preferred Stock and Treasury Stock

The Company is authorized to issue 200 million shares of common stock with a par value per share of one cent ($0.01) and 10 million shares of preferred stock with a par value per share of one cent ($0.01). At December 31, 2007, the Company had 158,016,544 shares of common stock outstanding.

The following table shows common share and treasury share activity since January 1, 2005:

	Common Shares Issued	Treasury Shares Held
Opening balance at January 1, 2005	152,935,691	2,568,611
Stock options exercised	1,495,976	—
Restricted stock activity	297,484	2,458
Balance at December 31, 2005	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

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 34% of the Company's common stock at December 31, 2007.

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

On October 4, 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. Upon approval of the 1999 Plan, 3.9 million shares of common stock were reserved for issuance pursuant to grants of 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 3.6 million shares were reserved for issuance pursuant to the 1999 Plan.

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 750,000 shares reserved under the 2004 Plan, which provided for the grant of non-qualified options and restricted stock awards to Quicksilver's non-employee directors.

Under terms of the 1999 Plan and 2004 Plan, retention stock awards and options were granted to officers, employees and non-employee directors at an exercise price not less than 100% of the fair market value on the date of grant. Incentive stock options and non-qualified options may not be exercised more than 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. As a result, shares reserved under the 1999 and 2004 Plans do not reflect the effect of the January 2008 stock split.

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 pursuant to grants of stock options, appreciation rights, restricted shares, restricted stock units, performances shares and performances units and senior executive plan bonuses. Executive officers, other employees, consultants and non-employee directors of the Company or a subsidiary of the Company are eligible to participate in the 2006 Equity Plan. Under the terms of the 2006 Equity Plan, options may be granted at an exercise price that is not less than 100% of the fair market value on the date of grant and may not be exercised more than ten years from the date of grant. At December 31, 2007, 12,959,828 shares (including 31,754 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 fair value of stock options was estimated on the grant date using the Black-Scholes option pricing model with the following weighted average assumptions:

	2007	2006	2005
Wtd avg grant date fair value	N/A	$12.50	$8.84
Wtd avg grant date	N/A	Jan 3, 2006	Jan 14, 2005
Wtd avg risk-free interest rate	N/A	4.35%	4.0%
Expected life (in years)	N/A	10.0	7.0
Wtd avg volatility	N/A	37.3%	38.2%
Expected dividends	N/A	—	—

The following table summarizes the Company's stock option activity for the year ended December 31, 2007.

	Shares	Wtd Avg Exercise Price	Wtd Avg Remaining Contractual Life	Aggregate Intrinsic Value (In thousands)
Outstanding at January 1, 2007	3,378,380	$8.42		
Granted	—	—		
Exercised	(2,257,840)	9.47		
Cancelled	(98,628)	5.51		
Outstanding at December 31, 2007	1,021,912	$7.48	2.1	$23,931
Exercisable at December 31, 2007	611,716	$6.96	2.2	$13,997

The Company estimates that a total of 980,892 stock options will become vested including those options already exercisable. These options have a weighted average exercise price of $6.41 and a weighted average remaining contractual life of 2.1 years.

Compensation expense related to stock options of $0.1 million and $0.7 million was recognized for the years 2007 and 2006, respectively. Cash received from the exercise of stock options totaled $21.4 million, $19.7 million and $2.9 million for the years ended December 31, 2007, 2006 and 2005, respectively. The total intrinsic value of options exercised during the years ended December 31, 2007, 2006 and 2005, was $30.5 million, $26.9 million and $21.8 million, respectively.

Restricted Stock Under All Plans

The following table summarizes the Company's restricted stock and stock unit activity for the year ended December 31, 2007.

