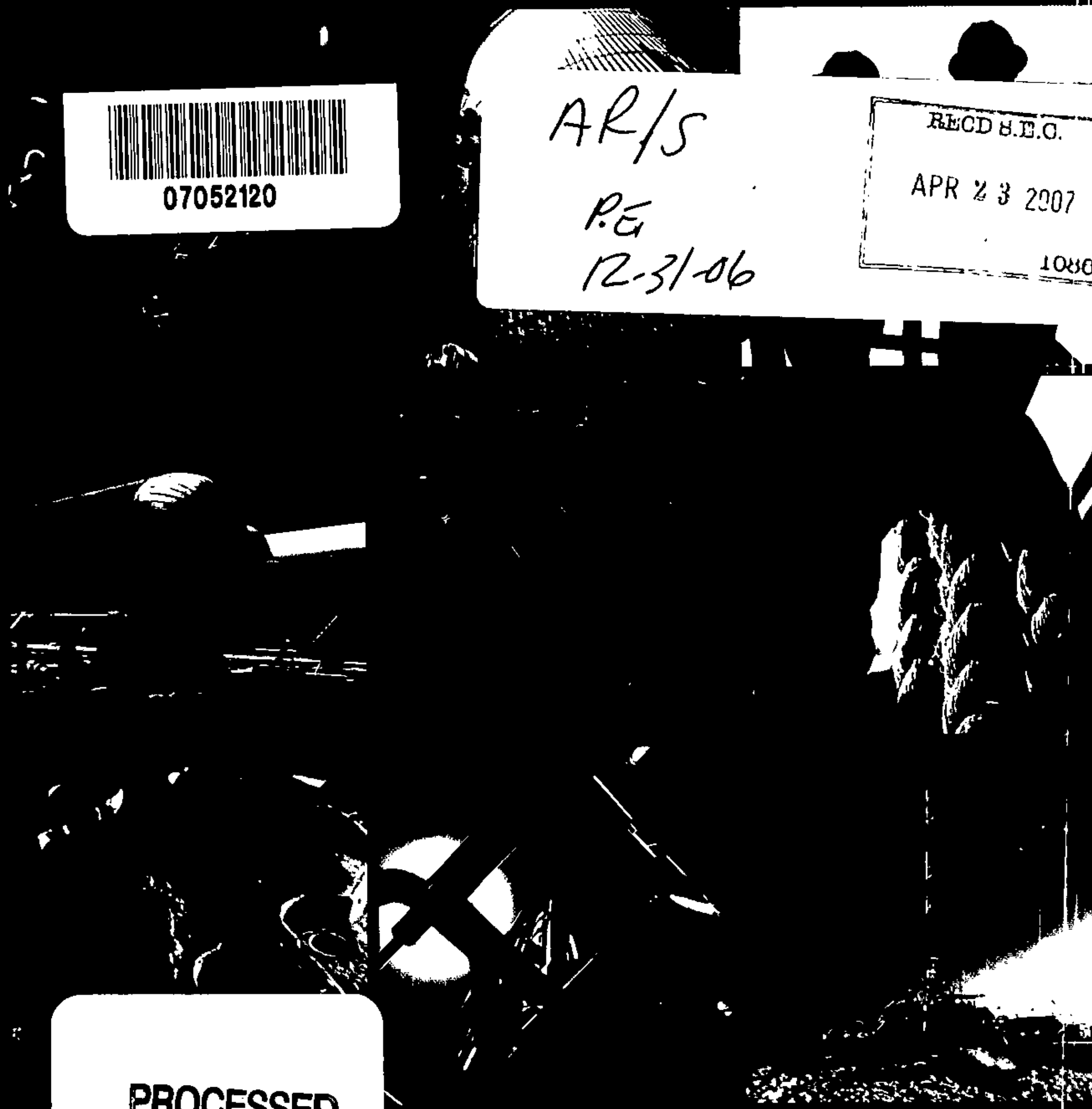


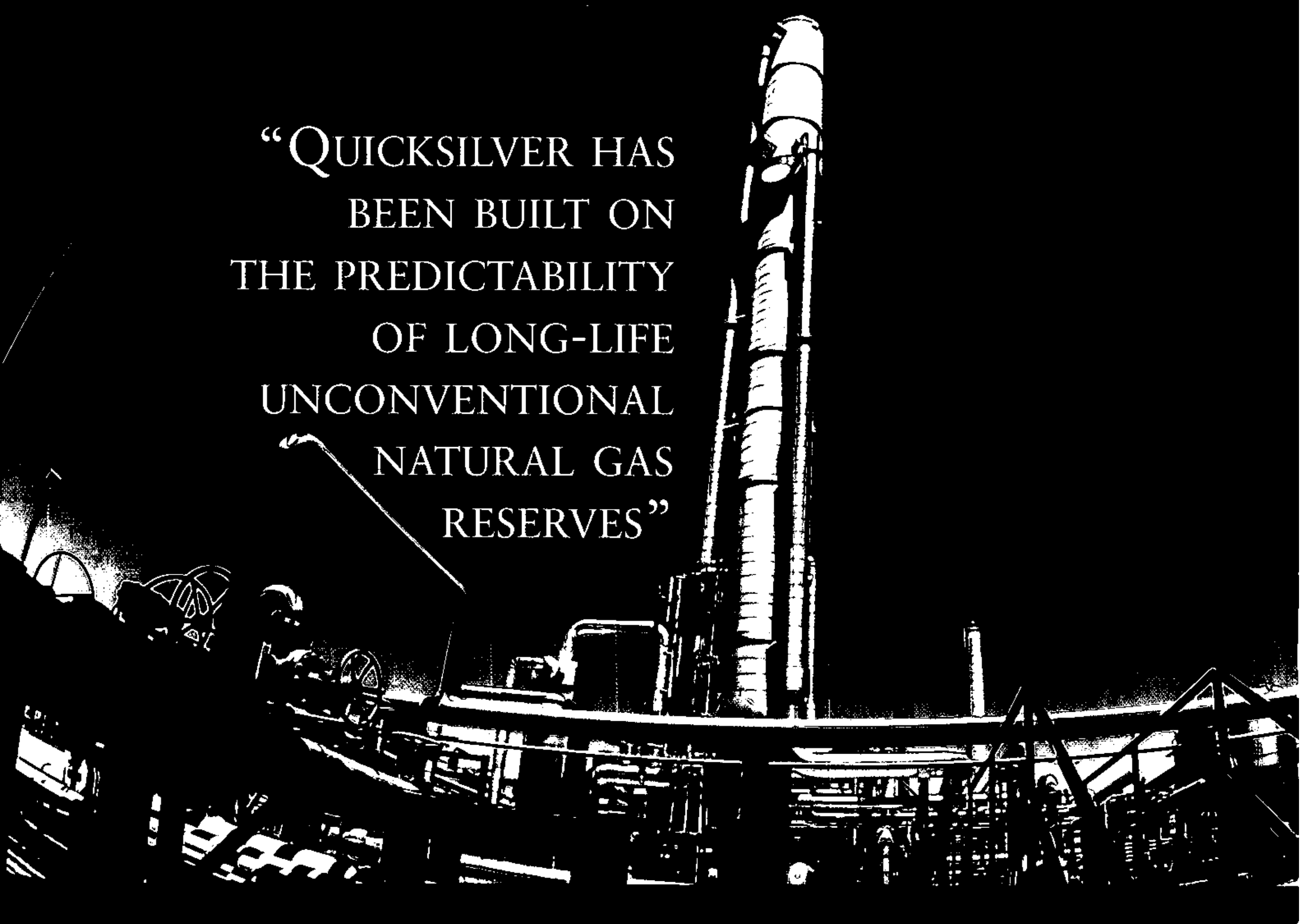
2006 ANNUAL REPORT

COMPANY PROFILE

Quicksilver Resources Inc. is a natural gas and crude oil exploration and production company focused on the development and acquisition of long-lived producing natural gas and oil properties onshore North America. Based in Fort Worth, Texas, the company is widely recognized as a leader in the development and production of unconventional natural gas reserves, including coal bed methane and shale gas. The company's core unconventional natural gas reserves are located in the shales in Michigan, the Fort Worth Basin in north central Texas, and the coals in the Canadian province of Alberta.

As of December 31, 2006, the company had estimated proved reserves of approximately 1.6 trillion cubic feet of natural gas equivalents (Tcfe), of which 98 percent were natural gas and natural gas liquids, and 63 percent were proved developed. The company's common shares are traded on the New York Stock Exchange under the ticker symbol KWK.

Quicksilver Resources is a net asset value company which focuses on growth by the drill-bit and finding and developing long-life unconventional natural gas reserves as a low-cost producer.



TO OUR STOCKHOLDERS,

In such a rapidly changing world, it is comforting to find consistency. For each of the last seven years, we have predicted and shown our stockholders that the next year would be the largest growth year yet for Quicksilver Resources. Well...here we go again, 2007 is expected to be our best growth year ever!

What has led to this consistency? It is our strategy for low-risk, reliable, repeatable growth. Quicksilver has been built on the predictability of long-life unconventional natural gas reserves. Our process is the same for becoming a leader in multiple major unconventional plays in North America:

1) Identify new areas with unconventional resource potential for development.
2) Aggressively acquire large acreage positions.
3) Test these areas in a methodical manner, utilizing the latest technology in drilling, completing, and producing disciplines.
4) Develop the infrastructure of pipelines and processing facilities to provide multiple market options for our products.
5) Efficiently develop the entire project as one of the industry's low finding and development cost producers.

Sticking to this strategy, tossing in some hard work and a little luck, our team at Quicksilver has produced spectacular asset growth for the company. In 2006, Quicksilver's natural gas and oil reserves base grew by more than 40% to approximately 1.6 trillion cubic feet of natural gas equivalents as of December 31, 2006. This growth has come entirely from drilling projects that the company generated internally during the last several years. And, Quicksilver accomplished this growth at industry-leading finding and development costs for new reserves. Even more impressive, these cost efficiencies were achieved against a back-drop of a rapidly escalating cost environment. We thank and congratulate the entire Quicksilver team for these accomplishments.

Today, the production profile of the company is a well-balanced mix from mainly three areas: Michigan, Texas, and Canada. Complementing this mix is production from our Indiana/Kentucky and Montana/Wyoming areas. This is very different than when we started, and quite a bit different from just two years ago. We expect our production profile to change again this year, as Texas, led by the growth in our Barnett Shale development, becomes Quicksilver's largest producing area. The Barnett generates the best return on investment in our project inventory; therefore, approximately 85% of the company's drilling budget is expected to be spent there in 2007.

Another benefit coming from the Barnett development is the creation of a new company, Quicksilver Gas Services LP. This entity was formed to hold Quicksilver's gas processing and gathering assets in the Fort Worth Basin and is expected to be taken public in the near future in the form of a master limited partnership. It is contemplated that Quicksilver Resources will maintain a majority interest in the entity following the public offering.

On the new business front, the company is in the testing phase of our initial drilling in the Delaware Basin for Barnett Shale which is located 500 hundred miles west of Fort Worth. Quicksilver expects to drill additional evaluation wells there this year. This is a large-scale project, and with shale thicknesses several times that of the Fort Worth Basin Barnett, we believe that the potential is significant.

Notwithstanding our progress to date, we forecast an acceleration of the production growth rate during the next several years. The reserves are expected to grow at a rapid clip as well. There will be challenges and we must continue to battle costs, but the company today has the largest inventory of development drilling locations in its history. If we are successful in our new ventures, Quicksilver will have even more to look forward to.

We would like to thank the members of our board of directors, the officers, and the fine employees of Quicksilver for all of their efforts. This company is very fortunate to have such a team. We also look forward to reporting our 2007 results and progress to our supportive stockholders.

Very truly yours,

Thomas Darden
Chairman

Glenn Darden
President and CEO

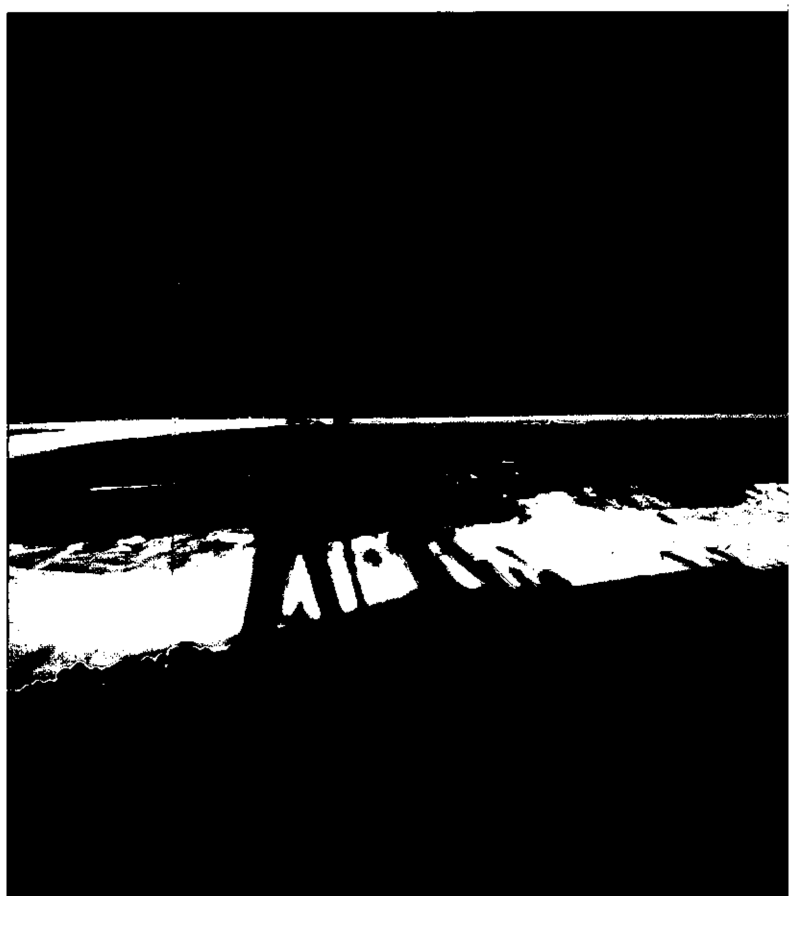
FINANCIAL HIGHLIGHTS

In thousands, except per share, production and product price data	2006	2005	2004	2003	2002
Revenues	$ 390,362	$ 310,448	$ 179,729	$ 140,949	$ 121,979
Income Before Income Taxes and Minority Interest	[illegible]	$ 127,974	$ 45,446	$ 28,502	$ 21,333
Net Income	[illegible]	$ 87,434	$ 31,272	$ 16,208	$ 13,835
Net Income per Diluted Share	[illegible]	$ 1.08	$ 0.41	$ 0.24	$ 0.23
Diluted Weighted Average Number of Shares Outstanding for the Periods	[illegible]	82,455	77,015	68,534	61,182
Total Assets	[illegible]	$ 1,243,094	$ 888,334	$ 666,934	$ 529,538
Long-Term Debt	[illegible]	$ 506,039	$ 399,134	$ 249,097	$ 248,493
Total Stockholders' Equity	[illegible]	$ 383,615	$ 304,276	$ 241,816	$ 128,905
Natural Gas & NGL Production (MMcfe)	[illegible]	48,097	40,124	35,345	33,781
Avg. Natural Gas & NGL Price Per Mcfe (a)	[illegible]	$ 5.78	$ 3.85	$ 3.38	$ 2.74
Crude Oil Production (MBbl)	[illegible]	553	689	808	905
Average Price per Bbl (a)	[illegible]	$ 50.50	$ 33.07	$ 24.23	$ 21.74

(a) Average prices reflect the effect of hedging transactions.

In 2006 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 and crude oil prices; failure or delays in achieving expected production from natural gas and crude oil exploration and development projects; uncertainties inherent in estimates of natural gas and crude oil reserves and predicting natural gas and crude oil reservoir performance, effects of hedging natural gas and crude oil prices; competitive conditions in our industry; actions taken by third-party 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; 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.



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, 2006

OR

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

For the transition period from to

Commission file number: 001-14837

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

Delaware *(State or other jurisdiction of incorporation or organization)*	**75-2756163** *(I.R.S. Employer Identification No.)*
777 West Rosedale St., Suite 300, Fort Worth, Texas *(Address of principal executive offices)*	**76104** *(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, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐

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

As of June 30, 2006, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $1,849,435,922 based on the closing sale price of $36.81 as reported on the New York Stock Exchange.

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

Class	Outstanding at February 15, 2007
Common Stock, $0.01 par value per share	78,040,684 shares

DOCUMENTS INCORPORATED BY REFERENCE

Document	Parts Into Which Incorporated
Proxy Statement for the Annual Meeting of Stockholders to be held May 23, 2007	Part III

INDEX TO ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2006

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.

All share and per share amounts have been adjusted to reflect a three-for-two stock split effected in the form of a stock dividend in June 2005.

Quantities of natural gas are expressed in this report in terms of thousand cubic feet ("Mcf"), million cubic feet ("MMcf"), billion cubic feet ("Bcf") or trillion cubic feet ("Tcf"). Crude oil and natural gas liquids are quantified in terms of barrels ("Bbl"), thousands of barrels ("MBbl") or millions of barrels ("MMBbl"). Crude oil and natural gas liquids are compared to natural gas in terms of thousands of cubic feet of natural gas equivalent ("Mcfe"), millions of cubic feet of natural gas equivalent ("MMcfe") or billions of cubic feet of natural gas equivalent ("Bcfe"). One barrel of crude oil or natural gas liquids is the energy equivalent of six Mcf of natural gas. Natural gas volumes also may be expressed in terms of one million British thermal units ("MMBtu"), which is approximately equal to one Mcf. Daily natural gas and crude oil production is signified by the addition of the letter "d" to the end of the terms defined above. With respect to information relating to working interests in wells or acreage, "net" natural gas and crude oil wells or acreage is determined by multiplying gross wells or acreage by the working interest we own. Unless otherwise specified, all reference to wells and acres are gross.

PART I

ITEM 1. *Business*

We are a Fort Worth, Texas-based independent oil and gas company engaged in the development and production of natural gas, natural gas liquids ("NGLs") and crude oil, which we attain through a combination of developmental drilling, exploitation and property acquisitions. Our efforts are principally focused on unconventional reservoirs found in fractured shales, coal seams and tight sands. We were organized as a Delaware corporation in 1997 and became a public company in 1999 through a merger with MSR Exploration Ltd. ("MSR"). Mercury Exploration Company ("Mercury"), which made significant contributions of properties to us at the time of our formation, was founded by Frank Darden in 1963 to explore for and develop conventional oil and gas properties in the United States. As of December 31, 2006, 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 four 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.

Our operations are concentrated in the Fort Worth, Michigan and Western Canadian Sedimentary Basins. At December 31, 2006, we had estimated proved reserves of 1.57 Tcfe, of which approximately 98% were natural gas and NGLs and approximately 63% were proved developed. Our asset base is geographically diverse, with approximately 45% of our reserves in Texas, 33% in Michigan and 20% in Canada. Since going public in 1999, we have grown our reserves and production at a compound annual growth rate of 25% and 16%, respectively. We believe that much of our future growth will be through development, exploitation and exploration of our leasehold interests, including those in the Barnett Shale formation in the Fort Worth Basin in north Texas, coal bed methane ("CBM") formations in Alberta, Canada, and the Barnett Shale and Woodford Shale formations in the Delaware Basin in west Texas. Although our Michigan operations generate significant cash flow, we believe that our future reserve and production growth will come primarily from our Canadian and Texas operations. These projects represent an extension of our significant expertise in unconventional gas reserves.

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 2007, we have established a capital budget of $610 million, of which we have allocated $502 million for drilling activities, $88 million for gathering and processing facilities, $18 million for acquisition of additional leasehold interests and $2 million for other property and equipment. On a regional basis, $425 million has been allocated to the Fort Worth Basin for drilling approximately 170 wells, an increase of over 50 percent when compared to 2006 drilling activity. Canada has been allocated $54 million for drilling and is expected to increase production by approximately 10% in 2007 when compared to 2006 production. In Michigan $18 million has been allocated for drilling in 2007. The remaining $5 million of drilling capital is spread among our other operating areas, Indiana, Kentucky and Montana. The budget for gathering and processing by region is $69 million for Texas, $15 million for Canada, and $4 million for Michigan.

For the year ended December 31, 2006, we had average daily production of 167.8 MMcfed and total production of 61.3 Bcfe. The following table presents our proved reserves and our average daily production for the year ended December 31, 2006. In addition, our geographic segment information is included at note 22 of our consolidated financial statements included in Item 8 of this report.

Areas of Operations	Proved Reserves (Bcfe)	% Natural Gas and NGLs	% Proved Developed	2006 Production (MMcfed)
Texas	703.9	100%	37%	34.7
Michigan	521.4	96%	91%	75.1
Alberta, Canada	308.4	100%	71%	50.1
Other	33.9	57%	89%	7.9
Total	1,567.6	98%	63%	167.8

Our operations in Texas are located in the Fort Worth Basin. Since 2003, when we began exploration and development there, 116 (96.0 net) wells have been completed and tied into sales. We drilled 111.3 net wells in the Fort Worth Basin during 2006 bringing the total number of wells we have drilled in the basin to 157 net wells through December 31, 2006. Substantially all these wells have been horizontal wells. We anticipate drilling an additional 160 to 180 net wells in the basin during 2007 and approximately 200 to 220 net wells in 2008. We expect that wells we plan to drill in 2007 and 2008 will be substantially horizontal wells. At December 31, 2006, we had 12 drilling rigs operating for us in the Fort Worth Basin, and we expect to increase the number of rigs to 16 during 2007. In 2006, sales from Texas averaged 34.7 MMcfed and at December 31, 2006, our wells in the Fort Worth Basin were producing approximately 53.9 net MMcfed. At December 31, 2006, proved reserves from our interests in the Fort Worth Basin totaled 703.9 Bcfe, and we held a net acreage position of approximately 275,000 acres in Texas.

We have constructed additional infrastructure to augment our development, exploitation and exploration of the Fort Worth Basin. At the end of 2006, we had approximately 120 miles of natural gas gathering lines, ranging from 2 inches to 20 inches, which we refer to as the Cowtown Pipeline. The Cowtown Pipeline transports natural gas produced from Quicksilver and third party wells to our natural gas processing plant in Hood County, Texas ("Cowtown Plant"). We also own a 22-mile NGL pipeline that runs from our Cowtown Plant to a third party pipeline interconnect. During 2007, we expect to add natural gas gathering lines as we, and other third parties, continue to drill and complete wells in the area. We have acquired right-of-way and are in the process of building a second NGL transportation line to an NGL intrastate pipeline approximately four miles east of our Cowtown Plant. Upon completion of a new state-of-the-art gas processing unit in early 2007, Cowtown Plant will have processing capacity of 200 MMcfd. We have begun planning for a third gas processing unit that we anticipate will be operational in late 2008 and bring processing capacity to 325 MMcfd.

We conduct our Canadian operations through our wholly-owned subsidiary, Quicksilver Resources Canada Inc., ("QRCI"), formerly known as MGV Energy Inc. Since 2003, when QRCI ended its joint venture with EnCana, we have expanded our operations in the Western Canadian Sedimentary Basin. Net gas sales from our projects in Alberta averaged 50.1 MMcfd for 2006 and were producing approximately 57.4 MMcfed at December 31, 2006. During 2006, we drilled 400 (215.2 net) productive wells with 336 gross (187.2 net) wells completed and tied into sales. Also during 2006, we installed ten CBM facilities for processing our natural gas production. During 2007, QRCI plans to drill 438 (225 net) wells and has included $3 million in its 2007 drilling budget for additional testing in its Mannville exploration project.

As of December 31, 2006, we had 308.4 Bcfe of Canadian proved reserves, which were primarily attributable to our CBM projects, and held approximately 234,300 net undeveloped acres. At December 31, 2006, Canada comprised 20% of our reserves, 30% of our annual production and approximately $69 million, or 32%, of our cash flow from operations.

