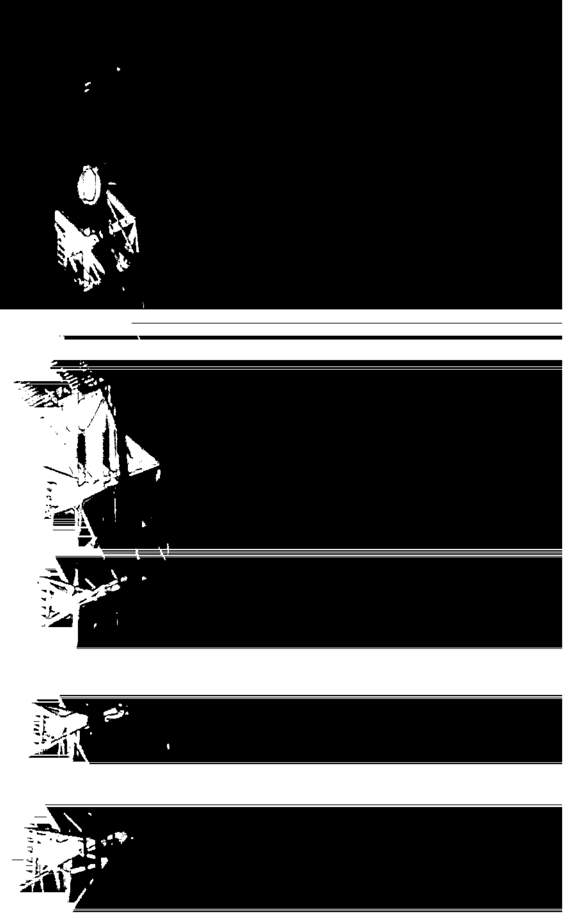
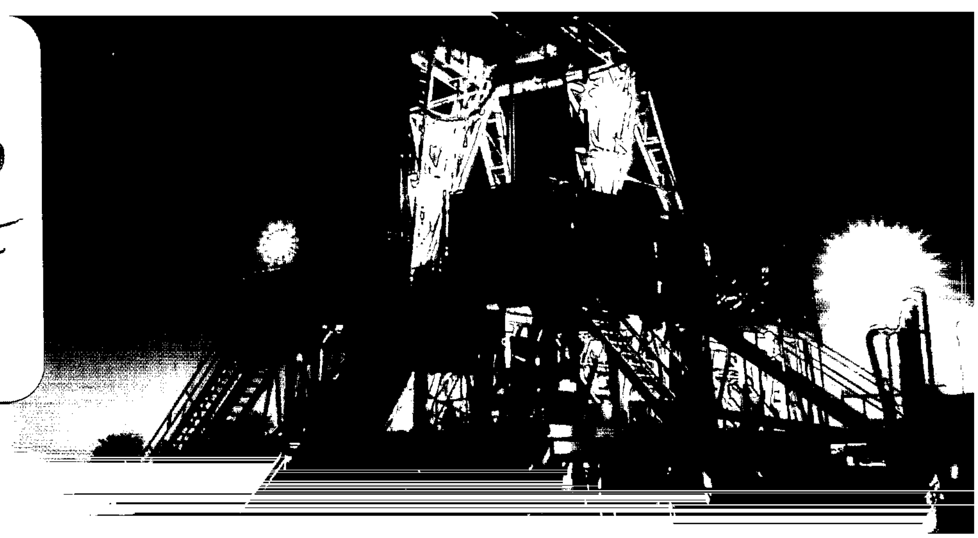
UNCONVENTIONAL STRATEGY+TALENT+TECHNOLOGY= UNCONVENTIONAL SUCCESS





QUICKSILVER RESOURCES INC. 2004 ANNUAL REPORT

CORPORATE PROFILE *Quicksilver Resources Inc. is a natural gas and crude oil exploration and production company engaged in the development and acquisition of long-lived producing natural gas and crude oil properties. The company, based in Fort Worth, Texas, is widely recognized as a leader in the development and production of unconventional natural gas reserves, including coal bed methane, shale gas, and tight sands gas. The company's reserves are located in Michigan, Indiana/Kentucky, northern Rockies, north central Texas, and in the Canadian province of Alberta.*

As of December 31, 2004, the company had estimated proved reserves of 968 billion cubic feet of gas equivalent (Bcfe), of which 94% were natural gas and natural gas liquids, and 77% were proved developed. As of year-end 2004, the company operated 70% of its reserves. The company currently has U.S. offices located in Gaylord, Michigan; Corydon, Indiana; Cut Bank, Montana; Granbury, Texas and Fort Worth, Texas. Quicksilver also has a Canadian subsidiary, MGV Energy Inc. located in Calgary, Alberta. Its common shares are traded on the New York Stock Exchange under the ticker symbol "KWK."