	Shares	Wtd Avg Grant Date Fair Value
Outstanding at January 1, 2007	1,023,746	$19.17
Granted	858,462	18.17
Exercised	(312,594)	18.62
Cancelled	(229,492)	18.60
Outstanding at December 31, 2007	1,340,122	$18.76

Compensation expense recognized for restricted stock and stock units during the years 2007, 2006 and 2005 was $11.0 million, $5.8 million and $1.7 million, respectively. As of December 31, 2007, the unrecognized compensation cost related to outstanding unvested restricted stock was $15.2 million, which is expected to be recognized over a weighted average period of one year.

The total fair value of shares vested during the years ended December 31, 2007, 2006 and 2005 was $6.4 million, $2.1 million and $0.6 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. At the time of issuance, the Board of Directors of KGS determines whether the phantom units will be settled in cash or settled in KGS units. For awards payable in cash, KGS amortizes the expense associated with the award over the vesting period. However, the fair value is reassessed at every balance sheet date, such that the vested portion of awards is adjusted to reflect revised fair value via compensation expense. Phantom unit awards payable in units are valued at the closing market price of KGS common units on the date of grant. The unearned compensation is amortized to compensation expense over the vesting period of the phantom award. The following table summarizes information regarding the phantom unit activity:

	Payable in Cash		Payable in Units	
	Shares	Wtd Avg Grant Date Fair Value	Shares	Wtd Avg Grant Date Fair Value
Outstanding at beginning of year	—	$ —	—	$ —
Vested	—	—	—	—
Issued	84,961	21.36	9,833	21.36
Cancelled	—	—	—	—
Outstanding at end of year	84,961	$21.36	9,833	$21.36

KGS recognized compensation expense of approximately $0.1 million during 2007. At December 31, 2007, there is unrecognized compensation of $1.9 million which will be recognized over a weighted average period of 2.6 years.

20. DISCONTINUED DRILLING OPERATIONS

On July 28, 2005, Quicksilver purchased three drilling rigs and other associated assets for $5.6 million. The Company took over drilling operations and began construction of two additional drilling rigs. The Company sold the drilling assets and drilling rigs under construction on September 29, 2005 for $8.2 million. The purchaser of these assets agreed to conduct drilling operations on the Company's Barnett Shale properties, using the acquired rigs at market rates and on other customary contract terms. During the fourth quarter of 2005, Quicksilver received an additional $0.37 million for inventory, furniture and fixtures. The Company's estimated book value for all drilling-related assets sold was $8.2 million. The Company recorded a $0.16 million gain before income tax expense from the sale. During the two-month operating period when the rigs were owned by Quicksilver, revenue earned in drilling operations was $1.9 million and operating income before income taxes was $0.1 million.

21. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The following subsidiaries of Quicksilver are guarantors of Quicksilver's Senior Subordinated Notes issued March 16, 2006: 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. The financial position, results of operations and cash flows of these subsidiaries are included as non-guarantor subsidiaries in the condensed consolidating financial statements presented below, and 2006 and 2005 information has been reclassified to conform to the 2007 presentation.

Condensed Consolidating Balance Sheets

	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

	December 31, 2006				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
			(In thousands)		
ASSETS					
Current assets	$ 165,061	$ 2,851	$326,608	$(323,556)	$ 170,964
Property and equipment	1,043,037	688	635,555	—	1,679,280
Investment in subsidiaries (equity method)	510,548	125,242	4,668	(633,024)	7,434
Other assets	22,397	—	2,837	—	25,234
Total assets	$1,741,043	$128,781	$969,668	$(956,580)	$1,882,912
LIABILITIES AND STOCKHOLDERS EQUITY					
Current liabilities	$ 368,073	$ 189	$154,683	$(323,556)	$ 199,389
Long-term liabilities	797,304	32	303,090	—	1,100,426
Minority interest	—	—	7,431	—	7,431
Stockholders' equity	575,666	128,560	504,464	(633,024)	575,666
Total liabilities and stockholders' equity	$1,741,043	$128,781	$969,668	$(956,580)	$1,882,912