In Michigan we produce gas from the Antrim Shale as well as non-Antrim reservoirs. Total production in Michigan for 2006 averaged 75.1 MMcfd and total proved reserves in Michigan were 521.4 Bcfe at December 31, 2006. In the Michigan Antrim Shale, we drilled or participated in 83 (49.3 net) Antrim wells during 2006. Net production in 2006 for our interests in the Antrim Shale averaged 55.6 MMcfd and December 31, 2006 proved reserves were 451.5 Bcf. Net production from our Michigan non-Antrim properties averaged 19.5 MMcfed. Proved reserves from our interests in our non-Antrim properties were 69.9 Bcfe.

Production from our Indiana/Kentucky properties averaged 4.7 MMcfd for 2006 while production from our properties in the Rocky Mountains averaged 3.3 MMcfed. At December 31, 2006, our proved reserves were 17.4 Bcfe from our Indiana/Kentucky interests and 16.4 Bcfe from Rocky Mountain interests in the U.S.

BUSINESS STRENGTHS

High quality asset base with long reserve life. We had total proved reserves of 1.57 Tcfe as of December 31, 2006, of which approximately 98% were natural gas and NGLs and approximately 63% were proved developed. The majority of these reserves are located in three core areas: the Fort Worth Basin in Texas, the Michigan Basin and the Western Canadian Sedimentary Basin in Alberta, Canada, which accounted for approximately 45%, 33% and 20%, respectively, of our proved reserves. Based on average daily production of 167.8 MMcfe for the year ended December 31, 2006, our implied reserve life (proved reserves divided by 2006 annual production) was 25.6 years and our implied proved developed reserve life was 16.1 years. We believe our assets are characterized by long reserve lives and predictable well production profiles. As of December 31, 2006, we were the operator of approximately 78% of our proved reserves.

Significant development and exploitation drilling inventory. As of December 31, 2006, we owned leases covering over 1.4 million net acres in our core areas of operation, of which 71% were undeveloped. This drilling inventory should provide us with more than 4,000 identified drilling locations which we expect to exploit over the next eight to ten years. Our drilling success rate has averaged 98% over 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 2007, we have budgeted approximately $502 million for drilling projects.

Proven track record of organic reserve and production growth. Over the last three years, we have added approximately 865 Bcfe to our reserves, virtually all of which was achieved organically. 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 Horseshoe Canyon formation in Alberta and the Barnett Shale formation in the Fort Worth Basin. We believe our current acreage position will enable us to continue our reserve and production growth.

Experienced management and technical teams. 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 oil and gas business their entire professional careers. Since our formation, they, along with an experienced executive management team, have successfully implemented a disciplined growth strategy with a primary focus on net asset value growth through the development of unconventional reserves. Our executive management team is supported by a core team of technical and operating managers who have significant industry experience, including experience in drilling and completing horizontal wells and in unconventional reservoirs.

BUSINESS STRATEGY

Our business strategy is designed to achieve our principal objectives of cost effective growth in reserves and production which result in growth of earnings and cash flow. Key elements of our business strategy include:

Focus on core areas of operation. We intend to continue to focus on exploiting our significant development inventory in our Barnett Shale properties in the Fort Worth Basin and our Canadian CBM properties in the Western Canadian Sedimentary Basin. We anticipate drilling approximately 400 net development wells in these formations in 2007. We also plan to continue to evaluate potential development opportunities in the Mannville CBM in Canada by drilling resource assessment wells and complete our evaluation of three resource assessment wells drilled during 2006 in the Delaware Basin in west Texas. We also plan to optimize our production in Michigan through additional horizontal recompletions and other infill drilling opportunities. 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 strategy. Through our activities in each of the Michigan, Western Canadian Sedimentary and Fort Worth Basins, we have developed significant expertise in developing and operating reservoirs found in fractured shales, coal seams and tight sands. We have focused on identifying and evaluating opportunities that allow us to apply this expertise and experience to the development and operation of other unconventional reservoirs. Our Barnett Shale play in Texas and our Horseshoe Canyon CBM play in Canada are the most significant examples of the success of this strategy. The Delaware Basin in Texas and the Mannville CBM in Canada represent our most recent opportunities to apply this strategy again in areas that are today considered exploration plays.

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 and crude oil from the areas where we have production to third-party distribution pipelines. 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-party providers. We also monitor on a daily basis the spot markets and seek to sell our uncommitted production into the most attractive markets.

Maintain conservative financial profile. We believe that maintaining a conservative financial structure will position us to capitalize on opportunities to limit our financial risk. We have also established return thresholds for new projects. 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 natural gas sales contracts with price floors and natural gas and crude oil financial hedges.

PROPERTIES

We own significant natural gas and crude oil production interests in the following geographic areas:

Texas

Our operations in the Fort Worth Basin in northern Texas comprised approximately 45% of our estimated proved reserves and approximately 21% of our average daily production for the year ended December 31, 2006. The 2007 capital budget allocated to our Texas interests is approximately $425 million for drilling 191 (171 net) wells. We anticipate drilling approximately 200 to 220 net wells in 2008.

During 2006, we drilled 111.3 net wells in the Fort Worth Basin Barnett Shale and at December 31, 2006, we had drilled a total of 157 net wells in the basin and were producing from 116 (96.0 net) wells. Our interests are spread over an area stretching north-to-south from central Tarrant County to central Bosque County, and west-to-east from eastern Erath County through Hill County. At December 31, 2006, we held approximately 275,000 net acres in the Fort Worth Basin Barnett Shale play with approximately 2,000 drilling locations.

In April 2006, we began operation of a 75 MMcfd natural gas processing unit in Hood County, Texas. Completion of a newly constructed state-of-the-art processing unit with processing capacity of 125 MMcfd is expected in early 2007. At our Cowtown Plant, we process natural gas to extract the NGLs from the natural gas stream and deliver the residue gas to third party intrastate pipelines. We have begun planning for a third processing unit that we expect to become operational in the fourth quarter of 2008. We expect the third unit to provide 125 MMcfd of additional capacity and bring the total processing capacity to 325 MMcfd.

Our pipeline system located in the southern portion of the Fort Worth Basin includes approximately 120 miles of natural gas gathering pipelines, ranging from 2 inches to 20 inches in diameter and a 22-mile NGL pipeline that runs from the Cowtown Plant to an interconnecting third party pipeline. The pipeline system gathers and delivers natural gas produced by our wells and those of third parties to the Cowtown Plant. We expect to continue to construct additional pipelines to gather and transport natural gas to the Cowtown Plant as additional wells in the Fort Worth Basin are drilled and completed. We have acquired right-of-way and are in the process of building a second NGL transportation line to an NGL intrastate pipeline four miles east of our Cowtown Plant. The budget for 2007 includes approximately $69 million for our Fort Worth Basin pipelines and natural gas processing facility.

During 2005, we acquired approximately 310,000 net acres in a contiguous block of west Texas. We drilled three resource assessment wells on that acreage to evaluate the Barnett and Woodford Shales in the Delaware Basin during 2006. We are continuing to evaluate these resource assessment wells and hope to complete that evaluation during 2007.

Michigan

Our Michigan operations comprised approximately 33% of our estimated proved reserves and approximately 45% of our average daily production for the year ended December 31, 2006. Michigan has favorable natural gas supply/demand characteristics as the state has been importing an increasing percentage of its natural gas and currently imports approximately 75% of its demand. This supply/demand situation has allowed us to sell our natural gas production at a slight premium to industry benchmark prices.

Producing Formation	Proved Reserves (Bcfe)	% Gas	% Proved Developed	2006 Production (MMcfed)
Antrim Shale	451.5	100%	93%	55.6
Non-Antrim	69.9	55%	84%	19.5
All Formations	521.4	96%	91%	75.1

The Antrim Shale underlies a large percentage of our Michigan acreage and is fairly homogeneous in terms of reservoir quality; wells tend to produce relatively predictable amounts of natural gas in this reservoir. Subsurface fracturing can increase reserves and production attributable to any particular well. On average, Antrim Shale wells have a total productive life of more than 20 years. As new wells produce and the de-watering process takes place, they tend to reach a maximum production level in six to 12 months, remaining at these levels for one to two years, and then declining at 8% to 10% per year thereafter. The wells tend to produce the best economic results when drilled in large numbers in a fairly concentrated area. This well concentration provides for a more rapid de-watering of a specific area, which decreases the time to natural gas production and increases the amount of natural gas production. It also enables us to maximize the use of existing production infrastructure, which decreases per unit operating costs. Since reserve quantities and production levels over a large number of wells are fairly predictable, maximizing per well recoveries and minimizing per unit production costs through a sizeable well-engineered drilling program are the keys to profitable Antrim development.

Our non-Antrim interests are located in several reservoirs including the Prairie du Chien ("PdC"), Richfield, Detroit River Zone III ("DRZ3") and Niagaran pinnacle reefs. Depending upon the area and the particular zone, the PdC will produce dry gas, gas and condensate or oil with associated gas. Our PdC production is well established, and there are numerous proved non-producing zones in existing well bores that provide recompletion opportunities, allowing us to maintain or, in some cases, increase production from our PdC wells as currently producing reservoirs deplete.

Our Richfield/Detroit River wells are located in Kalkaska and Crawford counties in the Garfield and Beaver Creek fields. The Garfield Richfield has seven wells producing under primary solution gas drive. Potential exploitation of the Garfield Richfield either by secondary waterflood and/or improved oil recovery with CO2 injection is under evaluation; however, because this concept has not been proved there are no recorded reserves related to these techniques.

The DRZ3 at Beaver Creek lies approximately 200 feet above the Richfield reservoir. We had 26 producing wells as of December 31, 2006. Production from the DRZ3 at Beaver Creek consists of oil with associated natural gas. While there is the opportunity for improving production and proved reserve quantities, we have determined that our resources are better allocated to continued development, exploitation and exploration of our many unconventional gas projects.

Our Niagaran wells produce from numerous Silurian-age Niagaran pinnacle reefs located in nine northern Michigan counties. Depending upon the location of the specific reef in the pinnacle reef belt of the northern shelf area, the Niagaran reefs will produce dry gas, gas and condensate or oil with associated gas.

Canada

We began to focus on the potential of Canadian CBM through QRCI in 2000. In late 2000, we entered into a joint venture with EnCana to explore for and develop CBM reserves initially in the West Palliser block in Alberta. In January 2003, we entered into an asset rationalization agreement with EnCana that divided the assets and rights subject to the joint venture and allowed us to pursue independent operations. Since that time, QRCI held interests in

1,924 (925.3 net) productive wells at December 31, 2006. Our total Canadian proved reserves at December 31, 2006 were estimated to be 308.4 Bcf while our average daily production in Canada for 2006 was 50.1 MMcfed.

During 2007, we expect to drill 438 (225 net) wells and install five new CBM processing facilities. Each plant will be capable of processing five to ten MMcfd of natural gas production. Approximately $54 million will be committed to Canadian drilling including approximately $3 million for additional testing of the Mannville coals with an additional $20 million budgeted in 2007 for gathering lines, gas processing facilities and leasehold costs.

Indiana/Kentucky

We began our operations in the New Albany Shale of southern Indiana and north Kentucky in 2000 with the acquisition of 36 producing wells and an eight-mile 12-inch GTG gas pipeline that runs from southern Indiana to northern Kentucky. Our New Albany production is transported through an extension of our GTG gas pipeline that we constructed in 2003 and connects to the Texas Gas Pipeline in northern Kentucky. For 2006, natural gas sales from our properties in the area averaged 4.7 MMcfd.

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, 2006, our Rocky Mountain proved reserves were 2.4 MMBbls of crude oil and 1.9 Bcfe of natural gas and NGLs for total equivalent reserves of 16.4 Bcfe. Daily production from our properties in the Rocky Mountain region averaged 3.3 MMcfed for 2006.

MARKETING

We sell natural gas, NGLs and crude oil to a variety of customers, including utilities, major oil and gas companies or their affiliates, industrial companies, large trading and energy marketing companies and other users of petroleum products. Because our products are commodity products sold primarily on the basis of price and availability, we are not dependent upon one purchaser or a small group of purchasers. Accordingly, the loss of a single purchaser in the areas in which we sell our products would not materially affect our sales. During 2006, the largest purchaser of our products was DTE Energy Trading Inc., which accounted for approximately 10% of our total natural gas, NGL and crude oil sales.

COMPETITION

We encounter substantial competition in acquiring oil and gas leases and properties, marketing natural gas and crude oil, securing personnel and conducting our drilling and field operations. Our competitors in development, exploitation, exploration, acquisitions and production include the major oil and gas 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 natural exploration, development, production and pipeline gathering 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 wastes as "hazardous wastes" and make the reclassified wastes subject to more stringent handling, disposal and clean-up restrictions. Compliance with environmental requirements generally could have a materially adverse effect upon our financial position, results of operations and cash flows. Although we have not experienced any materially adverse effect from compliance with environmental requirements, we cannot assure you that this will continue in the future.

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

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

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

In Canada, the oil and gas 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 oil and gas 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 oil and gas operators in Alberta and also imposes penalties for violations.

INTERNET WEBSITE

We file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission, or SEC. Our SEC filings are available to the public over the Internet at the SEC's website at *www.sec.gov* or from our website at *www.qrinc.com.* You may also read and copy any document we file at the SEC's public reference room located at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the operations of the public reference room. In addition, we make available free of charge through our Internet website at http://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 Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Additionally, charters for the committees of our Board of Directors and our Corporate Governance Guidelines and Code of Business Conduct and Ethics can be found on our Internet website at http://www.qrinc.com under the heading "Corporate Governance." Stockholders may request copies of these documents by writing to the Investor Relations Department at 777 West Rosedale Street, Suite 300, Fort Worth, Texas 76104.

EMPLOYEES

As of February 15, 2007, we had 488 full time employees and 6 part time employees. There are no collective bargaining agreements.

EXECUTIVE OFFICERS

The following information is provided with respect to our executive officers as of February 15, 2007.

Name	Age	Position(s)
Thomas F. Darden	53	Director and Chairman of the Board
Glenn Darden	51	Director, President and Chief Executive Officer
Anne Darden Self	49	Director and Vice President — Human Resources
Jeff Cook	50	Executive Vice President — Operations
John C. Cirone	57	Senior Vice President, General Counsel and Secretary
Philip Cook	45	Senior Vice President — Chief Financial Officer
D. Wayne Blair	50	Vice President, Controller and Chief Accounting Officer
William S. Buckler	45	Vice President — U.S. Operations
Robert N. Wagner	43	Vice President — Reservoir Engineering
MarLu Hiller	44	Vice President — Treasurer

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

THOMAS F. DARDEN has served on our Board of Directors since December 1997. He also served at that time as President of Mercury Exploration Company ("Mercury"). During his term as President of Mercury, Mercury developed and acquired interests in over 1,200 producing wells in Michigan, Indiana, Kentucky, Wyoming, Montana, New Mexico and Texas. Prior to joining us, Mr. Darden was employed by Mercury or its parent corporation, Mercury Production Company, for 22 years. He became a director and the President of Mountain States Resources, Inc. ("MSR") on March 7, 1997. On January 1, 1998, he was named Chairman of the Board and Chief Executive Officer of MSR. He was elected our President when we were formed and then Chairman of the Board and Chief Executive Officer on March 4, 1999, the date of our acquisition of MSR. He served as our Chief Executive Officer until December 1999.

GLENN DARDEN has served on our Board of Directors since December 1997. Prior to that time, he served with Mercury for 18 years, and for the last five of those 18 years was the Executive Vice President of Mercury. Prior to working for Mercury, Mr. Darden worked as a geologist for Mitchell Energy Company LP (subsequently merged with Devon Energy). Mr. Darden became a director and Vice President of MSR on March 7, 1997, and was named President and Chief Operating Officer of MSR on January 1, 1998. He served as our Vice President until he was elected President and Chief Operating Officer on March 4, 1999. Mr. Darden then became our Chief Executive Officer in December 1999.

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 with Banc PLUS Savings Association in Houston, Texas. She was employed as Marketing Director and then spent three years as Vice President of Human Resources. She worked from 1987 to 1988 as an Account Executive for NW Ayer Advertising Agency. Prior to 1987, she spent several years in real estate management.

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

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. He was employed by Union Pacific Resources 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 was promoted to the position of

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.

PHILIP COOK became our Senior Vice President — Chief Financial Officer in October 2005. From October 2004 until October 2005, Mr. Cook served as President, Chief Financial Officer and Director of EcoProduct Solutions, a Houston-based 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.

D. WAYNE BLAIR became our Vice President, Controller and Chief Accounting Officer in 2002, after serving as our Vice President — Controller since July 2000. He is a Certified Public Accountant with over 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 as Vice President — Controller, he served as Controller for Mercury since 1996.

WILLIAM S. BUCKLER became our Vice President — U.S. Operations in August 2005. He joined us in September 2003 as an Engineering Manager. Prior to that, he was an Operations/Engineering Supervisor with Mitchell Energy Company LP (subsequently merged with Devon Energy) from January 2002 until August 2003, and held various other positions with Mitchell Energy, including Region Engineer, from July 1997 until January 2002.

ROBERT N. WAGNER became our Vice President — Reservoir Engineering in December 2002. He had served 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. for over eight years and served as both drilling engineer and production engineer.

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 over 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 serving in various capacities, including Manager of Accounting for Union Pacific Fuels, which was Union Pacific Resources' marketing company.

ITEM 1A. *Risk Factors*

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. In evaluating us, you should consider carefully, among other things, the factors and the specific risks set forth below, and in documents we incorporate by reference. This annual report contains forward-looking statements that involve risks and uncertainties.

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 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 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 New York Mercantile Exchange ("NYMEX") wholesale price of natural gas was at a six-year low of approximately $2.98 per Mcf for August of 2002 and reached an all-time high of approximately $13.91 per Mcf for October of 2005. During 2006, the closing NYMEX wholesale natural gas price ranged from $11.45 per Mcf for January of 2006 to a low of $4.20 per Mcf for October of 2006. 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;
- political conditions in oil and gas producing regions; and
- worldwide economic conditions.

Due to the volatility of natural gas and crude oil prices and our inability to control the factors that 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 take writedowns.

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 in 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 and crude oil reserves. A write down of these capitalized costs could be required if natural gas and/or crude oil prices were to drop precipitously at a reporting period end. 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 write down.

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 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 and crude oil reserves are inherently imprecise.

Actual future production, natural gas 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 and crude oil prices and other factors, many of which are beyond our control.

At December 31, 2006, approximately 37% of our estimated proved reserves were undeveloped. Undeveloped reserves, by their nature, are less certain. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling 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 and crude oil reserves and the costs associated with these reserves in accordance with industry standards and SEC requirements, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that actual results will be as estimated.

You should not assume that the present value of future net revenues disclosed in this annual report is the current market value of our estimated 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 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 accurate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

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

Approximately 45% of our 2006 production was from Michigan, approximately 30% was from Alberta, Canada and approximately 21% was from Texas. 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.

If our production levels were significantly reduced to levels below those for which we have entered into contractual delivery commitments, we would be required to purchase natural gas at market prices to fulfill our obligation under certain long-term contracts. This could adversely affect our cash flow to the extent any such shortfall related to our sales contracts with floor pricing.

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, 2006, our proved Canadian reserves were estimated to be 308 Bcf. Capital expenditures relating to QRCI's operations are budgeted to be approximately $74 million in 2007, constituting approximately 12% of our total 2007 budgeted capital expenditures.

We expect that our 2007 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 be unable to fund our entire 2007 Canadian capital budget, or may opt to increase our Canadian debt levels to fund 2007 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 substantial capital expenditure and working capital needs, particularly as a result of increases in our property acquisition and drilling activities. 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 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 oil and gas business involves operating hazards such as well blowouts, explosions, uncontrollable flows of crude oil, natural gas or well fluids, fires, formations with abnormal pressures, treatment plant "downtime", pipeline ruptures or spills, pollution, releases of toxic gas and other environmental hazards and risks, any of which could cause us to experience substantial losses. Also, the availability of a ready market for our natural gas and crude oil production depends on the proximity of reserves to, and the capacity of, natural gas and crude oil gathering systems, treatment plants, pipelines and trucking or terminal facilities.

U.S. and Canadian federal, state and provincial regulation of oil and gas production and transportation, tax and energy policies, changes in supply and demand and general economic conditions could adversely affect our ability to produce and market our natural gas 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, the payment of which could reduce or eliminate funds available for exploration, development or acquisitions. 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.

We may be unable to make additional acquisitions of producing properties or successfully integrate them into our operations.

A portion of our growth in recent years has been due to acquisitions of producing properties. We expect to continue to evaluate and, where appropriate, pursue acquisition opportunities on terms our management considers to be favorable to us. We cannot assure you that we will be able to identify suitable acquisitions in the future, or that we will be able to finance these acquisitions on favorable terms or at all. In addition, we compete against other companies for acquisitions, and we cannot assure you that we will be successful in the acquisition of any material producing property interests. Further, we cannot assure you that any future acquisitions that we make will be integrated successfully into our operations or will achieve desired profitability objectives.

The successful acquisition of producing properties requires an assessment of recoverable reserves, exploration potential, future natural gas and crude oil prices, operating costs, potential environmental and other liabilities and other factors beyond our control. These assessments are inexact and their accuracy inherently uncertain, and such a review may not reveal all existing or potential problems, nor will it necessarily permit us to become sufficiently familiar with the properties to fully assess their merits and deficiencies. Inspections may not always be performed on every well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken.

In addition, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may be substantially different in operating and geological characteristics or geographic location than existing properties. While our current operations are located primarily in Michigan, Alberta, Canada, Texas, Indiana, Kentucky and Montana, we cannot assure you that we will not pursue acquisitions of properties in other locations.

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 and crude oil reserves that are economically recoverable. Our proved reserves, a majority of which are in the mature Michigan Basin, 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 development and exploration of our existing properties and acquisitions of producing properties. We cannot assure you, however, that our planned exploration and development projects and acquisition activities will result in significant additional reserves or that we will have continuing success drilling productive wells. Furthermore, while our revenues may increase if prevailing natural gas and crude oil prices increase significantly, our finding costs for additional reserves also could increase.

We cannot control the activities on properties that we do not operate.

As of December 31, 2006, other companies operated properties that included approximately 22% of our proved reserves. As a result, we have a limited ability to exercise influence over operations for these properties or their associated costs. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities. As a result, the success and timing of our drilling and development activities on properties operated by others depend upon a number of factors that are outside of our control, including:

- timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells; and
- selection of technology.

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

At December 31, 2006, other companies owned processing plants and pipelines that delivered approximately 64% of our natural gas production to market in Michigan. Our Canadian production is delivered 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 Chief Executive Officer and our other executive officers and key technical personnel. We cannot assure you that the services of these individuals will be available to us in the future. Because competition for experienced personnel in the oil and gas industry is intense, we cannot assure you that we would be able to find acceptable replacements with comparable skills and experience in the oil and gas 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 most of our competitors.

We compete with major and independent oil and gas 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 oil and gas industry competes with other industries in supplying the energy and fuel needs of industrial, commercial, and other consumers.

Several companies have entered into purchase contracts with us for a significant portion of our production and, if they default on these contracts, we could be materially and adversely affected.

Our long-term natural gas contracts, which extend through March 2009, accounted for the sale of approximately 27% of our natural gas production and for a significant portion of our total revenues in 2006. We cannot assure you that the other parties to these contracts will continue to perform under the contracts. If the other parties were to default after taking delivery of our natural gas, it could have a material adverse effect on our cash flows for the period in which the default occurred. A default by the other parties prior to taking delivery of our natural gas could also have a material adverse effect on our cash flows for the period in which the default occurred depending on the prevailing market prices of natural gas at the time compared to the contractual prices.

Hedging our production may result in losses.