Condensed Consolidating Statements of Income

	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)
Operating income	691,918	(601)	112,264	—	803,581
Equity in net earnings of subsidiaries	76,060	7,407	—	(83,467)	—
Interest expense and other	50,077	(2,418)	20,036	—	67,695
Income tax provision	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
Operating income	85,161	411	88,624	—	174,196
Equity in net earnings of subsidiaries	58,543	—	—	(58,543)	—
Interest expense and other	29,766	—	12,561	—	42,327
Income tax provision	20,219	144	17,787	—	38,150
Net income	$ 93,719	$ 267	$ 58,276	$(58,543)	$ 93,719

	December 31, 2005				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
			(In thousands)		
Revenues	$165,194	$4,894	$144,828	$ (4,468)	$310,448
Operating expenses	111,552	2,900	52,249	(4,468)	162,233
Income from equity affiliates	62	—	852	—	914
Operating income	53,704	1,994	93,431	—	149,129
Equity in net earnings of subsidiaries	61,716	—	—	(61,716)	—
Interest expense and other	14,174	—	6,981	—	21,155
Income tax provision	13,974	698	26,030	—	40,702
Income from continuing operations	87,272	1,296	60,420	(61,716)	87,272
Discontinued operations, net	162	—	—	—	162
Net income	$ 87,434	$1,296	$ 60,420	$(61,716)	$ 87,434

Condensed Consolidating Statements of Cash Flows

	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 and 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 and 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

	December 31, 2005				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
			(In thousands)		
Cash flow provided by operations	$ 53,723	$ 42,230	$ 44,289	$—	$ 140,242
Cash flow used for investing activities	(183,630)	(43,310)	(94,639)	—	(321,579)
Cash flow provided by financing activities	128,469	—	50,493	—	178,962
Effect of exchange rates on cash	—	—	746	—	746
Net increase (decrease) in cash and equivalents	(1,438)	(1,080)	889	—	(1,629)
Cash and equivalents at beginning of period	10,428	1,080	4,439	—	15,947
Cash and equivalents at end of period	$ 8,990	$ —	$ 5,328	$—	$ 14,318

22. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid for interest and income taxes is as follows:

	Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Interest	$69,038	$37,627	$21,446
Income taxes	—	3	888

Other non-cash transactions are as follows:

	Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Noncash changes in working capital related to acquisition of property, plant and equipment — net	$ (41,460)	$(48,238)	$(31,475)
Noncash interest in BreitBurn Energy Partners L.P.	429,618	—	—
Tax benefit recognized on employee stock option exercises	2,755	—	6,536

23. RELATED PARTY TRANSACTIONS

As of December 31, 2007, members of the Darden family, Mercury Exploration Company ("Mercury") and Quicksilver Energy L.P., entities that are owned by members of the Darden family, beneficially owned approximately 34% of the Company's outstanding common stock. Thomas Darden, Glenn Darden and Anne Darden Self are officers and directors of the Company.

Quicksilver and its associated entities paid $2.1 million, $1.4 million and $1.0 million in 2007, 2006 and 2005, respectively, for rent on buildings owned by Pennsylvania Avenue, LP ("PALP", a limited partnership owned by members of the Darden family and Mercury) and WFMG, LP ("WFMG", a limited partnership owned by PALP and unrelated parties.) Rental rates were determined based on comparable rates charged by third parties. In February 2006, the Company entered into an amendment to its lease with PALP to increase the amount of office space covered thereby. In conjunction with this lease amendment, the Company also agreed to sublease a portion of the property it leases to Mercury. At December 31, 2007, the Company had future lease obligations to PALP and WFMG of $3.0 million through 2010.

During 2007 and 2006, the Company paid Regal Jets, LLC (formerly known as Regal Aviation LLC), an unrelated airplane management company, $0.2 million and $0.4 million for use of an airplane owned by Sevens Aviation, LLC, a company owned indirectly by members of the Darden family. Usage rates were determined based on comparable rates charged by third parties.

Payments received in 2007, 2006 and 2005 from Mercury for sublease rentals, employee insurance coverage and administrative services were $0.2 million, $0.1 million and $0.1 million, respectively.

On June 23, 2006, Quicksilver received an assignment from KC7 Ranch Ltd. ("KC7") of an oil and gas lease dated October 25, 2005 from Si Bar, KC Ranch, Ltd. as lessor to KC7 Ranch Ltd. as lessee covering 2,773 acres in exchange for $0.2 million in cash. Under the terms of the assignment of the lease, KC7 is entitled to a 3% overriding royalty interest, pursuant to which KC7 will receive payments from Quicksilver based on any future production of oil or gas from the acreage subject to the lease. On July 7, 2006, KC7 Ranch Ltd. as lessor granted an oil and gas lease to Quicksilver covering 2,773 acres in exchange for a cash payment of $0.3 million. The lease has a three-year primary term and KC7 is entitled to receive a 20% royalty interest pursuant to which it will receive payments from Quicksilver based on any future production of oil or gas from the acreage subject to the lease. Future payments, if any, pursuant to the royalty and overriding royalty interests cannot be estimated at this time. KC7 is a limited partnership in which Quicksilver Energy LP, an entity controlled by members of the Darden family, owns an 80% limited partner interest and maintains additional preferences in distributions of profit from KC7; the other 20% limited partner interest is owned or controlled by Jeff Cook, our Executive Vice President — Operations, individually and as trustee for his two children. KC7's general partner is owned equally by Glenn Darden, Thomas Darden, and Anne Darden Self. The purchase price to acquire the leases and the terms of the leases were determined based on comparable prices and terms paid and granted to third parties with respect to similar leases in the area. The approximate 80% net revenue interest that Quicksilver has in these leases is commensurate with that which Quicksilver has with respect to other leases in the area. Aggregate payments to KC7 in 2007 and 2006 were $0.2 million and $0.7 million, respectively.

24. SEGMENT INFORMATION

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

	Exploration & Production United States	Exploration & Production Canada	Processing & Gathering	Corporate	Elimination	Quicksilver Consolidated
			(In thousands)			
2007						
Revenues	$ 396,768	$158,121	$ 36,081	$ —	$(29,712)	$ 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
2005						
Revenues	$ 210,983	$ 97,744	$ 4,894	$ —	$ (3,173)	$ 310,448
Depletion, depreciation and accretion	34,896	19,089	613	615		55,213
Operating income	104,845	61,992	1,994	(19,702)		149,129
Property, plant and equipment — net	728,223	332,580	49,107	2,092		1,112,002
Property and equipment costs incurred	197,537	118,680	43,708	1,044		360,969

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.

The tables set forth in this note do not include any information for the Company's proportionate share of BBEP's reserves, oil and gas operating results and other information. Our ownership of BBEP units was partial proceeds from the November 1, 2007 divestiture of our Northeast Operations. The most recent information available to the Company regarding BBEP's reserves and other attributes relates to the year ended December 31, 2006, as reported in BBEP's Annual Report on Form 10-K filed with the SEC on April 2, 2007. The footnotes to the tables set forth in this note include certain information regarding what the Company's proportionate interest in BBEP's reserves and other attributes would have been had the Company held its 32% limited partnership interest in BBEP at December 31, 2006. However, BBEP's reserves and other attributes as of December 31, 2006 are not indicative of its reserves and other attributes as of December 31, 2007 for a variety of reasons, including BBEP's acquisition of the Northeast Operations in November 2007. Accordingly, BBEP's reserves and other attributes as of December 31, 2007, and the Company's proportional interest in those reserves and other attributes, are likely to differ materially from BBEP's reserves and other attributes as of December 31, 2006 and a hypothetical 32% proportional interest in such reserves and other attributes.