To reduce our exposure to fluctuations in the prices of natural gas and crude oil, we have entered into natural gas and crude oil hedging arrangements. These hedging arrangements tend to limit the benefit we would receive from increases in the prices of natural gas 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 crude oil hedges. We do not receive market price cash payments from our customers until 25 to 60 days after the end of the production month. This could have a material adverse effect on our cash flows for the period between hedge settlement and payment for revenues earned.

If we choose not to engage in hedging arrangements in the future, we may be more adversely affected by changes in natural gas 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 and a general shortage of drilling equipment and supplies. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling equipment, crews and associated supplies, equipment and services. We believe that these shortages 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 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;
- 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.

We have a substantial amount of debt and the cost of servicing that debt could adversely affect our business; and such risk could increase if we incur more debt.

We have a substantial amount of indebtedness. At December 31, 2006, we had total consolidated debt of $919.5 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 and crude oil properties. 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. 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 oil and gas 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;
- increase our vulnerability to foreign 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 such 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 facilities 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 control 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 on the date of this annual report approximately 34% of our common stock. As a result, these entities and individuals will generally be able to control 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 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 77,601,922 shares of our common stock outstanding at December 31, 2006. Approximately 49,821,419 of these shares are freely tradable without substantial restriction or the requirement of future registration under the Securities Act. In addition, our contingently convertible debentures are convertible upon the satisfaction of certain conditions. Based on the conversion rate in effect at December 31, 2006, if the conditions permitting the conversion of all of our outstanding contingently convertible debentures are satisfied and all of the outstanding debentures are converted, an aggregate of 4,908,135 shares of our common stock would be issued. At December 31, 2006 we had the following options outstanding to purchase shares of our common stock:

- Options to purchase 26,501 shares at $5.67 per share;
- Options to purchase 45,654 shares at $7.36 per share;
- Options to purchase 36,378 shares at $8.03 per share;
- Options to purchase 560,029 shares at $11.01 per share;
- Options to purchase 17,307 shares at $15.83 per share;
- Options to purchase 921,059 shares at $20.85 per share;
- Options to purchase 10,233 shares at $23.42 per share;
- Options to purchase 67,172 shares at $23.83 per share;
- Options to purchase 2,456 shares at $33.09 per share; and
- Options to purchase 2,401 shares at $44.39 per share.

Sales of substantial amounts of common stock, or a perception that such sales could occur, and the existence of options to purchase 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, such as:

- 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 portion of the information called for by this Item is incorporated herein by reference to the information in Item 1 of this report under the heading "Properties." U.S. borrowings under our senior secured credit facility are secured by our and certain of our domestic subsidiaries' oil and gas properties, and Canadian borrowings under our senior secured credit facility are secured by QRCI's, our and certain of our domestic subsidiaries' oil and gas properties.

OIL AND GAS 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 United States and Canadian properties, respectively. Proved oil and gas reserves, as defined by SEC Regulation S-X Rule 4-10(a) 2(i), 2(ii), 2(iii), (3) and (4), 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. Prices include the effect of our derivative instruments. Future production and development costs include production and property taxes.

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

The reserve data set forth in this document represents only estimates and is subject to inherent uncertainties. The determination of oil and gas 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, 2006, 2005 and 2004.

	Total Proved Reserves			Proved Developed Reserves		
	For the Years Ended December 31,			For the Years Ended December 31,		
	2006	2005	2004	2006	2005	2004
Natural gas (MMcf)						
United States	933,342	716,043	627,676	626,582	593,630	556,999
Canada	308,335	304,910	261,077	217,759	199,859	149,453
Total	1,241,677	1,020,953	888,753	844,341	793,489	706,452
Crude oil (MBbl)						
United States	6,315	5,915	9,067	5,236	4,986	4,587
Canada	—	—	—	—	—	—
Total	6,315	5,915	9,067	5,236	4,986	4,587
NGL (MBbl)						
United States	47,985	9,623	4,187	18,771	5,153	2,464
Canada	16	—	—	16	—	—
Total	48,001	9,623	4,187	18,787	5,153	2,464
Total (MMcfe)	1,567,573	1,114,181	968,276	988,477	854,326	748,762

	Years Ended December 31,		
	2006	2005	2004
Representative natural gas and crude oil prices:(1)			
Natural gas — Henry Hub Spot	$ 5.64	$ 10.08	$ 6.18
Natural gas — AECO	5.39	8.41	5.18
Crude oil — WTI Cushing	60.85	61.06	43.36
Present values (in thousands):(2)			
Standardized measure of discounted future net cash flows, after income tax	$1,485,825	$1,824,132	$970,731

(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 following table sets forth certain information regarding production, average unit prices and costs for the periods indicated:

	Years Ended December 31,		
	2006	2005	2004
Production:			
Natural gas (MMcf)			
United States	35,028	31,944	30,644
Canada	18,237	14,825	8,707
Total natural gas	53,265	46,769	39,351
Crude oil and condensate (MBbl)			
United States	587	553	689
Canada	—	—	—
Total crude oil	587	553	689
NGL (MBbl)			
United States	741	220	128
Canada	5	3	1
Total NGL	746	223	129
Total production (MMcfe)	61,262	51,427	44,257
Average Prices (including impact of hedges):			
Natural gas — per Mcf			
United States	$ 5.90	$ 5.42	$ 3.52
Canada	6.35	6.50	4.92
Consolidated	6.05	5.76	3.83
Crude oil and condensate — per Bbl			
United States	$ 59.99	$ 50.50	$ 33.07
Canada	—	—	—
Consolidated	59.99	50.50	33.07
NGL — per Bbl			
United States	$ 38.78	$ 38.88	$ 28.55
Canada	49.03	53.91	22.18
Consolidated	38.85	39.08	28.52
Average Prices (excluding impact of hedges):			
Natural gas — per Mcf			
United States	$ 5.72	$ 6.44	$ 4.86
Canada	5.82	7.05	4.98
Consolidated	5.75	6.63	4.89
Crude oil and condensate — per Bbl			
United States	$ 60.75	$ 52.76	$ 36.53
Canada	—	—	—
Consolidated	60.75	52.76	36.53
NGL — per Bbl			
United States	$ 38.78	$ 38.88	$ 28.55
Canada	49.03	53.91	22.18
Consolidated	38.85	39.08	28.52
Production cost (per Mcfe) (1)			
United States	$ 2.03	$ 1.90	$ 1.56
Canada	1.29	1.12	1.19
Consolidated	1.81	1.68	1.48

(1) Includes production and ad valorem taxes.

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,					
	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Development:						
United States						
Productive	41.0	32.8	43.0	28.4	73.0	55.5
Non-productive	—	—	—	—	—	—
Canada						
Productive	162.0	86.6	243.0	134.7	356.0	110.1
Non-productive	—	—	—	—	—	—
Total	203.0	119.4	286.0	163.1	429.0	165.6
Exploratory:						
United States						
Productive	161.0	127.4	97.0	66.7	38.0	34.2
Non-productive	7.0	7.0	5.0	5.0	1.0	1.0
Canada						
Productive	238.0	128.6	240.0	124.4	274.0	209.7
Non-productive	—	—	—	—	10.0	9.8
Total	406.0	263.0	342.0	196.1	323.0	254.7
Total:						
Productive	602.0	375.4	623.0	354.2	741.0	409.5
Non-productive	7.0	7.0	5.0	5.0	11.0	10.8
Total	609.0	382.4	628.0	359.2	752.0	420.3

ACQUISITION, EXPLORATION AND DEVELOPMENT CAPITAL EXPENDITURES

	United States	Canada (In thousands)	Consolidated
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
2004			
Proved acreage	$ 11,907	$ 2,942	$ 14,849
Unproved acreage	31,857	7,144	39,001
Development costs	45,213	71,094	116,307
Exploration costs	25,673	22,631	48,304
Total	$114,650	$103,811	$218,461

PRODUCTIVE OIL AND GAS WELLS

The following table summarizes productive oil and gas wells attributable to our direct interests as of December 31, 2006:

	As of December 31, 2006 Productive Wells			
	Natural Gas		Crude Oil	
	Gross	Net	Gross	Net
United States	5,163	1,857.4	390	352.0
Canada	1,922	925.2	2	0.1
Total	7,085	2,782.6	392	352.1

OIL AND GAS ACREAGE

Our principal natural gas and crude oil properties consist of non-producing and producing natural gas and crude oil leases, including reserves of natural gas and crude oil in place. The table found below 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, 2006			
	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Michigan	508,717	216,303	138,763	76,597
Indiana/Kentucky	34,835	34,823	186,306	183,225
Texas	20,847	17,348	826,269	701,307
Rockies & other	86,204	81,790	131,313	95,880
United States	650,603	350,264	1,282,651	1,057,009
Canada	285,523	176,358	328,164	234,282
Total	936,126	526,622	1,610,815	1,291,291

The following table lists the total number of net undeveloped acres as of December 31, 2006, and, with respect to those acres for 2007, 2008 and 2009, 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.

		2007 Expirations		2008 Expirations		2009 Expirations	
	Net Undeveloped Acres	Net Acres	Net Acres with Ext. Opt.	Net Acres	Net Acres with Ext. Opt.	Net Acres	Net Acres with Ext. Opt.
Michigan	76,597	17,356	14,140	5,444	3,248	5,354	1,507
Indiana/ Kentucky	183,225	52,494	2,956	80,651	74,695	17,317	15,636
Texas	701,307	72,626	34,028	84,047	36,390	57,618	15,315
Other U.S.	95,880	10,010	—	4,710	—	10,012	—
Canada	234,282	80,295	—	78,567	—	26,453	—
Totals	1,291,291	232,781	51,124	253,419	114,333	116,754	32,458

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.

ITEM 3. *Legal Proceedings*

In August 2001, a group of royalty owners, Athel E. Williams et al., brought suit against the Company and three of its subsidiaries in the Circuit Court of Otsego County, Michigan. The suit alleges that Terra Energy Ltd., one of Quicksilver's subsidiaries, underpaid royalties or overriding royalties to the 13 named plaintiffs and to a class of plaintiffs who have yet to be determined. The pleadings of the plaintiffs seek damages in an unspecified amount and injunctive relief against future underpayments. On January 21, 2005, the Circuit Court issued an order certifying certain claims to proceed on behalf of a class. On July 25, 2006, the Michigan Court of Appeals reversed the certification of all claims on appeal and remanded the case to the trial court for further proceedings. Based on information currently available to us, we believe that the final resolution of this matter will not have a material effect on our financial position, results of operations, or cash flows.

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 (successor in interest to Eagle Drilling, 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. We seek a declaratory judgment that (i) the contracts are void and (ii) that Eagle is not entitled to early termination compensation provided for in the contracts. We also seek rescission of the contracts and claim we are entitled to recover damages incurred due to Eagle's failure to perform. On October 23, 2006, Eagle Domestic Drilling sued us in District Court of Cleveland County, Oklahoma for (i) breach of contract as to each of the three drilling contracts alleging damages of $29 million plus punitive damages and interest and (ii) tortious breach of contract alleging damages in an unspecified amount in excess of $10,000. Eagle Domestic Drilling also sought a declaratory judgment that, among other things, the contracts are valid and binding. Subsequently, on January 19, 2007, Eagle Domestic Drilling and its parent, Blast Energy Services, Inc., filed for Chapter 11 bankruptcy the United States Bankruptcy Court for the Southern District of Texas, Houston Division. At the date of this filing, the suit in Tarrant County is still pending, but is stayed. On February 21, 2007, the lawsuit in Cleveland County was dismissed. 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 2006.

PART II.

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

Market Information

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

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

	HIGH	LOW
2006		
Fourth Quarter	$43.24	$28.67
Third Quarter	39.82	29.04
Second Quarter	46.17	29.25
First Quarter	52.75	33.06
2005 (1)		
Fourth Quarter	$50.20	$32.94
Third Quarter	48.51	38.23
Second Quarter	43.89	31.45
First Quarter	34.53	22.29

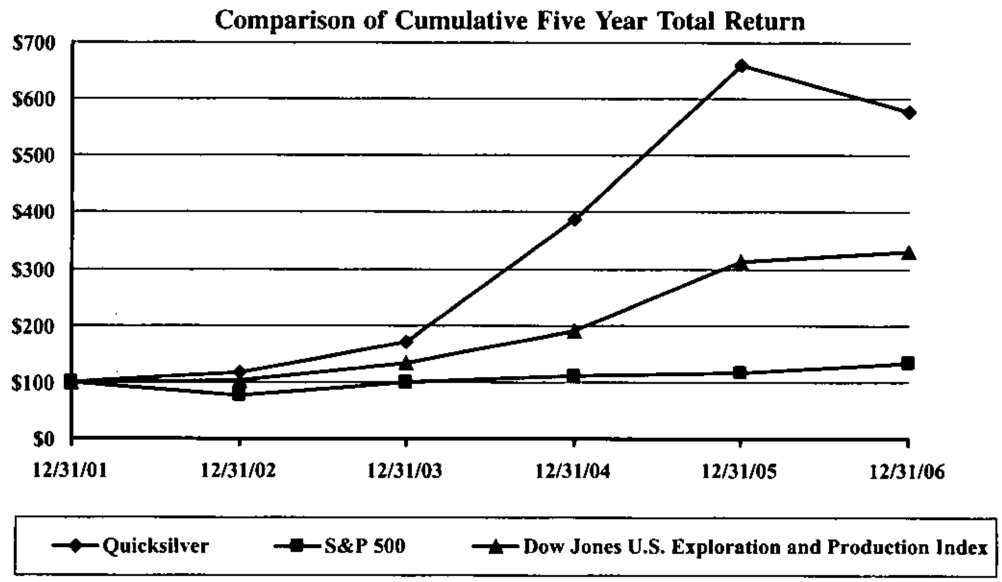
(1) Stock prices been have adjusted to reflect a three-for-two stock split effected in the form of a stock dividend in June 2005.

As of February 15, 2007, there were approximately 561 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 common stock. The indenture for our senior subordinated notes prohibits payments 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") and the Dow Jones U.S. Exploration and Production Index (formerly the Dow Jones Secondary Oils Index) for the period from December 31, 2001 to December 31, 2006, assuming an initial investment of $100 and the reinvestment of all dividends, if any.



Issuer Purchases of Equity Securities

The following table summarizes the Company's repurchases of its common stock during the quarter ended December 31, 2006.

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(2)	Minimum Number of Shares that May Yet Be Purchased Under the Plans or Programs(2)
October 1 to October 31, 2006	80	$34.00	—	—
November 1 to November 30, 2006	—	—	—	—
December 1 to December 31, 2006	150	$38.48	—	—
Total	230	$36.92	—	—

(1) 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 Amended and Restated 1999 Stock Option and Retention Plan.

(2) The Company does not currently have in place any publicly announced, specific plans or programs to purchase equity securities.

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,				
	2006	2005	2004	2003	2002
	(In thousands, except for per share data)				
Consolidated Statements of Income Data:					
Total revenues	$ 390,362	$ 310,448	$ 179,729	$ 140,949	$121,979
Income before income taxes and minority interest	131,960	127,974	45,446	28,502	21,333
Income from continuing operations	93,719	87,272	31,272	18,505	13,835
Income before cumulative effect of change in accounting principle	93,719	87,434	31,272	18,505	13,835
Net income	93,719	87,434	31,272	16,208	13,835
Net income from continuing operations — per share(1)					
Basic	$ 1.22	$ 1.15	$ 0.42	$ 0.28	$ 0.23
Diluted	1.15	1.08	0.41	0.27	0.23
Net income before accounting change — per share(1)					
Basic	$ 1.22	$ 1.15	$ 0.42	$ 0.28	$ 0.23
Diluted	1.15	1.08	0.41	0.27	0.23
Net income — per share(1)					
Basic	$ 1.22	$ 1.15	$ 0.42	$ 0.24	$ 0.23
Diluted	1.15	1.08	0.41	0.24	0.23
Consolidated Statements of Cash Flows Data:					
Net cash provided by (used in):					
Operating activities	$ 220,615	$ 144,468	$ 84,847	$ 49,602	$ 41,650
Investing activities	(590,454)	(319,269)	(205,898)	(137,744)	(81,111)
Financing activities	361,311	172,426	134,389	79,369	40,050
Capital expenditures	$ 597,490	$ 329,495	$ 215,106	$ 137,895	$ 86,417
Consolidated Balance Sheets Data:					
Working capital (deficit)(2)	$ (28,425)	$ (98,606)	$ (17,255)	$ (30,803)	$ (23,678)
Properties — net	1,679,280	1,112,002	802,610	604,576	470,078
Total assets	1,882,912	1,243,094	888,334	666,934	529,538
Long-term debt	919,117	506,039	399,134	249,097	248,493
Stockholders' equity	575,666	383,615	304,276	241,816	128,905

(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 and a three-for-two stock split effected in the form of a stock dividend in June 2005.

(2) Working capital consists of current assets and current liabilities, which include derivative contracts at estimated fair value and the related deferred income taxes.

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, financial condition, results of operations, 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, including: "Item 1. Business," "Item 2. Properties," "Item 6. Selected Financial Data," and "Item 8. Financial Statements and Supplementary Data." 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 accounting policies that represent choices between acceptable alternatives and/or require critical judgments and estimates.
- *Results of Operations* — an analysis of our consolidated results of operations for the three years presented in our financial statements. We continue to operate in the business of development, exploitation, exploration and production of natural gas, NGLs and crude oil. Except to the extent that differences between our geographic operating segments are material to an understanding of our business as a whole, we present this MD&A on a consolidated basis.
- *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 development, exploitation, exploration, acquisition, and production of natural gas, NGLs, and crude oil primarily from 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. We produce these products in quantities and at prices that, in addition to generating operating income, allow us to conduct development, exploitation, exploration and acquisition activities to replace the reserves that have been produced.

At December 31, 2006, approximately 98% of our proved reserves were natural gas and natural gas liquids. Approximately 33% of our proved reserves were located in Michigan. Our activities in the Michigan Basin Antrim shale have allowed us to develop a technical and operational expertise in the development, exploitation, exploration, acquisition and production of unconventional natural gas reserves. Consistent with one of our business strategies, we have applied the expertise gained in our Michigan activities 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 45% and 20%, respectively of our proved reserves at December 31, 2006. The Delaware Basin in west Texas and the Mannville CBM in Alberta represent our most recent opportunities to apply this expertise.

For 2007, we plan to continue our focus on the continued development, exploitation and exploration of our properties in Texas and Alberta. We have allocated $502 million of our 2007 capital budget of $610 million for drilling activities. Approximately $425 million is allocated to our Barnett Shale position in the Forth Worth Basin in Texas and approximately $54 million is allocated to our Canadian CBM projects. Approximately $18 million of the 2007 drilling budget has been dedicated to our fractured shale projects in the Michigan Basin, with the remaining $5 million planned for our projects in Indiana/Kentucky and the Rockies.

Our Company focuses on three key value drivers:

- reserve growth;

• production growth; and

• improving the Company's 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 higher levels of financial risk. Both our lower-risk development programs and higher-risk exploratory projects are aimed at providing the Company with opportunities to develop and exploit unconventional natural gas reservoirs to which our technical and operational expertise is well suited.

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 operations on operated properties to determine if steps can be taken to profitably increase reserves and production.

As these elements are implemented, our results are measured through the following key measurements: reserve growth; production growth; cash flow from operating activities; and earnings per share.

	Years Ended December 31,		
	2006	2005	2004
Reserve growth(1)	46%	20%	17%
Production (MMcfe)	61,262	51,427	44,257
Cash flow from operating activities (in thousands)	$220,615	$144,468	$84,847
Diluted earnings per share	$ 1.15	$ 1.08	$ 0.41

(1) This ratio is calculated by subtracting adjusted beginning of the year proved reserves (December 31, 2005 proved reserves less 2006 production) from end of the year proved reserves and dividing by beginning of the year proved 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 natural gas sales contracts with price floors and natural gas and crude oil financial hedges. Our use of pricing collars and, to a lesser degree, fixed price swaps for both natural gas and crude oil helps to ensure a predictable base 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 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 fluctuate widely. For example, the closing NYMEX wholesale price of natural gas was at an all-time high of approximately $13.91 per Mcf for October 2005 before dropping to approximately $4.20 per Mcf for October 2006. For February 2007 natural gas production, the wholesale price of natural gas was approximately $6.92 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 operating activities to be sufficient to satisfy our total budgeted capital expenditures. We plan to use cash flows from operations, credit facility utilization, possible sales of assets and issuance of debt or equity securities to fund our total budgeted capital expenditures in 2007.

Our wholly-owned subsidiary that will hold Cowtown Plant and the Cowtown Pipeline has filed a registration statement on Form S-1 relating to the offering of approximately 19% of its limited partner interests to the public. Numerous factors, such as general market conditions and market conditions in the oil and gas industry in particular, could result in this offering not being completed.

FINANCIAL RISK MANAGEMENT

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

Our primary risk exposure is related to natural gas and crude oil commodity prices. We have mitigated the downside risk of adverse price movements through the use of long-term sales contracts, swaps and collars; however, in doing so, we have also limited future gains from favorable price movements.

Commodity Price Risk

We enter into long-term natural gas sales contracts and financial derivative contracts to hedge our exposure to commodity price risk associated with anticipated future natural gas production. We sell approximately 10 MMcfd and 25 MMcfd of natural gas under long-term contracts with floor prices of $2.47 per Mcf and $2.49 per Mcf, respectively, through March 2009. Approximately 31.2 MMcfd of our natural gas production was sold under these contracts in 2006 and the remainder were third-party volumes controlled by us. We also enter into financial derivative contracts that include price floors, no-cost collars and fixed price swaps to hedge our exposure to commodity price risk associated with anticipated future production of natural gas, crude oil and condensate and NGLs.

Currently, natural gas price collars have been put in place to hedge 2007 anticipated production of approximately 123 MMcfd. Additionally, we have used price collar agreements to hedge approximately 1,250 Bbld of its crude oil, condensate and NGL anticipated production for 2007. Anticipated 2008 natural gas production of approximately 35 MMcfd has also been hedged using price collars and an additional 40 MMcfd of natural gas production has been hedged using fixed price swaps. 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 financial derivative positions as of December 31, 2006 related to natural gas and crude oil production.