The changes in proved reserves for the three years ended December 31, 2007 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, 2004	627,676	261,077	888,753	4,187	—	4,187	9,067	—	9,067
Revisions	(7,898)	(21,155)	(29,053)	(1,233)	3	(1,230)	(2,883)	—	(2,883)
Extensions and discoveries	128,038	79,813	207,851	6,884	—	6,884	280	—	280
Purchases in place	236	—	236	5	—	5	4	—	4
Sales in place	(65)	—	(65)	—	—	—	—	—	—
Production	(31,944)	(14,825)	(46,769)	(220)	(3)	(223)	(553)	—	(553)
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	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	(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
Proved developed reserves									
December 31, 2005	593,630	199,859	793,489	5,153	—	5,153	4,986	—	4,986
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

(1) Although the Company did not acquire its 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.

The carrying value of oil and gas producing assets as of December 31, 2007, 2006 and 2005 were as follows:

	United States	Canada (In thousands)	Consolidated
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	$1,070,026	$ 374,033	$1,444,059
2005			
Proved properties	$ 779,661	$ 300,001	$1,079,662
Unevaluated properties	102,206	29,884	132,090
Accumulated DD&A	(210,495)	(32,599)	(243,094)
Net capitalized costs	$ 671,372	$ 297,286	$ 968,658

(1) Although the Company did not acquire its 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.

Capital expenditures for exploration and development activities during each of the three years ended December 31, 2007, were as follows:

	United States	Canada (In thousands)	Consolidated
2007			
Proved acreage	$ —	$ —	$ —
Unproved acreage	17,031	31,448	48,479
Development costs	213,180	53,439	266,619
Exploration costs	511,314	26,122	537,436
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	$433,590	$111,149	$544,739
2005			
Proved acreage	$ 821	$ 1,620	$ 2,441
Unproved acreage	48,419	3,784	52,203
Development costs	24,007	82,388	106,395
Exploration costs	109,148	9,829	118,977
Total	$182,395	$ 97,621	$280,016

(1) Although the Company did not acquire its 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 $12.2 million of capitalized expenditures for exploration and development, all within the United States.

Results of operations from producing activities for the three years ended December 31, 2007, are set forth below:

	United States	Canada (In thousands)	Consolidated
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	$ 92,674	$ 47,084	$139,758
2005			
Natural gas, NGL and crude oil sales	$209,715	$ 96,489	$306,204
Oil & gas production expense	69,609	16,663	86,272
Depletion & amortization expense	30,174	17,347	47,521
	109,932	62,479	172,411
Income tax expense	38,476	21,005	59,481
Results from producing activities	$ 71,456	$ 41,474	$112,930

(1) Although the Company did not acquire its 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.

The Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves ("Standardized Measure") does not purport to present the fair market value of 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 natural gas and crude oil year-end prices were used in the Standardized Measure. These prices were adjusted by field for appropriate regional differentials.

	At December 31,		
	2007	2006	2005
Natural gas — Henry Hub-Spot	$ 6.80	$ 5.64	$10.08
Natural gas — AECO	6.35	5.39	8.41
Crude oil — WTI Cushing	95.98	60.85	61.06

Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over 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, 2007, 2006 and 2005 were as follows:

	United States	Canada	Total
		(In thousands)	
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 — calculated difference	(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 — calculated difference	(1,813,746)	(372,238)	(2,185,984)
Standardized measure of discounted future cash flows relating to proved reserves	$ 1,125,490	$ 360,335	$ 1,485,825
December 31, 2005			
Future revenues	$ 7,387,151	$2,487,289	$ 9,874,440
Future production costs	(1,974,844)	(494,056)	(2,468,900)
Future development costs	(179,141)	(145,303)	(324,444)
Future income taxes	(1,719,136)	(539,167)	(2,258,303)
Future net cash flows	3,514,030	1,308,763	4,822,793
10% discount — calculated difference	(2,283,052)	(715,609)	(2,998,661)
Standardized measure of discounted future cash flows relating to proved reserves	$ 1,230,978	$ 593,154	$ 1,824,132

(1) Although the Company did not acquire its 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.