Product	Type	Remaining Contract Period	Volume	Price per Mcf or Bbl	Fair Value
					(In thousands)
Gas	Swap	Jan 2008-Dec 2008	25,000 Mcfd	$ 8.13	$ 609
Gas	Swap	Jan 2008-Dec 2008	7,500 Mcfd	8.13	183
Gas	Swap	Jan 2008-Dec 2008	5,000 Mcfd	8.14	139
Gas	Swap	Jan 2008-Dec 2008	2,500 Mcfd	8.15	78
Gas	Collar	Jan 2007-Apr 2007	10,000 Mcfd	7.50 - 11.00	1,641
Gas	Collar	Jan 2007-Apr 2007	10,000 Mcfd	7.50 - 11.15	1,644
Gas	Collar	Jan 2007-Mar 2007	10,000 Mcfd	7.50 - 9.65	1,257
Gas	Collar	Jan 2007-Mar 2007	10,000 Mcfd	8.00 - 14.72	1,593
Gas	Collar	Jan 2007-Mar 2007	10,000 Mcfd	8.50 - 11.35	2,095
Gas	Collar	Jan 2007-Mar 2007	10,000 Mcfd	8.50 - 11.50	2,101
Gas	Collar	Jan 2007-Mar 2007	20,000 Mcfd	8.00 - 15.00	3,370
Gas	Collar	Jan 2007-Dec 2007	10,000 Mcfd	9.00 - 12.10	8,258
Gas	Collar	Jan 2007-Dec 2007	20,000 Mcfd	9.00 - 12.10	16,515
Gas	Collar	Apr 2007-Oct 2007	10,000 Mcfd	7.50 - 11.50	2,455
Gas	Collar	Apr 2007-Oct 2007	10,000 Mcfd	7.50 - 11.75	2,488
Gas	Collar	Apr 2007-Oct 2007	5,000 Mcfd	7.50 - 11.78	1,249
Gas	Collar	Apr 2007-Oct 2007	5,000 Mcfd	7.50 - 11.80	1,259
Gas	Collar	May 2007-Dec 2007	10,000 Mcfd	7.00 - 9.15	1,724
Gas	Collar	May 2007-Dec 2007	10,000 Mcfd	8.00 - 11.20	3,011
Gas	Collar	Apr 2007-Mar 2008	10,000 Mcfd	9.00 - 12.00	6,477
Gas	Collar	Apr 2007-Mar 2008	10,000 Mcfd	9.00 - 12.05	6,504
Gas	Collar	Nov 2007-Mar 2008	10,000 Mcfd	8.00 - 15.00	1,120
Gas	Collar	Nov 2007-Mar 2008	10,000 Mcfd	8.00 - 15.65	1,222
Oil	Collar	Oct 2006-Jun 2007	1,000 Bbld	50.00 - 85.85	23
Oil	Collar	Oct 2006-Jun 2007	1,000 Bbld	50.00 - 85.85	23
Oil	Collar	Jul 2007-Dec 2007	500 Bbld	70.00 - 91.10	643
Gas	Basis	Jan 2007	1,935 Mcfd		144
Gas	Basis	Jan 2007-May 2007	3,973 Mcfd		14
				Total	$67,839

Utilization of our financial hedging program may result in natural gas and crude oil realized prices varying from market prices that we receive from the sale of natural gas and crude oil. Our revenue from natural gas and crude oil production was $15.5 million higher, $41.8 million lower and $43.9 million lower for 2006, 2005 and 2004, respectively.

We have also entered into financial derivative contracts to hedge exposure to commodity price risk associated with future contractual natural gas sales at fixed prices to third parties. As a result of our firm sale commitments, the associated financial derivative contracts qualified as fair value hedges for accounting purposes. Marketing revenues were $0.2 million lower and $0.1 million and $0.5 million higher as a result of our hedging activities in 2006, 2005 and 2004, respectively.

The following table summarizes our open financial swap positions and hedged firm commitments as of December 31, 2006 related to natural gas marketing.

Contract Period	Volume	Weighted Avg Price per Mcf	Fair Value (In thousands)
Natural Gas Sales Contracts			
Jan 2007-Mar 2007	30,000 Mcf	$ 8.05	$ 53
Natural Gas Financial Derivatives			
Jan 2007-Mar 2007	30,000 Mcf	Floating Price	(53)
Total-net			$ —

Hedge ineffectiveness resulted in $0.1 million of net losses, $0.1 million of net gains and $0.1 million of net losses recorded to other revenue for 2006, 2005 and 2004, respectively.

Our remaining anticipated production for 2007 and beyond is subject to commodity price fluctuations. Under long-term sales contracts, natural gas volumes of 16.5 MMcfd are committed at market price through September 2008. During 2006, approximately 8.9 MMcfd of our natural gas production was sold under these contracts. The remaining contractual volumes were third-party volumes controlled by us.

Based on our 2006 average production and long-term natural gas sales contracts with floor prices of $2.47 per Mcf and $2.49 per Mcf, each $1.00 per Mcf increase/decrease in the price of natural gas would increase/decrease our revenue by approximately $42.0 million.

Interest Rate Risk

At December 31, 2006, we had no interest rate derivatives in effect. On September 10, 2003, we entered into an interest rate swap to hedge the $40.0 million of fixed-rate second lien notes issued on June 27, 2003. The swap converted the debt's 7.5% fixed-rate debt to a floating six-month LIBOR base. In January 2004, the swap position was cancelled, and we received a cash settlement of $0.3 million that was recognized over the original term for the swap until the associated debt was retired in March 2006. At that time, the remaining deferred gain was recognized.

Interest expense for the years ended December 31, 2006, 2005 and 2004 was $0.1 million lower, $0.3 million lower and $0.8 million higher, respectively, as a result of the interest rate swaps.

If interest rates on our variable interest-rate debt of $421.1 million, as of December 31, 2006, increase or decrease by one percentage point, our annual pretax income will decrease or increase by $4.2 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 our natural gas and crude oil production sold at spot or short-term contract prices. All our natural gas and crude oil 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 to support the obligations of our counterparty are required 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. In this manner, we reduce credit risk.

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 companies of the two counterparties to our long-term gas contracts were downgraded in early 2003 and remain below the credit ratings required for the extension of credit to new customers. Please see "Item 1A. Risk Factors."

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. In 2005, foreign currency transaction losses of $0.1 million were recorded as a result of losses in the Canadian-$ value of U.S.-$ bank balances in 2005. During October and November 2004, Quicksilver loaned QRCI approximately $11.4 million. To reduce its exposure to exchange rate risk, QRCI entered into a forward contract that fixed the Canadian-to-US exchange rate. The balance of the loan was repaid at the end of November 2004 and upon settlement of the forward contract, a gain of $0.2 million was recognized.

While cross-currency transactions are minimized, the result of a ten percent change in the Canadian-U.S. exchange rate would increase or decrease stockholders' equity by approximately $15.8 million at December 31, 2006.

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. Effective with the adoption of SFAS No. 143 in 2003, 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 when incurred. Gain or loss on the sale or other disposition of oil and gas properties is 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 the successful efforts method of accounting for oil and gas properties. 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

We are required to perform the ceiling test each quarter because we use the full cost method of accounting for oil and gas properties. Pursuant to SEC Regulation S-X Rule 4-10, the ceiling test is an impairment test performed on a country-by-country basis. The test determines a full cost 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 ten percent 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, an impairment or noncash write down is required. A charge to income for impairment can give us 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 and crude oil. These changes can reduce the amount of economically producible reserves. At December 31, 2006, our net capitalized exploration and production fixed asset costs, inclusive of future development costs, for U.S. and Canadian reserves were $1.07 per Mcfe and $1.53 per Mcfe, respectively.

Oil and Gas Reserves

Proved oil and gas reserves, as defined by SEC Regulation S-X Rule 4-10(a) 2(i), 2(ii), 2(iii), (3) and (4), 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 using available geological and reservoir data as well as production performance data. These estimates, made by our engineers, are reviewed annually and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to 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 hedge risk associated with the prices received from natural gas, crude oil and condensate and NGL production. We also utilize financial derivative instruments to hedge the risk associated with interest rates on our debt outstanding. We account for our derivative instruments under the provisions of Statement of Financial Accounts Standard ("SFAS") No. 133, *Accounting for Derivative Instruments and Hedging Activities*. Under this statement, derivative instruments, other than those meeting the normal purchases and sales exception, are recorded on our balance sheet as either assets or liabilities measured at fair value determined by reference to published future market prices and interest rates. The cash settlement of all derivative instruments is recognized as income or 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. 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, 2006 was estimated based on published market prices of natural gas and crude oil for the periods covered by the contracts. The net differential between the prices in each derivative and commitment and market prices for future periods, as adjusted for estimated basis, has been applied 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. As a result, the fair value of our derivatives and commitments does not necessarily represent the value a third party would pay or require payment of to assume our contract positions.

At December 31, 2006, portions of our hedge derivatives were classified as current based upon the maturity of the derivative instruments. Based upon the estimated fair values of those hedge derivatives as of December 31, 2006, our revenues for 2007 will increase approximately $64.1 million. Net income, after income taxes, will be approximately $42.7 million. These amounts will be reclassified from accumulated other comprehensive income in 2007.

Asset Retirement Obligations

We have significant obligations to remove equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells and associated production facilities. We adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, effective January 1, 2003. Under SFAS No. 143, 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 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 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. This statement 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 123(R) using the modified prospective application method described in the statement. Under the modified prospective application method, we have applied the standard to new awards. 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 123(R) shall be attributed to periods beginning January 1, 2006 using the attribution method that was used under SFAS 123. At January 1, 2006, we had total compensation cost of $1.1 million related to unvested stock options with a weighted average remaining vesting period of 1.5 years. We recorded expense of $0.7 million for stock option grants during 2006.

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 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 123(R). As a result of our net operating losses, the excess tax benefits that would otherwise be available to reduce income taxes payable have the effect of increasing our net operating loss carry forwards. Accordingly, because we are unable to realize these excess tax benefits, such benefits have not been recognized in the condensed consolidated statement of cash flows for the year ended December 31, 2006.

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 are not considered available for distribution to us.

Included in our net deferred tax liability are $117.8 million of future tax benefits from prior unused tax losses. Realization of these tax assets depends on sufficient future taxable income before the benefits expire. We believe we will have sufficient future taxable income to utilize the loss carry forward benefits before they expire; however, if not, we could be required to recognize a loss for some or all of these tax assets. Net operating loss carry forwards and other deferred tax assets are reviewed annually for recoverability and are recorded net of a valuation allowance, if necessary.

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

Summary Financial Data
Years Ended December 31, 2006, 2005 and 2004

	Years Ended December 31,		
	2006	2005	2004
		(In thousands)	
Total operating revenues	$390,362	$310,448	$179,729
Total operating expenses	216,692	162,233	120,214
Operating income	174,196	149,129	60,693
Income from continuing operations	93,719	87,272	31,272
Net income	93,719	87,434	31,272

Net income for the years ending December 31, 2006, 2005 and 2004 was $93.7 million ($1.15 per diluted share), $87.4 million ($1.08 per diluted share), and $31.3 million ($0.41 per diluted share), respectively. Net income for 2005 included a gain of $0.2 million from discontinued operation relating to the sale of drilling rigs purchased and sold during the year.

Operating Revenues

Our 2006 revenues were $390.4 million as compared to $310.4 million for 2005, primarily as a result of additional revenue originating from our expanded operations in the Fort Worth Basin of northern Texas and Alberta, Canada. The additional revenue from our Texas and Canadian operations was the result of a net increase in sales volumes of 8.8 Bcfe and 3.7 Bcfe, respectively, and an increase in our realized prices, on a consolidated basis, of $0.36 per Mcfe.

Total revenues for 2005 were $310.4 million, a $130.7 million increase from the $179.7 million reported in 2004. Higher realized prices and additional sales volumes increased revenue $129.0 million. The increase was primarily the result of sales volumes added from new wells placed into production in our Canadian CBM and Texas Barnett Shale development projects and a 49% increase in realized sales prices.

Gas, Oil and NGL Sales

Our sales volumes, revenues and average prices for the years ended December 31, 2006, 2005 and 2004 are as follows:

	Years Ended December 31,		
	2006	2005	2004
Average daily sales volume			
Natural gas — Mcfd			
United States	95,967	87,518	83,727
Canada	49,966	40,617	23,789
Total	145,933	128,135	107,516
Crude oil and condensate — Bbld			
United States	1,608	1,516	1,882
Canada	—	—	—
Total	1,608	1,516	1,882
NGL — Bbld			
United States	2,029	603	351
Canada	14	8	1
Total	2,043	611	352
Total sales — Mcfed			
United States	117,783	100,223	97,120
Canada	50,057	40,672	23,802
Total	167,840	140,895	120,922
Natural gas, oil and NGL revenue (in thousands)			
United States	$270,535	$209,715	$134,268
Canada	116,005	96,489	42,905
Total natural gas, oil and NGL revenue	$386,540	$306,204	$177,173
Product revenue (in thousands)			
Natural gas sales	$322,357	$269,547	$150,716
Crude oil and condensate sales	35,205	27,947	22,782
NGL sales	28,978	8,710	3,675
Total product sale revenue	$386,540	$306,204	$177,173
Unit prices — including impact of hedges			
Natural gas — per Mcf			
United States	$ 5.90	$ 5.42	$ 3.52
Canada	6.35	6.50	4.92
Consolidated	5.76	5.76	3.83
Crude oil and condensate — per Bbl			
United States	$ 59.99	$ 50.50	$ 33.07
Canada	—	—	—
Consolidated	59.99	50.50	33.07
NGL — per Bbl			
United States	$ 38.78	$ 38.88	$ 28.55
Canada	49.03	53.91	22.18
Consolidated	38.85	39.08	28.52

Our natural gas sales for 2006 were $322.4 million and increased 20%, or $52.8 million, from 2005 natural gas sales of $269.5 million. Realized prices in 2006 (including hedge settlements and our sales contracts with $2.48 per Mcf floors) increased 5% and were responsible for $13.5 million of the increase in natural gas revenue from the prior year. The remaining increase in 2006 natural gas revenue as compared to 2005 was due to a 14% increase in sales volumes. Natural gas sales in the U.S. increased 6.8 Bcf as a result of new Fort Worth Basin wells placed into production throughout 2006 and 0.7 Bcf from new Antrim wells in Michigan placed into production during 2006.

Drilling on our Canadian interests increased production 5.1 Bcf from the 2005 period. These increases were partially offset by natural production rate declines for existing wells.

Crude oil and condensate revenue for 2006 was $35.2 million and $7.3 million higher than crude oil and condensate sales of $27.9 million 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 Fort Worth Basin interests increased 61.2 MBbl as a result of additional wells placed into production during the year. The increase was partially offset by natural production rate declines for existing wells.

Sales of NGLs for 2006 were $29.0 million. As compared to 2005, 2006 sales were $20.3 million higher than 2005 NGL sales of $8.7 million. The increase was the result of an incremental 509.7 MBbl of NGL production resultant from Texas natural gas production and processing during 2006.

Natural gas sales for 2005 were $269.5 million and increased $118.8 million from 2004 natural gas revenue of $150.7 million. Higher natural gas prices in 2005 increased revenue $76.1 million. Realized natural gas prices (including contracts with price floors of $2.48 and settlements for natural gas price hedges) rose 54% and 32%, respectively, for U.S. and Canadian natural gas. Our natural gas production in 2005 increased nearly 7.4 Bcf from 2004 to almost 46.8 Bcf. Continued drilling on our Horseshoe Canyon and other Canadian interests increased production 8.8 Bcf, partially offset by natural declines in production rates for existing Canadian wells. U.S. sales volumes for 2005 were approximately 5% higher than 2004. Our drilling program in the Barnett Shale of the Fort Worth Basin resulted in a production increase of over 3.0 Bcf from Barnett Shale wells drilled and placed into production in the latter half of 2004 and all of 2005. Wells placed into production in the Antrim and New Albany Shales increased production approximately 0.6 Bcf and 0.8 Bcf for 2005. Wells placed into production on our Michigan non-Antrim interests, as well as other work performed on existing wells, increased production approximately 0.3 Bcf for 2005. Natural production rate declines partially offset these increases.

Revenue from crude oil and condensate in 2005 increased $5.1 million despite a decrease of 150 MBbl resulting primarily from the sale of Wyoming crude oil properties in the third quarter of 2004 to Meritage Partners LLC. Price increases of approximately 53% from 2004 realized prices resulted in an average 2005 realized price of $50.50 and increased revenue approximately $12.0 million.

NGL revenue for 2005 was $8.7 million as compared to $3.7 million for 2004. NGL volumes for 2005 increased approximately 94 MBbl primarily as a result of natural gas processing in the Barnett Shale that began in the second quarter of 2005. These additional volumes increased revenue approximately $3.7 million from 2004 while a 37% increase in realized prices provided $1.3 million of additional revenue in 2005.

Other Revenues

Other revenue, consisting primarily of revenue from the processing, gathering and marketing of natural gas, was $4.2 million for 2005. The $1.6 million increase from 2004 was primarily the result of revenue earned from the sale of NGLs earned from gas processed through our interim processing facility in the Barnett Shale. This revenue was not earned for 2006 as the final gas processing agreements entered into in October 2005 do not provide for the facility to earn a portion of the NGLs produced from the plant.

Operating Expenses

Operating expenses for 2006 were $216.7 million, or $54.5 million higher than operating expenses for 2005. Production expenses in 2006 were $24.0 million higher than 2005 production expense due primarily to higher sales volumes from new wells placed into production in Texas and Canada. Depletion and depreciation expense for 2006 increased $23.6 million as a result of higher sales volumes and depletion rates as well as additional depreciation associated with new gas processing and gathering assets in Texas and Canada. General and administrative expense for 2006 also increased $6.0 million compared to 2005.

Operating expenses for 2005 were $162.2 million, a $41.9 million increase from 2004 operating expense. Nearly half of the increase was due to higher sales volumes and new wells placed into production in Canada and Texas as well as an increase in maintenance and repairs for our Michigan properties. Depletion expense for 2005 increased as a result of higher sales volumes and depletion rates. Depreciation also increased as a result of gathering and processing facilities added in Canada and Texas during 2005. There was also a $6.0 million increase in general and administrative costs for 2005 when compared to 2004.

Oil and Gas Production Expense

	Years Ended December 31,		
	2006	2005	2004
	(In thousands, except per unit amounts)		
Production expenses			
United States	$73,251	$55,898	$43,600
Canada	21,925	15,306	9,029
	$95,176	$71,204	$52,629
Production expenses — per Mcfe			
United States	$ 1.70	$ 1.53	$ 1.23
Canada	1.20	1.03	1.04
Consolidated	1.55	1.39	1.19

Expense for oil and gas production for 2006 was $95.2 million and $24.0 million higher than 2005 production expense of $71.2 million. Canadian production expense was $21.9 million in 2006. The $6.6 million increase from 2005 Canadian production expense was primarily the result of a $3.7 million increase in compensation and benefits expense and an increase of $1.7 million for gas processing expense. The increase in compensation costs was made up of additional stock compensation expense of $0.8 million due to 2006 grants of restricted stock, an increase of $0.5 million for matching contributions to employees' retirement savings accounts and a 20% increase in the number of Canadian employees as compared to 2006. Operation of gas processing facilities built in 2005 and 2006 increased expense $1.7 million in 2006 compared to 2005.

Production expense for the U.S. increased $17.4 million in 2006 to $73.3 million as compared to 2005. Production expense for Texas increased $16.3 million for 2006 compared to 2005. Start-up of our Cowtown Plant and expansion of our Cowtown Pipeline System increased expense $8.4 million due in part to a net 8.8 Bcfe increase in production volumes. Remaining Texas production expense increased $7.9 million for 2006 when compared to 2005 as a result of larger operations including an increase in production and drilling operations that have required additional employees in our Texas field office. Production overhead expense for Texas in 2006 increased approximately $1.8 million, net of overhead recoveries, as a result of compensation for additional employees and an increase in office-related expenses, including rent. Lease operating expense increases of $4.9 million, net of approximately $1.0 million for clean-up of a saltwater spill that occurred in the second quarter, made up the remaining increase for 2006 Texas production expense when compared to 2005. Additional producing wells and increases in rates charged by third-parties were the primary causes of the $4.9 million increase in 2006 lease operating expense. The remaining expense increases included higher stock compensation expense for field employees of $0.6 million in 2006 as compared to 2005 and additional workover expense of approximately $0.4 million in our Michigan operating area.

Oil and gas production expense for 2005 was $71.2 million and $18.6 million higher than 2004 production expense. U.S. production expense increased $12.3 million, excluding expense for stock-based compensation expense, when compared to 2004 production expense. U.S. production expense for 2005 is also net of a $2.4 million reduction in Wyoming production expense as a result of the sale of most of our Wyoming properties in the third quarter of 2004. Operating expense for our Barnett Shale projects in the Fort Worth Basin increased nearly $7.9 million from 2004 to 2005. We had 36.6 net operated wells in operation at the end of 2005 compared to 3 net operated wells at the end of 2004. The growth of our operations increased lease operating expenses $4.7 million, which included $2.9 million for contract labor, equipment rentals and salt water disposal. Initial operating expenses for these items are typically greater when production begins as initial production includes high water production from the fracture stimulations. Operating costs for each well tends to decrease following the period of initial production; however, these expenses remained high for 2006 due to our drilling program in the Fort Worth Basin. Expense for the gathering and processing of our Barnett Shale natural gas production increased $3.2 million.

Production expense for our Michigan projects increased $5.4 million from 2004 production expense. Approximately $3.2 million of the increase for 2005 resulted from efforts to perform preventive equipment maintenance and repairs. Michigan environmental compliance and remediation expense increased almost $1.4 million for 2005. Salary and wages expense increased almost $0.6 million for personnel in Michigan, Indiana and Kentucky as a result of annual raises, the hiring of additional personnel and a small increase in 2005 bonuses compared to 2004.

Canadian production expense for 2005 increased $6.3 million from 2004 production expense, exclusive of stock-based compensation expense. We drilled 483 (259.1 net) wells during 2005 and net natural gas production increased 6.1 Bcf. Canadian production expense on a Mcfe-basis decreased $0.01/Mcfe. The decrease reflected additional improvement in the economies of scale for our Canadian operations.

Production and Ad Valorem 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 property values while production tax expense decreased as a result of lower prices in 2006 compared to 2005.

Production and ad valorem tax expense increased $2.5 million from 2004 to 2005 due primarily to higher prices for natural gas, crude oil and condensate as well as an increase in U.S. sales volumes. Canadian expense for production and ad valorem taxes was virtually unchanged from 2004 to 2005.

Depletion, Depreciation and Accretion

	Years Ended December 31,		
	2006	2005	2004
	(In thousands, except per unit amounts)		
Depletion	$65,669	$46,615	$34,530
Depreciation of other fixed assets	11,844	7,599	5,179
Accretion	1,287	999	982
Total depletion, depreciation and accretion	$78,800	$55,213	$40,691
Average depletion cost per Mcfe	$ 1.07	$ 0.91	$ 0.78

Our 2006 depletion expense increased $19.1 million from 2005 depletion expense. Our 2006 consolidated depletion rate increased $0.16 per Mcfe, and our production increased 9.8 Bcfe. The increase in our consolidated depletion rate was 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 $11.8 million and $4.2 million higher than 2005 depreciation expense of $7.6 million. The increase in depreciation is primarily the result of our new Cowtown Gas Plant, additions to our Cowtown Pipeline and new Canadian gas processing facilities.

Higher production volumes and an increase in our depletion rate for 2005 increased depletion expense $12.1 million from 2004 depletion expense. The $0.13 per Mcfe increase in our consolidated depletion rate was the result of a higher percentage increase for estimated future development costs as compared to proved reserve increases for 2005 as compared to 2004. Depreciation expense for 2005 increased $2.4 million when compared to 2004 expense. The increase is primarily the result of additional gas processing facilities in Canada and the U.S. as well as a full year's operation of the Cowtown Pipeline in the Barnett Shale.

General and Administrative Expense

General and administrative expense for 2006 was $24.9 million and an increase of $5.9 million from 2005 general and administrative expense of $19.0 million. 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 2006 grants of restricted stock, $1.5 million resulting from additional employees and annual raises and an increase 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.

For 2005, general and administrative expense was $19.0 million. The total was $6.0 million higher than 2004 general and administrative expense. During 2005, employee compensation expense increased approximately $5.6 million including nearly $1.0 million of expense for restricted stock granted to executives and employees during 2005. Additional management and administrative personnel increased compensation expense approximately $1.7 million. Bonuses paid to employees for 2005 were $1.9 million higher than 2004 and included $0.6 million for retention and hiring of key personnel. Annual raises and other compensation expenses, including the our contribution to employees' retirement accounts for 2005, increased general and administrative expense approximately $1.0 million while outside directors' compensation increased over $0.2 million including almost $0.1 million for vesting of restricted stock granted during 2005. Legal fees were $0.9 million higher due largely to work performed by outside attorneys on various corporate matters and litigation. These increases were partially offset by a $0.4 million decrease in contract labor expense and small decreases in various other expenses from 2004.

Interest Expense

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 and primarily the result of higher debt balances including the issuance of our $350 million in principal amount senior subordinated notes in March of 2006. Interest expense for 2006 included a prepayment penalty of $0.8 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 the 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.

Interest expense for 2005 was $21.7 million after interest capitalization of $1.1 million. The $6.1 million increase from 2004 was the result of higher debt balances that resulted from capital expenditures for our 2005 development, exploitation and exploration programs in Canada and Texas and was partially offset by a decrease in the average interest paid on our total debt balance. The decrease in our average interest rate was primarily the result of the 1.875% interest rate borne by our $150.0 million contingently convertible debentures issued in November 2004. Capitalized interest recorded in 2005 was associated with the construction of gathering and processing facilities in the Fort Worth Basin of Texas and in Canada.

Income Taxes

	Years Ended December 31,		
	2006	2005	2004
Income tax provision (in thousands)	$38,150	$40,702	$14,174
Effective tax rate	28.9%	31.8%	31.2%

Our income tax provision for 2006 was $38.1 million. 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 provision 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.

For 2005, our income tax provision was $40.7 million. Our U.S. income tax provision of $26.3 million was established using the statutory U.S. federal rate of 35%. The Canadian tax provision of approximately $14.3 million was accrued at a Canadian combined federal and provincial statutory rate of 33.6% and included a current tax provision of $0.5 million.

LIQUIDITY, CAPITAL RESOURCES AND FINANCIAL POSITION

Our statements of cash flows are summarized as follows:

	Years Ended December 31,		
	2006	2005	2004
		(In thousands)	
Net cash flow provided by operating activities	$220,615	$144,468	$84,847

Cash flows provided by operating activities in 2006 were $220.6 million and a $76.1 million increase from operating cash flow for 2005. The 53% increase in operating cash flow was primarily the result of a 19% increase in production, a 6% increase in realized product prices and more aggressive cash management.

Operating activities in 2005 generated $144.5 million of cash flows, or a 70% increase from 2004 operating cash flows. The primary factor in our increased operating cash flow was a $56.2 million increase in 2005 net income that reflected a 49% increase in our realized product prices and a 16% increase in 2005 production volumes.

	Years Ended December 31,		
	2006	2005	2004
		(In thousands)	
Cash flow used in investing activities:			
Purchases of property, plant and equipment	$(597,490)	$(329,495)	$(215,106)
Return of investment from equity affiliates	1,923	533	48
Proceeds from sale of properties	5,113	9,693	9,160
Net cash used for investing activities:	$(590,454)	$(319,269)	$(205,898)
Net working capital changes related to acquisition of property and equipment	$ (48,238)	$ (31,475)	$ (16,651)

Purchases of property, plant and equipment accounted for the most significant cash outlays for investing activities in each of the three years ended December 31, 2006, 2005 and 2004. We currently estimate that our spending for property, plant and equipment in 2007 will be approximately $610 million, of which we have allocated $502 million for drilling activities, $88 million for gathering and processing facilities, $18 million for acquisition of additional leasehold interests and $2 million for other property and equipment. 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 2006, 2005 and 2004 are as follows:

Property and Equipment Costs Incurred

	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, gathering and administrative	94,109	6,879	100,988
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, gathering and administrative	59,894	21,059	80,953
Total	$242,289	$118,680	$360,969
2004			
Proved acreage	$ 11,907	$ 2,942	$ 14,849
Unproved acreage	31,857	7,144	39,001
Development costs	45,213	71,094	116,307
Exploration costs	25,673	22,631	48,304
Gas processing, gathering and administrative	12,527	769	13,296
Total	$127,177	$104,580	$231,757

Capital costs incurred for 2006 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 northern Texas and our Canadian projects in the Western Sedimentary Basin in Alberta, Canada. In 2006, we drilled 123 (111.3 net) wells in northern Texas 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.

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 development 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 over $49.2 million.

Our 2004 capital expenditures for development, exploitation and exploration activities were focused in four areas. Expenditures for Canadian development, exploitation and exploration projects were approximately $104.6 million. Those expenditures continued exploration and development of our initial CBM projects as well as exploration of several additional CBM projects. Included in the $104.6 million of Canadian expenditures was $7.1 million for acquisition of additional acreage in several areas of Alberta. Expenditures for Texas development, exploitation and exploration activities were approximately $55.1 million, including approximately $29.3 million for additional acreage in north Texas. An additional $6.0 million was expended for the first phase of the Cowtown Pipeline. We spent approximately $31.5 million for continued development of our Michigan properties and an additional $2.1 million was spent on gathering and processing infrastructure. New wells and associated infrastructure in southern Indiana and northern Kentucky accounted for approximately $20.6 million of our expenditures for exploration and development activities. An additional $1.1 million was expended for the construction of plant and pipeline infrastructure in the Indiana/Kentucky area.

	Years Ended December 31,		
	2006	2005	2004
		(In thousands)	
Cash flow provided by financing activities:			
Issuance of debt	$ 694,682	$183,469	$ 511,091
Repayments of debt	(350,754)	(13,079)	(371,178)
Debt issuance costs	(9,213)	(745)	(8,023)
Proceeds from the exercise of stock options	19,689	2,894	2,499
Purchase of treasury stock	(384)	(95)	—
Payment for fractional shares	—	(18)	—
Minority interest contributions	7,291	—	—
Net cash provided by financing activities:	$ 361,311	$172,426	$ 134,389

Net cash provided by financing activities in 2006 was $361.3 million. On March 16, 2006, we issued $350 million in principal amount of Senior Subordinated Notes due in 2016. The Senior Subordinated Notes are unsecured, senior subordinated obligations and bear interest at an annual rate of 7.125% payable semiannually on April 1 and October 1 of each year. The terms and conditions of the Senior Subordinated Notes require us 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, transfers or sales of assets and mergers and consolidations. Based upon our 2006 year-end reserves, the indenture agreement limits us to $750 million of borrowing under our senior secured credit facility. At December 31, 2006, we were in compliance with such restrictions.

We used $70 million of the proceeds of the Senior Subordinated Notes to retire our second lien mortgage notes in March 2006. As a result of the early retirement, we were required to pay a premium of $0.8 million for early repayment of the notes. 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. For 2006, we have increased our borrowings under our U.S. and Canadian senior secured credit facilities approximately $133.1 million.

As of December 31, 2006, our borrowing base under our senior secured credit facility was $600 million, of which approximately $178 million was available for borrowing. The loan agreements for the senior 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, amortization, non-cash income and expense and exploration costs) to interest ratio. We were in compliance with all such covenants at December 31, 2006.

On February 9, 2007, we extended the senior secured credit facility to February 9, 2012 and to provide for revolving loans, swingline loans and letters of credit from time to time in an aggregate amount not to exceed the lesser of the borrowing base which is calculated based on several factors and is initially equal to $850 million. The borrowing base is subject to annual redeterminations and certain other redeterminations. The lenders have agreed to initial revolving credit commitments in an aggregate amount equal to $1.2 billion, and we have an option to increase the facility to $1.45 billion with the consent of the lenders. The lenders' commitments under the facility are allocated between U.S. and Canadian funds, with the U.S. funds available for borrowing by the Company and Canadian funds being available for borrowing by the Company's Canadian subsidiary, QRCI in U.S. or Canadian funds. 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 guaranteed by most of our domestic subsidiaries and are secured by, among other things, certain of our domestic subsidiaries' oil and gas properties. Canadian borrowings under the facility are secured by, among other things, QRCI's, our and certain of our domestic subsidiaries' oil and gas properties. 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. As of December 31, 2006, 2005 and 2004, our total capitalization was as follows:

	Years Ended December 31,		
	2006	2005	2004
		(In thousands)	
Long-term and short-term debt:			
Senior secured credit facility	$ 421,123	$357,788	$180,422
Senior subordinated notes	350,000	—	—
Convertible subordinated debentures	147,994	147,881	147,769
Second lien mortgage notes payable	—	70,000	70,000
Various loans	400	746	1,073
Deferred gain — fair value interest hedge	—	117	226
Total debt	919,517	576,532	399,490
Stockholders' equity	575,666	383,615	304,276
Total capitalization	$1,495,183	$960,147	$703,766

We believe that our capital resources are adequate to meet the requirements of our existing business. We anticipate that our 2007 capital expenditure budget of approximately $610 million will be funded by cash flow from operations, credit facility utilization and proceeds we expect to receive in connection with the anticipated sale to the public of approximately 19% of the limited partner interests of Quicksilver Gas Services LP ("QGSLP"), our subsidiary that will hold Cowtown Plant and the Cowtown Pipeline. Although QGSLP has filed a registration on Form S-1 relating to this offering, numerous factors, such as general market conditions and market conditions in the oil and gas industry in particular, could result in the offering not being completed. We may also consider the possible sale of assets and the possible issuance of debt or equity securities to fund our 2007 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 or other securities or a combination of two or more of those sources.

Financial Position

The following impacted our balance sheet as of December 31, 2006, as compared to our balance sheet as of December 31, 2005:

- A $343.0 million increase in our debt used to finance the development, exploitation and exploration of our oil and gas properties in 2006. In March 2006, we issued our $350 million in principal amount Senior Subordinated Notes.

- A $644.8 million increase in our net property, plant and equipment balances before 2006 depletion and depreciation resulting from capital expenditures for development, exploitation and exploration of our oil and gas properties.

- Our current portion of long-term debt has decreased by approximately $70.1 million. Our $70 million in principal amount of second lien mortgage notes were repaid in March 2006 using a portion of the proceeds from the issuance of our senior subordinated notes.

- A $63.5 million and $3.8 million increase in our current and deferred derivative assets, respectively, as well as a $40.6 million and $4.6 million decrease in our current and deferred derivative obligations, respectively, reflecting the relatively favorable pricing of our price collars as compared to the market price at year-end. Additionally, our current deferred income tax asset decreased by $14.6 million and our current deferred income tax liability increased $21.4 million as a result of changes in our derivative valuations.

Contractual Obligations and Commercial Commitments

Information regarding our contractual obligations (within the scope of Item 303(a)(5) of Regulations S-K), as well as scheduled interest obligations, at December 31, 2006 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	$ 921,523	$ 400	$421,123	$ —	$500,000
Scheduled Interest Obligations	281,619	28,541	83,250	55,500	114,328
Drilling Rig Contracts	112,345	51,128	61,217	—	—
Transportation Contracts	105,040	732	24,392	21,017	58,899
Purchase Obligations	5,923	5,923	—	—	—
Asset Retirement Obligations	25,206	149	178	119	24,760
Operating Lease Obligations	12,446	4,270	8,172	4	—
Total Obligations	$1,464,102	$91,143	$598,332	$76,640	$697,987

- *Long-Term Debt.* As of December 31, 2006, we had $421.1 million outstanding under our senior secured credit facility, $150 million of contingently convertible debentures (before discount), $350 million of senior subordinated notes and $0.4 million of other debt. Based upon our debt outstanding and interest rates in effect at December 31, 2006, we anticipate interest payments to be approximately $54.4 million in 2007. We expect to increase borrowings under our senior secured credit facility to fund our capital spending program throughout 2006. For each additional $10 million in borrowings, annual interest payments will increase by approximately $0.7 million. If the borrowing base under our senior secured credit facility were to be fully utilized by year-end 2007 at interest rates in effect at December 31, 2006, we estimate that interest payments would increase by approximately $6.2 million. If interest rates on our December 31, 2006 variable debt balance of $421.1 million increase or decrease by one percentage point, our annual pretax income will decrease or increase by $4.2 million.

- *Scheduled Interest Obligations.* As of December 31, 2006, we had scheduled interest payments in place for $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.

- *Drilling Contracts.* We lease drilling rigs from third parties for use in our development and exploration programs. Each of the contracts requires payment of the specified day rate for the entire lease term regardless of our utilization of the drilling rigs.

- *Transportation Contracts.* We entered into firm transportation contracts with pipelines during 2006. 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.

- *Purchase Obligations.* At December 31, 2006, we were under contract to purchase goods and services for completion of our gas processing plant units in Texas. Total remaining obligations for construction and completion of the gas processing units were $5.9 million including liabilities of $0.5 million recorded at December 31, 2006 for goods received and work performed.

- *Asset Retirement Obligations.* Our liabilities include the fair value, $25.1 million, of asset retirement obligations that result from the acquisition, construction or development and the normal operation of our long-lived assets.

- *Operating Leases.* We lease office buildings and other property under operating leases. Our operating lease obligations include $4.6 million of future lease payments to an affiliate of Mercury, which is owned by members of the Darden family.

We have the following commercial commitments as of December 31, 2006.

	Amounts of Commitments Expiration per Period				
Commercial Commitments	**Total Committed**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**More than 5 Years**
			(In thousands)		
Standby letters of credit	$559	$559	$—	$—	$—

- *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. All letters have an annual renewal option.

Forward-Looking Information

Certain statements contained in this 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 and crude oil prices;
- failure or delays in achieving expected production from natural gas and crude oil exploration and development projects;
- uncertainties inherent in estimates of natural gas and crude oil reserves and predicting natural gas and crude oil reservoir performance;
- effects of hedging natural gas and crude oil prices;
- competitive conditions in our industry;
- actions taken by third-party operators, processors and transporters;
- changes in the availability and cost of capital;
- delays in obtaining oil field 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 Financial Accounting Standards Board ("FASB") issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments — an amendment of FASB Statements No. 133 and 140*, in February 2006. SFAS No. 155 addresses accounting for beneficial interests in securitized financial instruments. The guidance allows fair value remeasurement for any hybrid financial instrument containing an embedded derivative that would otherwise require bifurcation and clarifies which interest-only and principal-only strips are not subject to SFAS No. 133. SFAS No. 155 also established a requirement to evaluate interests in securitized financial assets to identify any interests that are either freestanding derivatives or contain an embedded derivative requiring bifurcation. The statement is effective for all financial instruments issued or acquired after the beginning of the first fiscal year that begins after September 15, 2006. Management does not believe application of this statement will have a material impact on our financial position, results of operations or cash flows.

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. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. Management does not expect adoption of SFAS No. 157 will have a material impact on our financial position, results of operations or cash flows.

The FASB issued FASB Interpretation No. 48 ("FIN 48"), *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109*, in June 2006. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes*. FIN 48 defines a criterion that an individual tax position must meet for any part of the benefit of that position to be recognized in an enterprise's financial statements. FIN 48 also provides guidance on measurement, derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. We estimate that in the first quarter of 2007, we will recognize an adjustment to retained earnings of approximately $0.4 million to provide for additional deferred income tax liabilities.

On February 15, 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. The FASB believes the statement will improve financial reporting by providing companies the opportunity to mitigate volatility in reported earnings by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Use of the statement will expand the use of fair value measurements for accounting for financial instruments. We do not believe SFAS No. 159 did not have a material impact on our financial position or results of operations.

In September 2006, the SEC issued Staff Accounting Bulletin No. 108 ("SAB 108"). Due to diversity in practice among registrants, SAB 108 expresses the SEC staff's views regarding the process by which misstatements in financial statements are evaluated to determine whether financial statement restatement is necessary. SAB 108 is effective for fiscal years ending after November 15, 2006. SAB 108 did not have a material impact on our financial position or results from operations.

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, 2006 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, 2006, 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 management's assessment 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 28, 2007

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, 2006 and 2005 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, 2006. 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 the Quicksilver Resources Inc. and subsidiaries as of December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, 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, 2006, 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 28, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Fort Worth, Texas
February 28, 2007

QUICKSILVER RESOURCES INC.

CONSOLIDATED BALANCE SHEETS
As of December 31, 2006 and 2005
In thousands, except for share data

	2006	2005
ASSETS		
Current assets		
Cash and cash equivalents	$ 5,281	$ 14,318
Accounts receivable, net of allowance of $1,113 and $425	76,521	76,121
Current derivative assets	64,086	603
Current deferred income taxes	—	14,614
Other current assets	25,076	7,928
Total current assets	170,964	113,584
Investments in and advances to equity affiliates	7,434	8,353
Property, plant and equipment		
Oil and gas properties, full-cost method		
Subject to depletion	1,560,459	1,079,662
Unevaluated costs	191,665	132,090
Pipelines and processing facilities	225,771	139,554
Construction in progress	31,613	17,842
General property and equipment	17,183	14,086
Accumulated depletion and depreciation	(347,411)	(271,232)
Property, plant and equipment — net	1,679,280	1,112,002
Non-current derivative assets	3,753	—
Other assets	21,481	9,155
	$1,882,912	$1,243,094
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of long-term debt	$ 400	$ 70,493
Accounts payable	109,914	48,409
Accrued liabilities	67,697	52,656
Derivative obligations	—	40,632
Current deferred income taxes	21,378	—
Total current liabilities	199,389	212,190
Long-term liabilities		
Long-term debt	919,117	506,039
Non-current derivative obligations	—	4,631
Asset retirement obligations	25,058	20,891
Deferred income taxes	156,251	115,728
Commitments and contingencies (Note 13)	—	—
Total long-term liabilities	1,100,426	647,289
Minority interest	7,431	—
Stockholders' equity		
Preferred stock, $0.01 par value, 10,000,000 shares authorized, 0 and 1 share issued as of December 31, 2006 and 2005, respectively	—	—
Common stock, $0.01 par value, 200,000,000 and 100,000,000 shares authorized, and 80,181,593 and 78,650,110 shares issued as of December 31, 2006 and 2005, respectively	802	787
Paid in capital in excess of par value	238,063	211,843
Treasury stock of 2,579,671 and 2,571,069 shares as of December 31, 2006 and 2005, respectively	(10,737)	(10,353)
Accumulated other comprehensive income (loss)	60,099	(12,382)
Retained earnings	287,439	193,720
Total stockholders' equity	575,666	383,615
	$1,882,912	$1,243,094

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, 2006, 2005 and 2004
In thousands, except for per share data

	2006	2005	2004
Revenues			
Natural gas, NGL and crude oil sales	$386,540	$306,204	$177,173
Other revenue	3,822	4,244	2,556
Total revenues	390,362	310,448	179,729
Expenses			
Oil and gas production costs	95,176	71,204	52,629
Production and ad valorem taxes	15,619	15,068	12,557
Other operating costs	1,461	1,661	1,250
Depletion, depreciation and accretion	78,800	55,213	40,691
Provision for doubtful accounts	700	108	153
General and administrative	24,936	18,979	12,934
Total expenses	216,692	162,233	120,214
Income from equity affiliates	526	914	1,178
Operating income	174,196	149,129	60,693
Other income-net	(1,825)	(585)	(415)
Interest expense	44,061	21,740	15,662
Income from continuing operations before income taxes and minority interest	131,960	127,974	45,446
Income tax expense	38,150	40,702	14,174
Minority interest expense, net of income tax	91	—	—
Income from continuing operations	93,719	87,272	31,272
Discontinued operations — gain from discontinued drilling operations net of income tax of $86	—	162	—
Net income	$ 93,719	$ 87,434	$ 31,272
Other comprehensive income — net of taxes			
Net derivative settlements	(9,707)	26,892	26,875
Net change in derivative fair value	83,410	(49,743)	(5,174)
Foreign currency translation adjustment	(1,222)	3,707	2,744
Comprehensive income	$166,200	$ 68,290	$ 55,717
Basic net income per common share:			
Income from continuing operations	$ 1.22	$ 1.15	$ 0.42
Discontinued operations	—	—	—
Net income	$ 1.22	$ 1.15	$ 0.42
Diluted net income per common share:			
Income from continuing operations	$ 1.15	$ 1.08	$ 0.41
Discontinued operations	—	—	—
Net income	$ 1.15	$ 1.08	$ 0.41
Basic weighted average shares outstanding	76,707	75,716	74,654
Diluted weighted average shares outstanding	83,133	82,455	77,015

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, 2006, 2005 and 2004
In thousands, except for share data

	2006	2005	2004
Preferred stock, $0.01 par value, 10,000,000 shares authorized			
Balance at end of year: 0, 1 and 1 share issued at December 31, 2006, 2005 and 2004, respectively	$ —	$ —	$ —
Common stock, $0.01 par value, 200,000,000, 100,000,000 and 100,000,000 shares authorized			
Balance at beginning of year	787	778	768
Issuance of common stock — restricted stock	4	1	—
Issuance of common stock — stock options	11	8	10
Balance at end of year: 80,181,593, 78,650,110 and 77,752,151 shares issued at December 31, 2006, 2005 and 2004, respectively	802	787	778
Paid in capital in excess of par value			
Balance at beginning of year	211,843	200,690	193,998
Treasury stock reissued	—	—	147
Stock options exercised	19,678	2,885	2,302
Stock-based compensation expense recognized	6,542	1,732	—
Tax benefit related to stock options exercised	—	6,536	4,243
Balance at end of year	238,063	211,843	200,690
Treasury stock, at cost			
Balance at beginning of year	(10,353)	(10,258)	(10,299)
(Acquisition) reissuance of treasury stock, net	(384)	(95)	41
Balance at end of year: 2,579,671, 2,571,069 and 2,568,611 shares at December 31, 2006, 2005, and 2004, respectively	(10,737)	(10,353)	(10,258)
Accumulated other comprehensive loss			
Deferred losses on hedge derivatives			
Balance at beginning of year	(28,509)	(5,658)	(27,359)
Net derivative settlements	(9,707)	26,892	26,875
Net change in derivative fair value	83,410	(49,743)	(5,174)
Balance at end of year	45,194	(28,509)	(5,658)
Deferred foreign exchange adjustment			
Balance at beginning of year	16,127	12,420	9,676
Foreign currency translation adjustment	(1,222)	3,707	2,744
Balance at end of year	14,905	16,127	12,420
Total accumulated other comprehensive income (loss)	60,099	(12,382)	6,762
Retained earnings			
Balance at beginning of year	193,720	106,304	75,032
Payment for fractional shares	—	(18)	—
Net income	93,719	87,434	31,272
Balance at end of year	287,439	193,720	106,304
Total stockholders' equity	$575,666	$383,615	$304,276

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, 2006, 2005 and 2004
In thousands

	2006	2005	2004
Operating activities:			
Net income	$ 93,719	$ 87,434	$ 31,272
Charges and credits to net income not affecting cash			
Depletion, depreciation and amortization	78,800	55,213	40,691
Deferred income taxes	37,877	40,298	12,989
Non-cash compensation	6,546	1,732	—
Amortization of deferred loan costs	2,070	1,429	1,249
Income from equity affiliates	(526)	(914)	(1,178)
Minority interest expense	91	—	—
Non-cash (gain) loss from hedging activities	1	(462)	(786)
Provision for doubtful accounts	700	108	153
Other	414	157	91
Changes in assets and liabilities			
Accounts receivable	(1,100)	(38,192)	(11,715)
Inventory, prepaid expenses and other assets	(26,066)	(1,919)	4,413
Accounts payable	15,193	1,963	2,220
Accrued and other liabilities	12,896	(2,379)	5,448
Net cash provided by operating activities	220,615	144,468	84,847
Investing activities:			
Purchases of property, plant and equipment	(597,490)	(329,495)	(215,106)
Return of investment from equity affiliates	1,923	533	48
Proceeds from sale of properties	5,113	9,693	9,160
Net cash used for investing activities	(590,454)	(319,269)	(205,898)
Financing activities:			
Issuance of debt	694,682	183,469	511,091
Repayments of debt	(350,754)	(13,079)	(371,178)
Debt issuance costs	(9,213)	(745)	(8,023)
Proceeds from exercise of stock options	19,689	2,894	2,499
Purchase of treasury stock	(384)	(95)	—
Payment for fractional shares	—	(18)	—
Minority interest contributions	7,291	—	—
Net cash provided by financing activities	361,311	172,426	134,389
Effect of exchange rates on cash	(509)	746	(1,507)
Net (decrease) increase in cash and equivalents	(9,037)	(1,629)	11,831
Cash and equivalents at beginning of period	14,318	15,947	4,116
Cash and equivalents at end of period	$ 5,281	$ 14,318	$ 15,947

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

1. NATURE OF OPERATIONS

Quicksilver Resources Inc. ("Quicksilver" or the "Company") is an independent oil and gas company incorporated in the state of Delaware and headquartered in Fort Worth, Texas. Quicksilver engages in the development, exploitation, exploration, acquisition and production and sale of natural gas, NGLs and crude oil as well as the marketing, processing and transmission of natural gas. Substantial portions of Quicksilver's reserves are located in Michigan, Texas, Indiana, Kentucky, the Rocky Mountains and Alberta, Canada. Quicksilver has U.S. offices in Gaylord, Michigan; Corydon, Indiana; Cut Bank, Montana; Granbury, Texas and a Canadian subsidiary, Quicksilver Resources Canada Inc. ("QRCI") located in Calgary, Alberta.