The primary changes in the standardized measure of discounted future net cash flows for the three years ended December 31, 2007, were as follows:

	Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Net changes in price and production cost	$ 711,962	$(1,236,793)	$ 919,502
Development costs incurred	170,686	78,063	44,399
Revision of estimates	38,547	(94,080)	(29,506)
Changes in estimated future development costs	33,326	42,015	43,939
Purchase and sale of reserves, net	(1,008,566)	(1,977)	824
Extensions and discoveries	1,329,445	661,033	515,810
Net change in income taxes	(293,374)	302,342	(405,724)
Sales of oil and gas net of production costs	(392,116)	(275,745)	(219,932)
Accretion of discount	196,275	260,340	134,428
Timing and other differences	(102,807)	(73,505)	(150,339)
Net increase (decrease)	$ 683,378	$ (338,307)	$ 853,401

26. SELECTED QUARTERLY DATA (UNAUDITED)

	Quarter Ended			
	March 31	June 30	September 30	December 31
	(In thousands, except per share data)			
2007				
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
2006				
Operating revenues	$ 99,650	$ 89,465	$ 99,213	$102,034
Operating income	49,925	39,242	43,841	41,188
Net income	27,535	23,608	22,861	19,715
Basic net earnings per share	$ 0.18	$ 0.15	$ 0.15	$ 0.13
Diluted net earnings per share	0.17	0.14	0.14	0.12

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 a natural gas supply contract with a floor price of $2.49 per Mcf for 25MMcfd for the remaining contract period.

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 Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) 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 under the Exchange Act 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, as appropriate 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, 2007. 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, 2007.

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 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, 2007, 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, 2007, our internal control over financial reporting was effective.

The effectiveness of our internal control over financial reporting as of December 31, 2007, 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 the quarter ended December 31, 2007 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, 2007, 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 — Management's Statement of Responsibilities. 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, 2007, 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, 2007 of the Company and our report dated February 27, 2008 expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding the adoption of Statement of Financial Accounting Standards No. 123 (Revised 2004), *Share Based Payments.*

/s/ DELOITTE & TOUCHE LLP

Fort Worth, Texas
February 27, 2008

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 21, 2008 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 21, 2008 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 21, 2008 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 21, 2008 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 21, 2008 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 21, 2008 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 21, 2008 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 21, 2008 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 May 21, 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 21, 2008 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 21, 2008 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.	
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 23, 2006 (filed as Exhibit 3.1 to the Company's Form 10-Q filed August 4, 2006 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	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 10.3 to the Company's Form 8-K filed May 25, 2007 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).

Exhibit No.	
+ 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. Amended and Restated 2006 Equity Plan (filed as Exhibit 10.1 to the Company's Form 8-K filed May 25, 2007 and included herein by reference).
+ 10.12	Form of Restricted Share Agreement pursuant to the Quicksilver Resources Inc. 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. 2006 Equity Plan (filed as Exhibit 10.3 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.14	Form of Quicksilver Resources Canada Inc. Restricted Stock Unit Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan (filed as Exhibit 10.4 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.15	Form of Incentive Stock Option Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan (filed as Exhibit 10.5 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.16	Form of Non-Qualified Stock Option Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan (filed as Exhibit 10.6 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.17	Form of Non-Employee Director Non-Qualified Stock Option Agreement pursuant to the Quicksilver Resources Inc. 2006 Equity Plan (filed as Exhibit 10.8 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.18	Form of Non-Employee Director Restricted Share Agreement pursuant to the Quicksilver Resources Inc. 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).
+ 10.19	Form of Non-Employee Director Restricted Share Agreement pursuant to the Quicksilver Resources Inc. 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).
+ 10.20	Description of Non-Employee Director Compensation for Quicksilver Resources Inc. (filed as Exhibit 10.6 to the Company's Form 10-Q filed August 9, 2007 and included herein by reference).
+ 10.21	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).
+ 10.22	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).
+ 10.23	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).
+ 10.24	Quicksilver Resources Inc. Change in Control Retention Incentive Plan (filed as Exhibit 10.1 to the Company's Form 8-K filed August 30, 2004 and included herein by reference).