Quicksilver's results of operations are largely dependent on the difference between the prices received for its natural gas and crude oil products and the cost to find, develop, produce and market such resources. Natural gas 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

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 after elimination of all significant inter-company balances and transactions. 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 pro-rata share of oil and gas joint ventures. All significant inter-company transactions are eliminated.

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 and crude oil reserves used to compute depletion of natural gas and crude oil properties and the related present value of estimated future net cash flows therefrom (see Supplemental Information found in Note 23), 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.

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 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 2006 and 2005, one purchaser accounted for approximately 10% of the Company's total consolidated natural gas, NGL and crude oil sales. Two purchasers accounted for approximately 15% and 14% of the Company's total consolidated 2004 sales.

Hedging

The Company enters into financial derivative instruments to hedge price risk for its natural gas and crude oil sales and interest rate risk. Hedging is 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 4). 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. Gains and losses that qualify as hedges are 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 or interest rates. Ineffective portions of hedges, if any, are recognized currently in earnings.

The Company's long-term contracts for delivery of 25 MMcfd and 10 MMcfd at a floor of $2.49 and $2.47 per Mcf, respectively, through March 2009 are not considered derivatives but have been designated as normal sales contracts under SFAS No. 133. Approximately 31.2 MMcfd of the Company's natural gas production was sold under these contracts during 2006. The remaining volumes sold under these contracts were third-party volumes controlled by the Company.

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.

Property, Plant, and Equipment

The Company follows the full cost method of accounting for oil and gas properties. Accordingly, all costs associated with the acquisition, exploration and development of oil and gas properties, including costs of undeveloped leasehold, geological and geophysical expenses, dry holes, leasehold equipment and overhead charges directly related to acquisition, exploration and development activities 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. Natural gas 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 net of deferred tax 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 natural gas and crude oil revenue, so that the Company recognizes sales revenue on all natural gas 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, 2006 and 2005, the Company's aggregate natural gas and crude oil imbalances were not material to its consolidated financial statements.

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, the Company's Canadian subsidiary, 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

Minority interest in consolidated subsidiaries held by third parties is subject to provisions for redemption outside of the Company's control and is accounted for as mezzanine equity. These interests are recorded at fair value at the date of issue and will be subsequently evaluated to determine the redemption value at each balance sheet date.

At December 31, 2006, the carrying amounts of these interests exceed their redemption amounts; therefore no adjustments to the carrying amounts have been recorded.

Foreign Currency Translation

The Company's Canadian subsidiary, QRCI, uses the Canadian dollar as its functional currency. All balance sheet accounts of Canadian operations are translated into U.S. dollars at the year-end rate of exchange and statement of income items are translated at the weighted average exchange rates for the year. The resulting translation adjustments are made directly to a separate 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 net income or loss per common share is computed by dividing the net income or loss 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,		
	2006	2005	2004
	(In thousands, except per share data)		
Income from continuing operations	$93,719	$87,272	$31,272
Income from discontinued operations, net of income taxes	—	162	—
Net income	93,719	87,434	31,272
Impact of assumed conversions — interest on 1.875% contingently convertible debentures, net of income taxes	1,901	1,901	317
Income available to stockholders assuming conversion of contingently convertible debentures	$95,620	$89,335	$31,589
Weighted average common shares — basic	76,707	75,716	74,654
Effect of dilutive securities:			
Employee stock options	1,110	1,718	1,544
Employee stock awards	408	113	—
Contingently convertible debentures	4,908	4,908	817
Weighted average common shares — diluted	83,133	82,455	77,015
Basic:			
Income from continuing operations	$ 1.22	$ 1.15	$ 0.42
Income from discontinued operations, net of income taxes	—	—	—
Net income	$ 1.22	$ 1.15	$ 0.42
Diluted:			
Income from continuing operations	$ 1.15	$ 1.08	$ 0.41
Income from discontinued operations, net of income taxes	—	—	—
Net income	$ 1.15	$ 1.08	$ 0.41

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 123(R)"). This statement requires the cost resulting from all share-based payment transactions be recognized in the financial statements at their fair value on the grant date. SFAS 123(R) was adopted by the Company 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. 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 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 requisite service is rendered after January 1, 2006. The compensation cost for unvested stock option awards granted before adoption of SFAS 123(R) shall be 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. The adoption of the statement reduced income before income taxes by $0.7 million and reduced 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 were each $0.01 lower as a result of SFAS No. 123(R) adoption in 2006. At December 31, 2006, the Company had $0.4 million of expense remaining in unrecognized compensation cost 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 2006 had total compensation cost of $18.3 million at the time of grant. During 2006, the Company recognized $5.8 million of expense for vesting of restricted stock and stock units. Total unvested compensation cost was $14.2 million at December 31, 2006 with a weighted average remaining vesting period of 1.3 years.

Prior to the adoption of SFAS 123(R), the Company 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 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 123(R). As a result of the Company's net operating losses, the excess tax benefits that would otherwise be available to reduce income taxes payable have the effect of increasing the Company's net operating loss carry forwards. Accordingly, because the Company is not able to realize these excess tax benefits, such benefits have not been recognized in the condensed consolidated statement of cash flows for the year ended December 31, 2006.

The following table reflects pro forma net income and the associated earnings per share as if the Company had applied the fair value recognition provisions of SFAS No. 123, *Accounting for Stock-based Compensation*, to stock-based employee compensation.

	Years Ended December 31,	
	2005	2004
	(In thousands, except per share data)	
Net income	$ 87,434	$31,272
Deduct: Total stock-based compensation expense determined under fair value-based method for stock option awards, net of related income tax effect	(11,359)	(4,524)
Pro forma net income	76,075	26,748
Impact of assumed conversions — 1.875% contingently convertible debentures, net of income taxes	1,901	317
Pro forma net income available to stockholders assuming conversion of contingently convertible debentures	$ 77,976	$27,065
As reported		
Basic net income per common share	$ 1.15	$ 0.42
Diluted net income per common share	$ 1.08	$ 0.41
Pro forma		
Basic net income per common share	$ 1.00	$ 0.36
Diluted net income per common share	$ 0.95	$ 0.35

Additional description and disclosure of the Company's stock-based compensation plans and activities is included in Note 16.

Recently Issued Accounting Standards

The Financial Accounting Standards Board ("FASB") issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments — an amendment of FASB Statements No. 133 and 140,* in February 2006. SFAS No. 155 addresses accounting for beneficial interests in securitized financial instruments. The guidance allows fair value remeasurement for any hybrid financial instrument containing an embedded derivative that would otherwise require bifurcation and clarifies which interest-only and principal-only strips are not subject to SFAS No. 133. SFAS No. 155 also established a requirement to evaluate interests in securitized financial assets to identify any interests that are either freestanding derivatives or contain an embedded derivative requiring bifurcation. The statement is effective for all financial instruments issued or acquired after the beginning of the first fiscal year that begins after September 15, 2006. Quicksilver's management does not believe application of this Statement will have a material impact on the Company's financial position, results of operations or cash flows.

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. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. Company management does not expect adoption of SFAS No. 157 will have a material impact on the Company's financial position, results of operations or cash flows.

The FASB issued FASB Interpretation No. 48 ("FIN 48"), *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109,* in June 2006. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* FIN 48 defines a criterion that an individual tax position must meet for any part of the benefit of that position to be recognized in an enterprise's financial statements. FIN 48 also provides guidance on measurement, derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company's management has evaluated the impact of FIN 48 and expects to record an adjustment to retained earnings of approximately $0.4 million to provide for additional deferred income tax liabilities.

On February 15, 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. The FASB believes the statement will improve financial reporting by providing companies the opportunity to mitigate volatility in reported earnings by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Use of the statement will expand the use of fair value measurements for accounting for financial instruments. The Company does not believe SFAS No. 159 will have a material impact on its financial position, results of operations or cash flows.

In September 2006, the Securities and Exchange Commission ("SEC") issued Staff Accounting Bulletin No. 108 ("SAB 108"). Due to diversity in practice among registrants, SAB 108 expresses the SEC staff's views regarding the process by which misstatements in financial statements are evaluated to determine whether financial statement restatement is necessary. SAB 108 is effective for fiscal years ending after November 15, 2006. SAB 108 did not have a material impact on the Company's financial position, results of operations or cash flows.

3. HEDGING

The Company hedges a portion of its equity production of natural gas and crude oil 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.

During 2006, the Company entered into fixed price firm natural gas sale commitments and hedged these commitments with financial price swaps that extend through March 2007. The financial price swaps qualify as fair value hedges.

On September 11, 2003, the Company entered into a fair value interest swap covering $40 million of its fixed rate 2003 Second Mortgage Notes. The swap converted the debt's 7.5% fixed rate to a floating six-month LIBOR base rate plus 4.07% through the termination of the notes. In January 2004, the swap position was cancelled and the Company received a cash settlement of $0.3 million that was recognized during the original term of the hedge until the associated 2003 Second Mortgage Notes were retired in March 2006.

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, 2005 resulted from the decrease in market prices for natural gas and crude oil. The change in fair value of all cash flow hedges was reflected in accumulated other comprehensive income, net of deferred tax effects. Natural gas and crude oil derivative assets and liabilities reflected as current in the December 31, 2006 balance sheet represent the estimated fair value of contract settlements scheduled to occur over the subsequent twelve-month period based on market prices for natural gas and crude oil as of the balance sheet date. These settlement amounts are not due and payable until the monthly period in which the related underlying hedged gas or oil sales transaction occurs. Settlement of the underlying hedged transactions occurs in the following 25 to 60 days.

The estimated fair values of all derivatives and the associated fixed price firm sale commitments of the Company as of December 31, 2006 and 2005 are provided below. The associated carrying values of these swaps 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,	
	2006	2005
	(In thousands)	
Derivative assets:		
Fixed price sale commitments	$ 53	$ 638
Natural gas basis swaps	159	—
Crude oil financial collars	689	—
Natural gas financial swaps	1,009	—
Natural gas financial collars	65,982	—
	$67,892	$ 638
Derivative liabilities:		
Natural gas financial collars	$ —	$44,480
Floating price natural gas financial swaps	53	463
Crude oil financial collars	—	320
Fixed price sale commitments	—	35
	$ 53	$45,298

The fair value of all natural gas and crude derivatives and firm sale and purchase commitments accounted for as hedges as of December 31, 2006 and 2005 was estimated based on market prices of natural gas and crude oil for the periods covered by the derivatives. The net differential between the prices in each derivative and market prices for future periods, as adjusted for estimated basis, has been applied 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. The fair value of the interest rate swap was based upon counterparty estimates of the fair value of such swaps. As a result, the fair value of the Company's derivatives and commitments does not necessarily represent the value a third party would pay or expect to receive to assume the Company's contract positions. Derivative assets of $64.1 million have been classified as current at December 31, 2006 based on the maturity of the derivative instruments, resulting in $42.7 million of after-tax gains to be reclassified from accumulated other comprehensive income in 2007.

4. 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 natural gas and crude oil commodity prices. 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 enters into long-term sales contracts and financial derivative contracts to hedge its exposure to commodity price risk associated with anticipated future natural gas, crude oil and NGL production. These contracts can include physical sales contracts and financial derivatives including price ceilings and floors, no-cost collars and fixed price swaps. As of December 31, 2006, Quicksilver sells approximately 10 MMcfd and 25 MMcfd of natural gas under long-term contracts with floors of $2.47 per Mcf and $2.49 per Mcf, respectively, through March 2009, respectively. Approximately 31.2 MMcfd of the Company's natural gas production was sold under these contracts during 2006. The remaining volumes sold under these contracts were third-party volumes controlled by the Company. These contracts are not considered derivatives, but rather have been designated as normal sales contracts under SFAS No. 133.

Natural gas price collars have been put in place to hedge 2007 anticipated production of approximately 123 MMcfd. Additionally, the Company has used price collar agreements to hedge approximately 1,250 Bbld of its anticipated crude oil, condensate and NGL production in 2007. Anticipated natural gas production of approximately 40 MMcfd has been hedged for the first quarter of 2008 using price collars and an additional 40 MMcfd of natural gas production has been hedged using fixed price swaps. These financial derivative contracts allow the Company to benefit from significant predictability of its natural gas and crude oil revenues.

The following table summarizes the Company's open financial derivative positions as of December 31, 2006 related to its natural gas 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	$ 609
Gas	Swap	Jan 2008-Dec 2008	7,500 Mcfd	8.13	183
Gas	Swap	Jan 2008-Dec 2008	5,000 Mcfd	8.14	139
Gas	Swap	Jan 2008-Dec 2008	2,500 Mcfd	8.15	78
Gas	Collar	Jan 2007-Apr 2007	10,000 Mcfd	7.50 - 11.00	1,641
Gas	Collar	Jan 2007-Apr 2007	10,000 Mcfd	7.50 - 11.15	1,644
Gas	Collar	Jan 2007-Mar 2007	10,000 Mcfd	7.50 - 9.65	1,257
Gas	Collar	Jan 2007-Mar 2007	10,000 Mcfd	8.00 - 14.72	1,593
Gas	Collar	Jan 2007-Mar 2007	10,000 Mcfd	8.50 - 11.35	2,095
Gas	Collar	Jan 2007-Mar 2007	10,000 Mcfd	8.50 - 11.50	2,101
Gas	Collar	Jan 2007-Mar 2007	20,000 Mcfd	8.00 - 15.00	3,370
Gas	Collar	Jan 2007-Dec 2007	10,000 Mcfd	9.00 - 12.10	8,258
Gas	Collar	Jan 2007-Dec 2007	20,000 Mcfd	9.00 - 12.10	16,515
Gas	Collar	Apr 2007-Oct 2007	10,000 Mcfd	7.50 - 11.50	2,455
Gas	Collar	Apr 2007-Oct 2007	10,000 Mcfd	7.50 - 11.75	2,488
Gas	Collar	Apr 2007-Oct 2007	5,000 Mcfd	7.50 - 11.78	1,248
Gas	Collar	Apr 2007-Oct 2007	5,000 Mcfd	7.50 - 11.80	1,259
Gas	Collar	May 2007-Dec 2007	10,000 Mcfd	7.00 - 9.15	1,724
Gas	Collar	May 2007-Dec 2007	10,000 Mcfd	8.00 - 11.20	3,011
Gas	Collar	Apr 2007-Mar 2008	10,000 Mcfd	9.00 - 12.00	6,477
Gas	Collar	Apr 2007-Mar 2008	10,000 Mcfd	9.00 - 12.05	6,504
Gas	Collar	Nov 2007-Mar 2008	10,000 Mcfd	8.00 - 15.00	1,120
Gas	Collar	Nov 2007-Mar 2008	10,000 Mcfd	8.00 - 15.65	1,222
Oil	Collar	Oct 2006-Jun 2007	1,000 Bbld	50.00 - 85.85	23
Oil	Collar	Oct 2006-Jun 2007	1,000 Bbld	50.00 - 85.85	23
Oil	Collar	Jul 2007-Dec 2007	500 Bbld	70.00 - 91.10	643
Gas	Basis	Jan 2007	1,935 Mcfd		145
Gas	Basis	Jan 2007-May 2007	3,973 Mcfd		14
				Total	$67,839

Utilization of the Company's financial hedging program may result in natural gas and crude oil realized prices that vary from actual prices that the Company receives from the sale of natural gas and crude oil. As a result of the hedging programs, revenues from production in 2006, 2005 and 2004 were $15.5 million higher, and $41.8 million and $43.9 million lower, respectively, than if the hedging programs had not been in effect.

The Company entered into various financial contracts to hedge exposure to commodity price risk associated with future contractual natural gas sales with financial swaps. As the natural gas sales contracts meet the definition of a firm commitment, the associated financial price swaps qualify as fair value hedges. Marketing revenues were $0.2 million lower and $0.1 million and $0.5 million higher as a result of its hedging activities in 2006, 2005 and 2004, respectively.

The following table summarizes our open financial swap positions and hedged firm commitments as of December 31, 2006 related to natural gas marketing.

Contract Period	Volume	Weighted Avg Price per Mcf	Fair Value (In thousands)
Natural Gas Sales Contracts			
Jan 2007 — Mar 2007	30,000 Mcf	$8.05	$ 53
Natural Gas Financial Derivatives			
Jan 2007 — Mar 2007	30,000 Mcf	Floating Price	(53)
Total-net			$ —

Hedge ineffectiveness resulted in $0.1 million of net losses, $0.1 million of net gains and $0.1 million of net losses in 2006, 2005 and 2004, respectively.

Commodity price fluctuations affect the remaining natural gas and crude oil volumes as well as the Company's NGL volumes. Natural gas volumes of 16.5 MMcfd of natural gas are committed at market price through September 2008. During 2006, approximately 8.9 MMcfd of Quicksilver's natural gas production was sold under these contracts. Approximately 7.6 MMcfd sold under these contracts were third-party volumes controlled by the Company.

The fair values of fixed price and floating price natural gas and crude oil derivatives and associated firm commitments as of December 31, 2006 and 2005 were estimated based on market prices of natural gas and crude oil for the periods covered by the contracts. The net differential between the prices in each contract and market prices for future periods, as adjusted for estimated basis, has been applied 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. As a result, the natural gas and crude oil financial swap and firm commitment fair value does not necessarily represent the value a third party would pay or expect to receive to assume the Company's contract positions.

Interest Rate Risk

The Company manages its exposure associated with interest rates by entering into interest rate swaps. As of December 31, 2006 and 2005, the Company had no interest rate swaps in effect. As of December 31, 2004, the interest payments for $75.0 million notional variable-rate debt were hedged with an interest rate swap that converted a floating three-month LIBOR base to a 3.74% fixed-rate through March 31, 2005. The liability associated with the swap was $0.2 million at December 31, 2004.

On September 10, 2003, the Company entered into an interest rate swap to hedge the $40.0 million of fixed-rate second lien notes issued on June 27, 2003. The swap converted the debt's 7.5% fixed-rate debt to a floating six-month LIBOR base. In January 2004, the swap position was cancelled and the Company received a cash settlement of $0.3 million that was recognized over the original term of the swap until the second lien mortgage notes were retired in March 2006. Upon retirement of the notes, the remaining portion of the deferred gain was recognized.

Credit Risk

Credit risk is the risk of loss as a result of non-performance by counterparties of their contractual obligations. The Company sells a portion of its natural gas production directly under long-term contracts, and the remainder of its natural gas and crude oil is sold to large trading companies and energy marketing companies, refineries and other users of petroleum products at spot or short-term contracts. Quicksilver also enters into hedge derivatives with financial counterparties. The Company monitors its exposure to counterparties by reviewing credit ratings, financial statements and credit service reports. Exposure levels are limited and parental guarantees are required according to

Company policy. 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. In this manner, the Company reduces credit risk.

While Quicksilver follows its credit policies at the time it enters into sales contracts, the credit-worthiness of counter parties could change over time. The credit ratings of the parent companies of the two counter parties to the Company's long-term gas contracts were downgraded in early 2003 and remain 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. In 2005, foreign currency transaction losses of $0.1 million were recorded as a result of losses in the Canadian-$ value of U.S.-$ bank balances in each of those years. During October and November 2004, Quicksilver loaned QRCI approximately $11.4 million. To reduce its exposure to exchange rate risk, QRCI entered into a forward contract that fixed the Canadian-to-US exchange rate. The balance of the loan was repaid at the end of November and upon settlement of the forward contract, QRCI recognized a gain of $0.2 million.

5. ACCOUNTS RECEIVABLE

Accounts receivable consist of the following:

	As of December 31,	
	2006	2005
	(In thousands)	
Accrued production receivables	$47,036	$48,392
Joint interest receivables	29,155	26,430
Other receivables	1,443	1,724
Allowance for bad debts	(1,113)	(425)
	$76,521	$76,121

6. OTHER CURRENT ASSETS

Other current assets consist of the following:

	As of December 31,	
	2006	2005
	(In thousands)	
Parts and supplies	$22,593	$6,137
Prepaid expenses and deposits	2,483	1,791
	$25,076	$7,928

7. PROPERTY, PLANT AND EQUIPMENT

Property and equipment consist of the following:

	As of December 31,	
	2006	2005
	(In thousands)	
Oil and gas properties		
Subject to depletion	$1,560,459	$1,079,662
Unevaluated costs	191,665	132,090
Accumulated depletion	(308,065)	(243,094)
Net oil and gas properties	1,444,059	968,658
Other equipment		
Pipelines and processing facilities	225,771	139,554
General properties	17,183	14,086
Construction in progress	31,613	17,842
Accumulated depreciation	(39,346)	(28,138)
Net other property and equipment	235,221	143,344
Property and equipment, net of accumulated depreciation and depletion	$1,679,280	$1,112,002

Unevaluated Natural Gas and Crude Oil Properties Excluded From Depletion

Under full cost accounting, the Company may exclude certain unevaluated 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, 2006 and 2005 and the year in which they were incurred as follows:

	December 31, 2006 Costs Incurred During					December 31, 2005 Costs Incurred During				
	2006	2005	2004	Prior	Total	2005	2004	2003	Prior	Total
	(In thousands)					(In thousands)				
Acquisition costs	$46,512	$42,030	$34,994	$28,181	$151,717	$44,069	$39,711	$27,168	$4,641	$115,589
Exploration costs	23,569	7,563	8,658	158	39,948	7,559	8,658	284	—	16,501
Total	$70,081	$49,593	$43,652	$28,339	$191,665	$51,628	$48,369	$27,452	$4,641	$132,090

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, 2006, approximately $150.8 million and $34.4 million of the total unevaluated costs of $191.7 million 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 this activity should be completed over the next two to three years.

Capitalized Costs

Capitalized overhead costs that directly relate to exploration and development activities were $3.2 million, $5.3 million and $3.1 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Depletion per Mcfe was $1.07, $0.91 and $0.78 for the years ended December 31, 2006, 2005 and 2004, respectively.

8. OTHER ASSETS

Other assets consist of the following:

	As of December 31,	
	2006	2005
	(In thousands)	
Deferred financing costs	$23,532	$15,763
Less accumulated amortization	(7,946)	(7,320)
Net deferred financing costs	15,586	8,443
Other	5,895	712
	$21,481	$ 9,155

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

9. ACCRUED LIABILITIES

Accrued liabilities consist of the following:

	As of December 31,	
	2006	2005
	(In thousands)	
Accrued capital expenditures	$33,959	$32,033
Prepayments from partners	6,642	2,110
Accrued operating expenses	7,527	8,143
Revenue payable	6,174	5,288
Accrued production and property taxes	1,630	877
Accrued product purchases	2,783	1,192
Interest payable	7,494	1,355
Environmental liabilities	749	1,301
Other	739	357
	$67,697	$52,656

10. NOTES PAYABLE AND LONG-TERM DEBT

Long-term debt consists of the following:

	As of December 31, 2006	As of December 31, 2005
	(In thousands)	
Senior secured credit facility	$421,123	$357,788
Senior subordinated notes	350,000	—
Contingently convertible debentures, net of unamortized discount of $2,006 and $2,119	147,994	147,881
Second lien mortgage notes payable	—	70,000
Other loans	400	746
Deferred gain — fair value interest hedge	—	117
	919,517	576,532
Less current maturities	(400)	(70,493)
	$919,117	$506,039

Maturities are as follows, in thousands of dollars:

2007	$ 400
2008	—
2009	421,123
2010	—
2011	—
Thereafter	500,000
	$921,523

On July 28, 2004, the Company extended its senior secured credit facility to July 28, 2009 to provide for revolving loans and letters of credit from time to time in an aggregate amount not to exceed the lesser of the borrowing base or $600 million. At December 31, 2006, the current borrowing base was $600 million. The borrowing base was subject to annual redeterminations and certain other redeterminations, based upon several factors. The lenders' commitments under the facility were allocated between U.S. and Canadian commitments, with the U.S. commitment available for borrowings by the Company and the Canadian commitment available for borrowings by the Company's Canadian subsidiary, QRCI. U.S. borrowings under the facility were guaranteed by most of Quicksilver's domestic subsidiaries and are secured by Quicksilver's and certain of its subsidiaries' oil and gas properties. Canadian borrowings under the facility were secured by QRCI's oil and gas properties. 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. Based upon the Company's 2006 year-end reserves, the Company is limited under the indenture agreement to $750 million of borrowing under our senior secured credit facility. The Company was in compliance with all such covenants at December 31, 2006. The senior credit facility was also used to issue letters of credit. At December 31, 2006, the Company had $0.6 million in letters of credit and approximately $178 million available under the senior revolving credit facility.

On February 9, 2007, the Company extended its senior secured credit facility to February 9, 2012 and to provide for revolving loans, swingline loans and letters of credit from time to time in an aggregate amount not to exceed the lesser of the borrowing base which is calculated based on several factors and is initially equal to

$850 million. The borrowing base is subject to annual redeterminations and certain other redeterminations. The lenders have agreed to initial revolving credit commitments in an aggregate amount equal to $1.2 billion, and the Company has an option to increase the facility to $1.45 billion with the consent of the lenders. The lenders' commitments under the facility are allocated between U.S. and Canadian funds, with the U.S. funds available for borrowing by the Company and Canadian funds being available for borrowing by the Company's Canadian subsidiary, QRCI in U.S. or Canadian funds. 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 guaranteed by most of Quicksilver's domestic subsidiaries and are secured by, among other things Quicksilver's and certain of its domestic subsidiaries' oil and gas properties. Canadian borrowings under the facility are secured by, among other things, QRCI's, Quicksilver's and certain of Quicksilver's domestic subsidiaries' oil and gas properties. 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.

On March 16, 2006, the Company issued $350 million in principal amount of Senior Subordinated Notes due 2016 ("Senior Subordinated Notes"). The Senior Subordinated Notes are unsecured, senior subordinated obligations of the Company and bear interest at an annual rate of 7.125% payable semiannually on April 1 and October 1 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, 2006, the Company was in compliance with such covenants. Under the indenture, the maximum amount of borrowings from the senior credit facility was $750 million. At December 31, 2006, the fair value of the $350 million in principal amount of Senior Subordinated Notes was $342.1 million.

In March 2006, the Company used $70 million of the proceeds from the issuance of the Senior Subordinated Notes to retire the second lien mortgage notes. As a result of the repayment, the Company recognized additional interest expense of $1.0 million consisting of a prepayment premium of $0.8 million and a charge of $0.3 million for associated unamortized deferred financing costs, partially offset by recognition of an associated deferred hedging gain of $0.1 million.

On November 1, 2004, the Company sold $150 million $1.875% convertible subordinated debentures due November 1, 2024, which are contingently convertible into shares of Quicksilver's common stock (subject to adjustment). As of December 31, 2006 and 2005, the debentures were convertible into 4,908,128 shares of Quicksilver's common stock. Each $1,000 debenture was issued at 98.5% of par and bears interest at an annual rate of 1.875% payable semi-annually on May 1 and November 1 of each year. 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 32.7209 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 $36.67 (120% of the conversion price per share) for at least 20 trading days during the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter. Upon conversion, the Company has the option to deliver in lieu of Quicksilver common stock, cash or a combination of cash and Quicksilver common stock. At December 31, 2006, the fair value of the $150 million in principal amount of contingently convertible debentures was $207.4 million.

11. ASSET RETIREMENT OBLIGATIONS

The Company records the fair value of the liability for asset retirement obligations in the period in which it is 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, 2006, 2005 and 2004, 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, 2005 through December 31, 2006.

	2006	2005
	(In thousands)	
Beginning asset retirement obligations	$20,965	$18,471
Additional liability incurred	5,399	2,123
Accretion expense	1,287	999
Change in estimates	30	(581)
Sale of properties	(2,439)	(109)
Asset retirement costs incurred	(174)	(125)
Loss on settlement of liability	158	39
Currency translation adjustment	(20)	148
Ending asset retirement obligations	$25,206	$20,965

During the years ended December 31, 2006, 2005 and 2004, accretion expense was recognized and included in depletion, depreciation and accretion expense reported in the statement of income for the year. Asset retirement obligations at December 31, 2006 and 2005 are $25.2 million and $21.0 million, respectively, of which $0.2 million and $0.1 million, respectively, was classified as current.

12. 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 that will be in effect in the years in which the temporary differences are expected to reverse. For years prior to 2004, the Company had accrued no U.S. deferred income taxes on QRCI's undistributed earnings or on the related translation adjustments pursuant to FAS No. 109, *Accounting for Income Taxes*, and APB No. 23, *Accounting for Income Taxes — Special Areas* as the Company expected that QRCI's undistributed earnings would be permanently reinvested for use in the development of its oil and gas reserves. In July 2004, however, a dividend distribution of $86.5 million was made by QRCI to Quicksilver. The distribution represented the repayment of Quicksilver's capital contributions that had been made to QRCI for the period January 1, 2001 through July 27, 2004 in the amount of $114.4 million, Canadian. This dividend was reinvested in the U.S. under a qualified domestic reinvestment plan as defined under Internal Revenue Code Section 965(b)(4). The funds were used for capital expenditures in the Barnett Shale exploration and development program. After application of the 85% dividend exclusion on estimated accumulated earnings and profits of approximately $15.5 million, a current U.S. federal income tax of approximately $0.8 million was accrued on this dividend distribution in 2004 and paid in 2005. No other deferred taxes have been accrued on QRCI's undistributed earnings, and the Company continues to expect that the balance of QRCI's undistributed earnings will be permanently reinvested for use in the development of its 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 and, therefore, the provisions of SFAS No. 109, *Accounting for Income Taxes* ("SFAS 109"), regarding the recognition of deferred taxes apply to the new margin tax. In accordance with SFAS 109, the effect on deferred tax assets and liabilities of a change in tax law should be included in tax expense attributable to continuing operations in the period that includes the enactment date. Therefore, the Company has recalculated its deferred tax assets and liabilities for Texas based upon the new margin tax and recorded a deferred tax provision of $1.6 million for the Texas margin tax in 2006.

During the third quarter of 2006, the Company was notified that IRS audits of Terra Energy Ltd. ("Terra"), a wholly-owned subsidiary of Quicksilver, were closed for all years prior to its acquisition by the Company in 2000. As a result, the Company reversed a $0.9 million deferred tax liability for items associated with differences in book basis and tax basis for Terra prior to its acquisition.

Tax rate reductions were enacted during 2006 by the Canadian federal government as well as several provinces. As required by SFAS 109, the Company's Canadian deferred income tax balances were revalued to reflect the changes in these tax rates. The Company recorded a $3.8 million income tax benefit in the second quarter of 2006 as a result of the Canadian rate reductions.

Significant components of the Company's deferred tax assets and liabilities as of December 31, 2006 and 2005 are as follows:

	2006	2005
	(In thousands)	
Current		
Deferred tax asset		
Deferred tax benefit on cash flow hedge losses	$ —	$ 14,614
Deferred tax liabilities		
Deferred tax liability on cash flow hedge gains	$ 21,378	$ —
Non-current		
Deferred tax assets		
Deferred tax benefit on deferred compensation expense	$ 2,224	$ —
Deferred tax benefit on cash flow hedge losses	—	1,677
Net operating loss carry forwards	41,220	30,176
Other	219	130
Total deferred tax assets	43,663	31,983
Deferred tax liabilities		
Property, plant, and equipment	192,921	144,628
Deferred tax liability on cash flow hedge gains	1,243	—
Deferred tax liability on convertible debenture interest	5,750	2,997
Deferred tax liability on discontinued operations	—	86
Total deferred tax liabilities	199,914	147,711
Net deferred tax liabilities	$156,251	$115,728

The provisions for income taxes for the years ended December 31, 2006, 2005 and 2004 are as follows:

	2006	2005	2004
		(In thousands)	
Current state income tax expense	$ 11	$ 51	$ 70
Current federal income tax expense	—	(23)	814
Current foreign income tax expense	262	462	301
Total current income tax expense	273	490	1,185
Deferred state income tax expense	1,600	—	—
Deferred federal income tax expense	27,501	26,312	8,756
Deferred foreign income tax expense	8,776	13,900	4,233
Total deferred income tax expense	37,877	40,212	12,989
Total	$38,150	$40,702	$14,174
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, 2006, 2005 and 2004 are as follows:

	2006	2005	2004
U.S. federal statutory tax rate	35.00%	35.00%	35.00%
Dividend income from Canadian subsidiary	—	—	1.79%
Permanent differences	.16%	.11%	.12%
State income taxes net of federal deduction	.80%	.03%	.10%
Foreign income taxes	(6.29)%	(3.36)%	(5.77)%
Other	(.74)%	.02%	(.05)%
Effective income tax rate	28.93%	31.80%	31.19%

Income tax benefits recognized as additional paid-in capital for the years ended December 31, 2005 and 2004 are as follows:

	2005	2004
	(In thousands)	
Income tax benefit recognized on employee stock option exercises	$6,536	$4,243

Included in deferred tax assets are net operating losses of approximately $117.8 million that are available for carryover beginning in the year 2006 to reduce future U.S. taxable income. The net operating losses will expire in 2007 through 2026. These net operating losses have not been reduced by a valuation allowance, because management believes that future taxable income will 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 are not included in deferred tax assets.

The Company's 2004 consolidated federal income tax return is being audited by the Internal Revenue Service. Any required adjustments will be made upon completion of the IRS audit.

13. COMMITMENTS AND CONTINGENCIES

The Company leases office buildings and other property under operating leases. Future minimum lease payments, in thousands, for operating leases with initial non-cancelable lease terms in excess of one year as of December 31, 2006, were as follows:

2007	$ 4,270
2008	3,988
2009	3,586
2010	598
Thereafter	4
Total lease commitments	$12,446

Rent expense for operating leases with terms exceeding one month was $3.5 million in 2006, $2.3 million in 2005 and $1.5 million in 2004.

As of December 31, 2006, the Company had approximately $0.6 million in letters of credit outstanding related to various state and federal bonding requirements.

In August 2001, a group of royalty owners, Athel E. Williams et al., brought suit against the Company and three of its subsidiaries in the Circuit Court of Otsego County, Michigan. The suit alleges that Terra Energy Ltd, one of Quicksilver's subsidiaries, underpaid royalties or overriding royalties to the 13 named plaintiffs and to a class of plaintiffs who have yet to be determined. The pleadings of the plaintiffs seek damages in an unspecified amount and injunctive relief against future underpayments. On January 21, 2005, the Circuit Court issued an order certifying certain claims to proceed on behalf of a class. On July 25, 2006, the Michigan Court of Appeals reversed the certification of all claims on appeal and remanded the case to the trial court for further proceedings. Based on information currently available to the Company, the Company's management believes that the final resolution of this matter will not have a material effect on its financial position, results of operations, or cash flows.

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 estimated day rates ranging from $18,500 to $22,000 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, 2006, commitments under these contracts, in thousands, were as follows:

2007	$ 51,128
2008	29,377
2009	29,627
2010	2,213
	$112,345

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 (successor in interest to Eagle Drilling, 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. The Company seeks a declaratory judgment that (i) the contracts are void and (ii) that Eagle is not entitled to early termination compensation provided for in the contracts. The Company also seeks rescission of the contracts and claim we are entitled to recover damages incurred due to Eagle's failure to perform. On October 23, 2006, Eagle Domestic Drilling sued Quicksilver in District Court of Cleveland County, Oklahoma for (i) breach of contract as to each of the three drilling contracts alleging damages of $29 million plus punitive damages and interest and (ii) tortious breach of contract alleging damages in an unspecified amount in excess of $10,000. Eagle Domestic Drilling also sought a declaratory judgment that, among other things, the contracts are valid and binding. Subsequently, on January 19, 2007, Eagle Domestic Drilling and its parent, Blast Energy Services, Inc., filed for Chapter 11 bankruptcy the United States Bankruptcy Court for the Southern District of Texas, Houston Division. At the date of this filing, the suit in Tarrant County is still pending, but is stayed. On February 21, 2007, The lawsuit in Cleveland County was dismissed. The final resolution of this matter is not expected to have a material effect on the Company's financial condition, results of operations, or cash flows.

The Company entered into firm transportations contract with pipelines during 2006. 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, 2006, commitments under these contracts, in thousands, were as follows:

2007	$ 732
2008	4,392
2009	9,506
2010	10,494
2011	10,494
Thereafter	69,422
	$105,040

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.

14. MINORITY INTEREST

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.

15. EMPLOYEE BENEFITS

Quicksilver has a 401(k) retirement plan available to all employees with three months of service and who are at least 21 years of age. Until 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 discretionary contributions by the Company to the plan. Company contributions were $1.4 million, $1.0 million and $0.3 million for the years ended December 31, 2006, 2005 and 2004, 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 $50,000 for each individual claim. The claim liability for the total group was $2.2 million, $1.8 million and $2.2 million for the plan years ended June 30, 2006, 2005 and 2004, respectively. Aggregate level reinsurance is in place for payment of claims up to $1 million over and above the estimated maximum claim liability of $2.0 million for the plan year ending June 30, 2007. Administrative expenses for each of the plan years ended June 30, 2006, 2005 and 2004 were $0.4 million.

16. 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, 2006, the Company had 77,601,922 shares of common stock outstanding.

The following table shows common share and treasury share activity since January 1, 2004:

	Common Shares Issued	Treasury Shares Held
Opening balance January 1, 2004	76,779,137	2,578,904
Stock options exercised	973,014	(10,293)
Balance at December 31, 2004	77,752,151	2,568,611
Stock options exercised	747,988	—
Restricted stock activity	149,971	2,458
Balance at December 31, 2005	78,650,110	2,571,069
Stock options exercised	1,106,095	—
Restricted stock activity	425,388	8,602
Balance at December 31, 2006	80,181,593	2,579,671

Stockholder Rights Plan

On March 11, 2003, the Company's board of directors declared a dividend distribution of one preferred share purchase right for each outstanding share of common stock of the Company outstanding on March 26, 2003. As amended through December 31, 2006, 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 $180.00.

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, 2006.

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. At December 31, 2005, 2,566,449 shares of common stock were available for issuance under the 1999 and 2004 Plans.

2006 Equity Plan

On March 17, 2006, the Board of Directors of the Company approved the Company's 2006 Equity Plan, subject to stockholder approval, and recommended that the 2006 Equity Plan be submitted to the Company's stockholders at the annual meeting of stockholders in 2006. On May 23, 2006, the Company's stockholders approved the 2006 Equity Plan. Upon approval of the 2006 Equity Plan, seven 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. Upon approval of the 2006 Equity Plan, the Company ceased to grant additional awards under the 1999 Plan and the 2004 Plan. At December 31, 2006, 6,813,863 shares of common stock were available for issuance under the 2006 Equity Plan.

Stock Options

The following table summarizes the Company's stock options activity for the three years ended December 31, 2006.

	2006		2005		2004	
	Shares	Wtd Avg Exercise Price	Shares	Wtd Avg Exercise Price	Shares	Wtd Avg Exercise Price
Outstanding at beginning of year	2,840,695	$17.13	3,653,755	$14.34	1,888,068	$ 2.97
Granted	2,401	44.39	16,100	24.90	2,766,744	17.99
Exercised	(1,106,095)	17.80	(747,988)	3.87	(983,307)	2.31
Cancelled	(47,811)	12.77	(81,172)	12.64	(17,750)	11.01
Outstanding at the end of year	1,689,190	$16.84	2,840,695	$17.13	3,653,755	$14.34
Exercisable at end of year	1,271,768	$18.51	2,190,679	$18.65	874,745	$ 3.30
Vested or expected to vest at the end of the year	1,656,776	$16.76				
Weighted average fair value of options granted		$24.99		$17.67		$ 6.62

Cash received from the exercise of stock options totaled $19.7 million, $2.9 million and $2.5 million for the years ended December 31, 2006, 2005 and 2004, respectively.

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:

	2006	2005	2004
Wtd avg grant date	Jan 3, 2006	Jan 14, 2005	Jul 6, 2004
Risk-free interest rate	4.35%	4.0%	2.7%
Expected life (in years)	10.0	7.0	4.1
Expected volatility	37.3%	38.2%	45.4%
Dividend yield	—	—	—

The following table summarizes information about stock options outstanding at December 31, 2006.

	Options Outstanding			Options Exercisable	
Range of Exercisable Prices	Shares	Wtd Avg Remaining Contractual Life	Wtd Avg Exercise Price	Shares	Wtd Avg Exercise Price
$ 0 - 6.00	26,501	0.1	$ 5.67	26,501	$ 5.67
6.01 - 12.00	642,061	2.8	10.58	247,924	9.90
12.01 - 18.00	17,307	7.4	15.83	17,307	15.83
18.01 - 24.00	998,464	2.1	21.07	975,579	21.01
24.01 - 45.00	4,857	8.6	38.68	4,457	38.17
	1,689,190	2.4	$16.84	1,271,768	$18.51

The stock options vested and exercisable at December 31, 2006 had an intrinsic value of $23.5 million and a weighted average term of 2.2 years. The stock options vested or expected to vest at December 31, 2006 had an intrinsic value of $28.1 million and a weighted average terms of 2.4 years.

Restricted Stock

The following table summarizes the Company's restricted stock and stock unit activity for the two years ended December 31, 2006.

	2006		2005	
	Shares	Wtd Avg Grant Date Fair Value	Shares	Wtd Avg Exercise Price
Outstanding at beginning of year	133,858	$33.73	—	$ —
Granted	467,215	39.10	162,217	33.64
Vested	(47,673)	33.84	(16,242)	33.23
Canceled	(41,527)	37.11	(12,117)	33.15
Outstanding at the end of year	511,873	$38.35	133,858	$33.73

The total fair value of shares vested during the years ended December 31, 2006 and 2005 was $2.1 million and $0.6 million, respectively. No restricted stock was outstanding at December 31, 2004.

17. OTHER REVENUE

Other revenue consists of the following:

	For the Years Ended December 31,		
	2006	2005	2004
		(In thousands)	
Tax credits	$ 572	$1,229	$ 221
Marketing	318	(137)	928
Ineffective cash flow hedges	23	—	—
Processing and gathering	2,909	3,152	1,407
	$3,822	$4,244	$2,556

Revenue for processing of natural gas and gathering of natural gas and NGLs represents revenue earned from third parties.

18. DISCONTINUED DRILLING OPERATIONS

On July 28, 2005, Quicksilver purchased three drilling rigs and other associated assets for $5.6 million. Thereafter, 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 $8.23 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.

19. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The following subsidiaries of Quicksilver are guarantors of Quicksilver's Senior Subordinated Notes issued March 16, 2006: Mercury Michigan, Inc., Terra Energy Ltd., GTG Pipeline Corporation, Cowtown Pipeline Funding, Inc., Cowtown Pipeline Management, Inc., Terra Pipeline Company, Beaver Creek Pipeline, LLC, 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.

Condensed Consolidating Balance Sheets

	December 31, 2006				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
	(Amounts in thousands)				
ASSETS					
Current assets	$ 165,061	$250,928	$ 78,531	$(323,556)	$ 170,964
Property and equipment, net	1,043,037	87,025	549,218	—	1,679,280
Investments in subsidiaries (equity method)	510,548	131,750	—	(634,864)	7,434
Other assets	22,397	—	2,837	—	25,234
Total assets	$1,741,043	$469,703	$630,586	$(958,420)	$1,882,912
LIABILITIES					
Current liabilities	$ 368,073	$ 91,414	$ 63,458	$(323,556)	$ 199,389
Long-term liabilities	797,304	24,577	278,545	—	1,100,426
Minority interest	—	—	7,431	—	7,431
Stockholders' equity	575,666	353,712	281,152	(634,864)	575,666
Total liabilities and stockholders' equity	$1,741,043	$469,703	$630,586	$(958,420)	$1,882,912

	December 31, 2005				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
	(Amounts in thousands)				
ASSETS					
Current assets	$ 101,587	$201,458	$ 62,105	$(251,566)	$ 113,584
Property and equipment, net	638,355	141,193	332,454	—	1,112,002
Investments in subsidiaries (equity method)	290,951	8,932	—	(291,530)	8,353
Other assets	8,000	—	1,155	—	9,155
Total assets	$1,038,893	$351,583	$395,714	$(543,096)	$1,243,094
LIABILITIES					
Current liabilities	$ 247,065	$124,780	$ 91,911	$(251,566)	$ 212,190
Long-term liabilities	408,213	24,542	214,534	—	647,289
Stockholders' equity	383,615	202,261	89,269	(291,530)	383,615
Total liabilities and stockholders' equity	$1,038,893	$351,583	$395,714	$(543,096)	$1,243,094

Condensed Consolidating Statement of Income

	Year Ended December 31, 2006				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
			(Amounts in thousands)		
Revenues	$233,757	$43,559	$116,978	$ (3,932)	$390,362
Operating expenses	148,613	18,210	53,801	(3,932)	216,692
Income from equity affiliates	17	509	—	—	526
Income from operations	85,161	25,858	63,177	—	174,196
Equity in net earnings of subsidiaries	58,543	—	—	(58,543)	—
Interest expense and other	29,766	(2)	12,563	—	42,327
Income tax provision	20,219	9,051	8,880	—	38,150
Net income	$ 93,719	$16,809	$ 41,734	$(58,543)	$ 93,719

	Year Ended December 31, 2005				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
			(Amounts in thousands)		
Revenues	$165,194	$52,678	$97,044	$ (4,468)	$310,448
Operating expenses	111,552	18,243	36,906	(4,468)	162,233
Income from equity affiliates	62	852	—	—	914
Income from operations	53,704	35,287	60,138	—	149,129
Equity in net earnings of subsidiaries	61,716	—	—	(61,716)	—
Interest expense and other	14,174	(43)	7,024	—	21,155
Income tax provision	13,974	12,366	14,362	—	40,702
Net income from continuing operations	87,272	22,964	38,752	(61,716)	87,272
Gain from discontinued operations, net	162	—	—	—	162
Net income	$ 87,434	22,964	38,752	(61,716)	$ 87,434

	Year Ended December 31, 2004				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
	(Amounts in thousands)				
Revenues	$100,126	$38,099	$42,925	$ (1,421)	$179,729
Operating expenses	87,179	13,641	20,815	(1,421)	120,214
Income from equity affiliates	75	1,103	—	—	1,178
Income from operations	13,022	25,561	22,110	—	60,693
Equity in net earnings of subsidiaries	32,539	—	—	(32,539)	—
Interest expense and other	13,600	(14)	1,661	—	15,247
Income tax provision	689	8,951	4,534	—	14,174
Net income	$ 31,272	$16,624	$15,915	$(32,539)	$ 31,272

Condensed Consolidating Statements of Cash Flows

	Year Ended December 31, 2006				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
	(Amounts in thousands)				
Cash flow provided by operations	$ 187,391	$ (37,522)	$ 70,746	$ —	$ 220,615
Cash flow used for investing activities	(504,044)	(84,675)	(252,010)	250,275	(590,454)
Cash flow provided by financing activities	307,746	126,607	177,233	(250,275)	361,311
Effect of exchange rates on cash	—	—	(509)	—	(509)
Net increase (decrease) in cash & equivalents	(8,907)	4,410	(4,540)	—	(9,037)
Cash & equivalents at beginning of period	8,990	(4,410)	9,738	—	14,318
Cash & equivalents at end of period	$ 83	$ —	$ 5,198	$ —	$ 5,281

	Year Ended December 31, 2005				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
	(Amounts in thousands)				
Cash flow provided by operations	$ 58,243	$ 40,201	$ 46,024	$—	$ 144,468
Cash flow used for investing activities	(181,614)	(45,691)	(91,964)	—	(319,269)
Cash flow provided by financing activities	121,933	—	50,493	—	172,426
Effect of exchange rates on cash	—	—	746	—	746
Net increase (decrease) in cash & equivalents	(1,438)	(5,490)	5,299	—	(1,629)
Cash & equivalents at beginning of period	10,428	1,080	4,439	—	15,947
Cash & equivalents at end of period	$ 8,990	$ (4,410)	$ 9,738	$—	$ 14,318

	Year Ended December 31, 2004				
	Quicksilver Resources Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Quicksilver Resources Inc. Consolidated
	(Amounts in thousands)				
Cash flow provided by operations	$ 48,415	$ 9,749	$ 26,683	$—	$ 84,847
Cash flow used for investing activities	(103,201)	(9,071)	(93,626)	—	(205,898)
Cash flow provided by financing activities	62,549	—	71,840	—	134,389
Effect of exchange rates on cash	—	—	(1,507)	—	(1,507)
Net increase (decrease) in cash & equivalents	7,763	678	3,390	—	11,831
Cash & equivalents at beginning of period	2,665	402	1,049	—	4,116
Cash & equivalents at end of period	$ 10,428	$ 1,080	$ 4,439	$—	$ 15,947

20. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid for interest and income taxes is as follows:

	For the Years Ended December 31,		
	2006	2005	2004
	(In thousands)		
Interest	$37,627	$21,466	$14,742
Income taxes	3	888	72

Other non-cash transactions are as follows:

	For the Years Ended December 31,		
	2006	2005	2004
	(In thousands)		
Noncash changes in working capital related to acquisition of property and equipment — net	$(48,238)	$(31,475)	$(16,651)
Tax benefit recognized on employee stock option exercises	—	6,536	4,243
Treasury stock (acquired) reissued:			
10,293 shares for non-employee director stock option exercise	—	—	189

21. RELATED PARTY TRANSACTIONS

As of December 31, 2006, 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 $1.4 million, $1.03 million and $0.86 million for rent in 2006, 2005 and 2004, respectively, for rent on buildings owned by Pennsylvania Avenue LP ("PALP"), a Mercury affiliate. 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 from PALP to Mercury. At December 31, 2006, the Company had future lease obligations to Pennsylvania of $4.6 million through 2009.