Exhibit No.	
+ 10.25	Quicksilver Resources Inc. Amended and Restated Key Employee Change in Control Retention Incentive Plan (filed as Exhibit 10.1 to the Company's Form 8-K filed August 31, 2006 and included herein by reference).
+ 10.26	Quicksilver Resources Inc. Executive Change in Control Retention Incentive Plan (filed as Exhibit 10.3 to the Company's Form 8-K filed August 30, 2004 and included herein by reference).
+ 10.27	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).
10.28	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).
10.29	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).
10.30	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).
10.31	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.)
+ 10.32	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).
+ 10.33	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).
+ 10.34	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).
+ 10.35	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).
+ 10.36	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.
* 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.

* Filed herewith.

\+ 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: February 27, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, the following persons on behalf of the registrant and in the capacities and on the dates indicated have signed this report below.

Signature	Title	Date
/s/ Thomas F. Darden Thomas F. Darden	Chairman of the Board; Director	February 27, 2008
/s/ Glenn Darden Glenn Darden	President and Chief Executive Officer (Principal Executive Officer); Director	February 27, 2008
/s/ Philip Cook Philip Cook	Senior Vice President — Chief Financial Officer (Principal Financial Officer)	February 27, 2008
/s/ John C. Regan John C. Regan	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)	February 27, 2008
/s/ Anne Darden Self Anne Darden Self	Director	February 27, 2008
/s/ W. Byron Dunn W. Byron Dunn	Director	February 27, 2008
/s/ James A. Hughes James A. Hughes	Director	February 27, 2008
/s/ Steven M. Morris Steven M. Morris	Director	February 27, 2008
/s/ W. Yandell Rogers, III W. Yandell Rogers, III	Director	February 27, 2008
/s/ Mark J. Warner Mark J. Warner	Director	February 27, 2008

QUICKSILVER RESOURCES INC.
2007 Finding and Development Costs
(Unaudited)

The following schedule reflects a reconciliation of 2007 "Finding and Development Costs" to the information required by paragraphs 11 and 21 of Statement of Financial Accounting Standard No. 69. Finding and Development 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 reserve additions for the year.

Dollars in millions, reserves in billions of cubic feet equivalent	
Total exploration, development and acquisition capital expenditures	$ 852.5
SFAS 143 asset retirement obligation additions	5.4
Adjustments:	
Unevaluated costs as of December 31, 2006	191.7
Unevaluated costs as of December 31, 2007	(215.2)
Adjusted capital expenditures related to reserve additions	$ 834.4
Reserve extensions, discoveries, revisions and purchases (Bcfe)	607.7
Finding & development costs ($/mcfe)	$ 1.37

Management believes that providing a measure of finding and development 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 this measure is 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, finding and development 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 2007 Production Replacement Ratio

The production replacement ratio is calculated by dividing the sum of reserve additions from all sources (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	(2,269)
Extensions & discoveries	609,935
Total additions	607,666
Production	77,949
Production replacement	780%

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
D. Wayne Blair
Vice President – Finance
C. Clay Blum
Vice President – Land
Richard C. Buterbaugh
Vice President – Investor Relations & Corporate Planning
MarLu Hiller
Vice President – Treasurer
Stan G. Page
Vice President – US Operations
John C. Regan
Vice President, Controller & Chief Accounting Officer
Anne D. Self
Vice President – Human Resources
Robert N. Wagner
Vice President – Reservoir Engineering

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 21, 2008 at the Petroleum Club, 777 Main Street Fort Worth, Texas.

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

777 West Rosedale Street
Fort Worth, Texas 76104
817.665.5000
www.qrinc.com
NYSE: KWK

END