During 2006, the Company paid Regal Aviation LLC, an unrelated airplane management company, $0.2 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. In 2005 and 2004, the Company also paid $11,400 and $5,600, respectively, for the use of an airplane owned by Panther City Aviation LLC, a limited liability company owned in part by Thomas Darden.

Payments received in 2006, 2005 and 2004 from Mercury for sublease rentals, employee insurance coverage and administrative services were $0.1 million, $0.1 million and $0.1 million, respectively. In August 2006, the Company agreed to purchase furniture from PALP for $75,000. The sales price was determined using comparable rates charged by third parties.

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 3.3% 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.

22. SEGMENT INFORMATION

The Company operates in two geographic segments, the United States and Canada. Both areas are engaged in the exploration and production segment of the oil and gas industry. The Company evaluates performance based on operating income.

	United States	Canada	Corporate	Consolidated
2006				
Revenues	$ 273,636	$116,726	$ —	$ 390,362
Depletion, depreciation and accretion	48,808	29,225	767	78,800
Operating income (loss)	136,694	63,906	(26,404)	174,196
Property, plant and equipment — net	1,258,807	417,199	3,274	1,679,280
Property and equipment costs incurred	525,833	118,028	1,866	645,727
2005				
Revenues	$ 212,704	$ 97,744	$ —	$ 310,448
Depletion, depreciation and accretion	35,509	19,089	615	55,213
Operating income (loss)	106,730	61,992	(19,702)	149,129
Property, plant and equipment — net	777,330	332,580	2,092	1,112,002
Property and equipment costs incurred	241,245	118,680	1,044	360,969
2004				
Revenues	$ 136,580	$ 43,149	$ —	$ 179,729
Depletion, depreciation and accretion	30,808	9,282	601	40,691
Operating income (loss)	50,763	23,465	(13,688)	60,693
Property, plant and equipment — net	581,575	219,369	1,666	802,610
Property and equipment costs incurred	126,512	104,580	665	231,757

23. 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 with Schlumberger Data and Consulting Services and LaRoche Petroleum Consultants, Ltd., respectively. The reserve reports were prepared in accordance with guidelines established by the Securities and Exchange Commission and, accordingly, were based on existing economic and operating conditions. Natural gas 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 (See "Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves" below for a discussion of the effect of the different prices on reserve quantities and values.) 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 changes in proved reserves for the years ended December 31, 2004, 2005 and 2006 were as follows:

	Natural Gas (MMcf)			Crude Oil (MBbl)			NGL (MBbl)		
	United States	Canada	Total	United States	Canada	Total	United States	Canada	Total
December 31, 2003	643,520	146,632	790,152	13,173	—	13,173	1,918	—	1,918
Revisions	(18,350)	(12,105)	(30,455)	(43)	—	(43)	(44)	1	(43)
Extensions and discoveries	28,752	131,796	160,548	3	—	3	2,447	—	2,447
Purchases in place	5,000	3,461	8,461	—	—	—	—	—	—
Sales in place	(602)	—	(602)	(3,377)	—	(3,377)	(6)	—	(6)
Production	(30,644)	(8,707)	(39,351)	(689)	—	(689)	(128)	(1)	(129)
December 31, 2004	627,676	261,077	888,753	9,067	—	9,067	4,187	—	4,187
Revisions	(7,898)	(21,155)	(29,053)	(2,883)	—	(2,883)	(1,233)	3	(1,230)
Extensions and discoveries	128,038	79,813	207,851	280	—	280	6,884	—	6,884
Purchases in place	236	—	236	4	—	4	5	—	5
Sales in place	(65)	—	(65)	—	—	—	—	—	—
Production	(31,944)	(14,825)	(46,769)	(553)	—	(553)	(220)	(3)	(223)
December 31, 2005	716,043	304,910	1,020,953	5,915	—	5,915	9,623	—	9,623
Revisions	(80,484)	(32,938)	(113,422)	667	—	667	4,593	7	4,600
Extensions and discoveries	332,811	55,006	387,817	320	—	320	34,510	14	34,524
Purchases in place	—	—	—	—	—	—	—	—	—
Sales in place	—	(405)	(405)	—	—	—	—	—	—
Production	(35,028)	(18,238)	(53,266)	(587)	—	(587)	(741)	(5)	(746)
December 31, 2006	933,342	308,335	1,241,677	6,315	—	6,315	47,985	16	48,001
Proved developed reserves									
December 31, 2004	556,999	149,453	706,452	4,587	—	4,587	2,464	—	2,464
December 31, 2005	593,630	199,859	793,489	4,986	—	4,986	5,153	—	5,153
December 31, 2006	626,582	217,759	844,341	5,236	—	5,236	18,771	16	18,787

The capitalized costs relating to oil and gas producing activities and the related accumulated depletion, depreciation and accretion as of December 31, 2006, 2005 and 2004 were as follows:

	United States	Canada	Consolidated
		(In thousands)	
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
2004			
Proved properties	$ 644,527	$193,607	$ 838,134
Unevaluated properties	57,929	39,239	97,168
Accumulated DD&A	(180,975)	(14,440)	(195,415)
Net capitalized costs	$ 521,481	$218,406	$ 739,887

Costs incurred in oil and gas property acquisition, exploration and development activities during the years ended December 31, 2006, 2005 and 2004 were as follows:

	United States	Canada (In thousands)	Consolidated
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
2004			
Proved acreage	$ 11,907	$ 2,942	$ 14,849
Unproved acreage	31,857	7,144	39,001
Development costs	45,213	71,094	116,307
Exploration costs	25,673	22,631	48,304
Total	$114,650	$103,811	$218,461

Results of operations from producing activities for the years ended December 31, 2006, 2005 and 2004 are set forth below:

	United States	Canada	Consolidated
		(In thousands)	
2006			
Natural gas, crude oil & NGL sales	$270,535	$116,015	$386,540
Oil & gas production expense	87,199	23,596	110,795
Depletion 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, crude oil & NGL sales	$209,715	$ 96,489	$306,204
Oil & gas production expense	69,609	16,663	86,272
Depletion 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
2004			
Natural gas, crude oil & NGL sales	$134,268	$ 42,905	$177,173
Oil & gas production expense	55,224	10,402	65,626
Depletion expense	26,444	8,980	35,424
	52,600	23,523	76,123
Income tax expense	18,410	7,908	26,318
Results from producing activities	$ 34,190	$ 15,615	$ 49,805

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,		
	2006	2005	2004
Natural gas — Henry Hub-Spot	$ 5.64	$10.08	$ 6.18
Natural gas — AECO	5.39	8.41	5.18
Crude oil — WTI Cushing	60.85	61.06	43.36

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, 2006, 2005 and 2004 were as follows:

	United States	Canada	Consolidated
		(In thousands)	
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 net cash flows relating to proved reserves	$ 1,125,490	$ 360,335	$ 1,485,825
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 net cash flows relating to proved reserves	$ 1,230,978	$ 593,154	$ 1,824,132
2004			
Future revenues	$ 4,241,385	$1,306,819	$ 5,548,204
Future production costs	(1,456,005)	(295,443)	(1,751,448)
Future development costs	(116,559)	(145,297)	(261,856)
Future income taxes	(836,557)	(238,141)	(1,074,698)
Future net cash flows	1,832,264	627,938	2,460,202
10% discount — calculated difference	(1,133,990)	(355,481)	(1,489,471)
Standardized measure of discounted future net cash flows relating to proved reserves	$ 698,274	$ 272,457	$ 970,731

The primary changes in the standardized measure of discounted future net cash flows for the years ended December 31, 2006, 2005 and 2004 were as follows:

	As of December 31,		
	2006	2005	2004
		(In thousands)	
Net changes in price and production costs	$(1,332,216)	$ 734,930	$ (82,974)
Development costs incurred	78,063	44,399	61,069
Revision of estimates	(94,080)	(29,506)	(30,509)
Changes in estimated future development costs	42,015	43,939	3,183
Purchase and sale of reserves, net	(1,977)	824	(23,367)
Extensions and discoveries	661,033	515,810	219,656
Net change in income taxes	302,342	(405,724)	(21,638)
Sales of oil and gas net of production costs	(275,745)	(219,932)	(111,987)
Accretion of discount	260,340	134,428	120,065
Other	21,918	34,233	(11,508)
Net increase (decrease)	$ (338,307)	$ 853,401	$ 121,990

24. SELECTED QUARTERLY DATA (UNAUDITED)

	Mar 31	Jun 30	Sep 30	Dec 31
	(In thousands, except per share data)			
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 income per share	$ 0.36	$ 0.31	$ 0.30	$ 0.26
Diluted net income per share	0.34	0.29	0.28	0.24
2005				
Operating revenues	$55,249	$68,540	$83,773	$102,886
Operating income	19,943	30,026	41,228	57,932
Net income from continuing operations	10,754	17,185	24,693	34,640
Net income	10,754	17,185	24,755	34,740
Basic net income per share from continuing operations	$ 0.14	$ 0.23	$ 0.33	$ 0.46
Basic net income per share	0.14	0.23	0.33	0.46
Diluted net income per share from continuing operations	0.14	0.21	0.31	0.43
Diluted net income per share	0.14	0.21	0.31	0.43

25. QUICKSILVER GAS SERVICES LP

On February 11, 2007 the Company's wholly-owned subsidiary, Quicksilver Gas Services LP ("QGSLP"), filed a registration statement on Form S-1 with the Securities and Exchange Commission to become a publicly traded partnership through a proposed underwritten initial public offering. The registration statement contemplates the offering of 3,375,000 common units representing approximately 19% of the limited partner interests in QGSLP, with anticipated aggregate gross proceeds of approximately $67.5 million. Upon completion of the offering, the Company expects to retain common units and subordinated units representing an approximate 75% limited partner interest, and the entire 2% general partner interest in the publicly traded partnership.

QGSLP will engage in the business of gathering and processing natural gas produced from the Barnett Shale formation in the Fort Worth Basin of northern Texas. QGSLP will own a pipeline system and a natural gas processing plant in the southern portion of the Fort Worth Basin.

ITEM 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

ITEM 9A. *Controls and Procedures*

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Exchange Act Rule 13a-15. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective to provide reasonable assurance that material information required to be disclosed by us (including our consolidated subsidiaries) in reports that we file or submit under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported on a timely basis.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in the Exchange Act Rule 13a-15(f). Our management conducted an assessment of our internal control over financial reporting based on the framework established by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control — Integrated Framework.* Based on this assessment, our management has concluded that, as of December 31, 2006, our internal control over financial reporting is effective. Our independent registered public accounting firm, Deloitte & Touche LLP, have issued an attestation report on management's assessment of our internal control over financial reporting, 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, 2006 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Quicksilver Resources Inc.

Fort Worth, Texas

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Quicksilver Resources Inc. and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, 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. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, 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, 2006 of the Company and our report dated February 28, 2007 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 28, 2007

ITEM 9B. *Other Information*

None.

PART III

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

The information concerning our directors set forth under "Corporate Governance Matters — the Board of Directors" and "Corporate Governance Matters — Family Relationship Between Directors" in the proxy statement for our May 23, 2007 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 set forth under "Corporate Governance Matters — Committees of the Board" in the proxy statement for our May 23, 2007 annual meeting of stockholders is incorporated herein by reference. Certain information concerning our executive officers is set forth under the heading "Business — Executive Officers" 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 23, 2007 annual meeting of stockholders is incorporated herein by reference.

The information concerning our audit committee set forth under "Corporate Governance Matters — Committees of the Board" in the proxy statement for our May 23, 2007 annual meeting of stockholders is incorporated herein by reference.

The information regarding our Code of Ethics set forth under "Corporate Governance Matters — Corporate Governance Principles, Processes and Code of Business Conduct and Ethics" in the proxy statement for our May 23, 2007 annual meeting of stockholders is incorporated herein by reference.

ITEM 11. *Executive Compensation*

The information set forth under "Corporate Governance Matters — Compensation of Directors," "Executive Compensation," "Compensation Discussion and Analysis," and "Compensation Committee Report" in our proxy statement for our May 23, 2007 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 23, 2007 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 23, 2007 annual meeting of stockholders is incorporated herein by reference.

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

The information set forth under "Transactions with Management and Certain Stockholders," and "Corporate Governance Matters — Independent Directors" in the proxy statement for our May 23, 2007 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 23, 2007 annual meeting of stockholders is incorporated herein by reference.

PART IV

ITEM 15. ***Exhibits and Financial Statement Schedules***

We will furnish you, without charge, a copy of any exhibit to this Annual Report on Form 10-K upon written request. Written requests to obtain an exhibit should be sent to the Investor Relations Department at 777 West Rosedale Street, Suite 300, Fort Worth, Texas 76104.

The following documents are filed as part of this report:

1. Financial Statements:

The following financial statements of ours and the report of our Independent Auditors thereon are included on pages 53 through 98 of this Form 10-K.

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets as of December 31, 2006 and 2005

Consolidated Statements of Income and Comprehensive Income for the Years Ended December 31, 2006, 2005 and 2004

Consolidated Statements of Stockholders' Equity for the years ended December 31, 2006, 2005 and 2004

Consolidated Statements of Cash Flows for the Years Ended December 31, 2006, 2005 and 2004

Notes to Consolidated Financial Statements for the Years Ended December 31, 2006, 2005 and 2004

2. Financial Statement Schedules:

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

3. Exhibits:

Exhibit No.	Sequential Description
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	Bylaws of Quicksilver Resources Inc. (filed as Exhibit 4.2 to the Company's Form S-4, File No. 333-66709, filed November 3, 1998 and included herein by reference).
3.4	Amendment to the Bylaws of Quicksilver Resources Inc., adopted November 30, 1999 (filed as Exhibit 3.4 to the Company's Form 10-K filed March 27, 2001 and included herein by reference).
3.5	Amendment to the Bylaws of Quicksilver Resources Inc., adopted June 5, 2001 (filed as Exhibit 3.2 to the Company's Form 10-Q filed August 14, 2001 and included herein by reference).
3.6	Amendment to the Bylaws of Quicksilver Resources Inc., adopted March 11, 2003 (filed as Exhibit 3.8 to the Company's Form 10-K filed March 26, 2003 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).

Exhibit No.	Sequential Description
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 Registration Statement on 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 10.2 to the Company's Form 8-K filed April 19, 2005 and included herein by reference).
+ 10.4	Form of Incentive Stock Option Agreement pursuant to the Quicksilver Resources Inc. Amended and Restated 1999 Stock Option and Retention Stock Plan (filed as Exhibit 10.2 to the Company's Form 8-K filed January 28, 2005 and included herein by reference).
+ 10.5	Form of Non-Qualified Stock Option Agreement pursuant to the Quicksilver Resources Inc. Amended and Restated 1999 Stock Option and Retention Stock Plan (filed as Exhibit 10.3 to the Company's Form 8-K filed January 28, 2005 and included herein by reference).
+ 10.6	Form of Retention Share Agreement pursuant to the Quicksilver Resources Inc. Amended and Restated 1999 Stock Option and Retention Stock Plan (filed as Exhibit 10.3 to the Company's Form 8-K filed April 19, 2005 and included herein by reference).
+ 10.7	Form of Restricted Stock Unit Agreement pursuant to the Quicksilver Resources Inc. Amended and Restated 1999 Stock Option and Retention Stock Plan (filed as Exhibit 10.4 to the Company's Form 8-K filed April 19, 2005 and included herein by reference).
+ 10.8	Quicksilver Resources Inc. Amended and Restated 2004 Non-Employee Director Equity Plan (filed as Exhibit 10.1 to the Company's Form 8-K filed February 22, 2006 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	Description of Non-Employee Director Compensation for Quicksilver Resources Inc.
+ 10.12	Quicksilver Resources Inc. 2006 Executive Bonus Program (filed as Exhibit 10.1 to the Company's Form 8-K filed April 5, 2006 and included herein by reference).
+10.13	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).
+ 10.14	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).
+10.15	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).
+10.16	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).

Exhibit No.	Sequential Description
+ 10.17	Quicksilver Resources Inc. 2006 Equity Plan (filed as Appendix C to Quicksilver Resources Inc. Proxy Statement filed April 7, 2006 and included herein by reference).
+ 10.18	Form of Restricted Share Agreement pursuant to the 2006 Equity Plan (filed as Exhibit 10.2 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.19	Form of Restricted Stock Unit Agreement pursuant to the 2006 Equity Plan (filed as Exhibit 10.3 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.20	Form of Quicksilver Resources Canada Inc. Restricted Stock Unit Agreement pursuant to the 2006 Equity Plan (filed as Exhibit 10.4 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.21	Form of Incentive Stock Option Agreement pursuant to the 2006 Equity Plan (filed as Exhibit 10.5 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.22	Form of Non-Qualified Stock Option Agreement pursuant to the 2006 Equity Plan (filed as Exhibit 10.6 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.23	Form of Non-Employee Director Restricted Share Agreement pursuant to the 2006 Equity Plan (filed as Exhibit 10.7 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
+ 10.24	Form of Non-Employee Director Non-Qualified Stock Option Agreement pursuant to the 2006 Equity Plan (filed as Exhibit 10.8 to the Company's Form 8-K filed May 25, 2006 and included herein by reference).
10.25	Credit Agreement, dated as of July 28, 2004, among Quicksilver Resources Inc., as Borrower, Bank One, NA, Global Administrative Agent, and the other agents and financial institutions listed therein (filed as Exhibit 10.1 to the Company's Form 10-Q filed August 6, 2004 and included herein by reference).
10.26	Credit Agreement, dated as of July 28, 2004, among MGV Energy, Inc., as Borrower, Bank One, NA, Canada Branch, Canadian Administrative Agent, Bank One, NA, Global Administrative Agent, and the financial institutions listed therein (filed as Exhibit 10.2 to the Company's Form 10-Q filed August 6, 2004 and included herein by reference).
10.27	First Amendment to Combined Credit Agreements, dated as of September 24, 2004, among Quicksilver Resources Inc., MGV Energy and the agents and combined lenders identified therein (filed as Exhibit 10.2 to the Company's Form 8-K filed October 12, 2004 and included herein by reference).
10.28	Second Amendment to Combined Credit Agreements, dated as of January 11, 2005, among Quicksilver Resources Inc., MGV Energy Inc. and the agents and combined lenders identified therein (filed as Exhibit 10.17 to the Company's Form 10-K filed March 16, 2005 and included herein by reference).
10.29	Third Amendment to Combined Credit Agreements, dated as of June 17, 2005, among Quicksilver Resources Inc., MGV Energy Inc. and the agents and combined lenders identified therein (filed as Exhibit 10.1 to the Company's Form 8-K filed June 28, 2005 and included herein by reference).
10.30	Fourth Amendment to Combined Credit Agreements, dated as of November 30, 2005, among Quicksilver Resources Inc., MGV Energy Inc. and the agents and combined lenders identified therein (filed as Exhibit 10.2 to the Company's Form 8-K, filed December 1, 2005 and included herein by reference).
10.31	Fifth Amendment to Combined Credit Agreement, dated as of January 13, 2006, among Quicksilver Resources Inc., MGV Energy Inc. and the agents and combined lenders identified therein (filed as Exhibit 10.1 to the Company's Form 8-K filed January 19, 2006 and included herein by reference).
10.32	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).
10.33	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 on Exhibit 10.2 to the Company's Form 8-K, filed February 12, 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.

Exhibit No.	Sequential Description
* 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: March 1, 2007

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	March 1, 2007
/s/ Glenn Darden Glenn Darden	President and Chief Executive Officer (Principal Executive Officer); Director	March 1, 2007
/s/ Philip Cook Philip Cook	Senior Vice President — Chief Financial Officer (Principal Financial Officer)	March 1, 2007
/s/ D. Wayne Blair D. Wayne Blair	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)	March 1, 2007
/s/ Anne Darden Self Anne Darden Self	Director	March 1, 2007
/s/ James Hughes James Hughes	Director	March 1, 2007
/s/ Steven M. Morris Steven M. Morris	Director	March 1, 2007
/s/ W. Yandell Rogers, III W. Yandell Rogers, III	Director	March 1, 2007
/s/ Mark J. Warner Mark J. Warner	Director	March 1, 2007

DIRECTORS

Thomas F. Darden
Chairman

Glenn Darden

James A. Hughes*

Steven M. Morris*

W. Yandell Rogers III*

Anne D. Self

Mark 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

William S. Buckler III
Vice President – U.S. Operations

Robert N. Wagner
Vice President – Reservoir Engineering

D. Wayne Blair
Vice President & Controller

Anne D. Self
Vice President – Human Resources

MarLu Hiller
Vice President – Treasurer

Richard C. Buterbaugh
Vice President – Investor Relations & Corporate Planning

* Member of the Audit, Compensation, and Nominating and Corporate Governance Committees

HEADQUARTERS

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Fort Worth, Texas 76104
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Fax: 817-665-5004
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Calgary, Alberta Canada
T2G OP8
Phone: 403-537-2455
Fax: 403-262-6115

Dana W. Johnson
Senior Vice President & Chief Operating Officer

REGISTRAR AND TRANSFER AGENT

Mellon Investor Services
Stock Transfer Department
480 Washington Blvd.
Jersey City, New Jersey 07310
866-637-5420
www.melloninvestor.com

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 23, 2007 at the Petroleum Club, 777 Main St., Fort Worth, Texas.

Photography: Kevin Brown of KB Digital Shots

QUICKSILVER

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