FINANCIAL HIGHLIGHTS

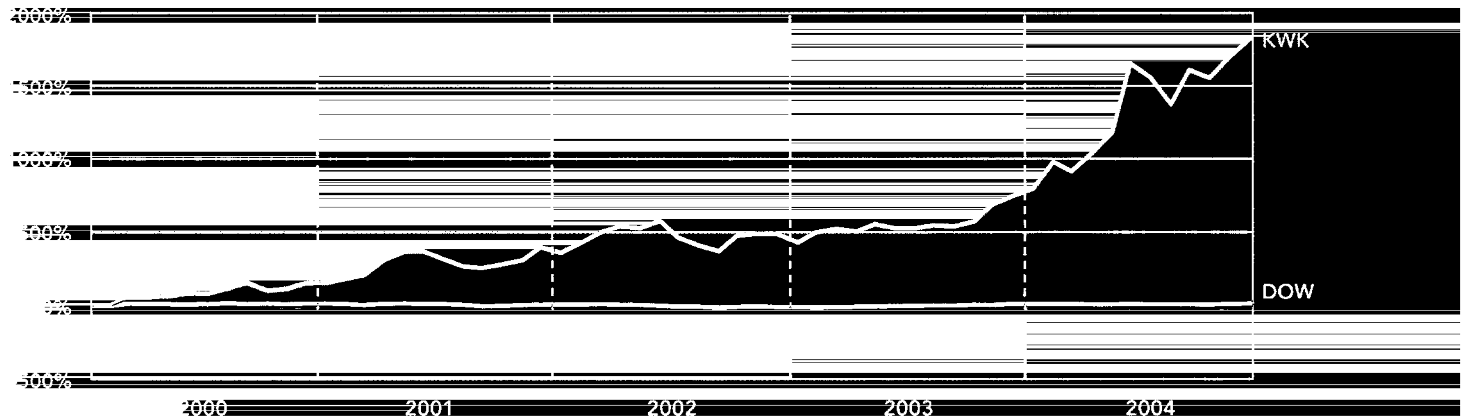
(In thousands, except per share, production and product price data)

	2004	2003 (a)	2002 (a)	2001 (a)	2000 (a)
REVENUES	**$ 179,729**	$ 140,949	$ 121,979	$ 141,963	$ 118,392
INCOME BEFORE INCOME TAXES	**$ 45,446**	$ 28,502	$ 21,333	$ 30,110	$ 27,731
NET INCOME	**$ 31,272**	$ 16,208	$ 13,835	$ 19,310	$ 17,618
NET INCOME PER DILUTED SHARE	**$ 0.62**	$ 0.35	$ 0.34	$ 0.50	$ 0.48
DILUTED WEIGHTED AVG. NUMBER OF SHARES OUTSTANDING FOR THE PERIODS	**51,343**	45,689	40,789	38,442	36,934
TOTAL ASSETS	**$ 888,334**	$ 666,934	$ 529,538	$ 471,884	$ 440,111
LONG-TERM DEBT	**$ 399,134**	$ 249,097	$ 248,493	$ 248,425	$ 239,986
TOTAL STOCKHOLDERS' EQUITY	**$ 304,276**	$ 241,816	$ 128,905	$ 94,387	$ 86,758
NATURAL GAS & NGL PRODUCTION (MMCFE)	**40,124**	35,345	33,781	33,859	27,621
AVG. NATURAL GAS & NGL PRICE PER MCFE (b)	**$ 3.85**	$ 3.38	$ 2.74	$ 3.04	$ 3.08
CRUDE OIL PRODUCTION (MBBL)	**689**	808	905	1,059	1,035
AVERAGE PRICE PER BBL (b)	**$ 33.07**	$ 24.23	$ 21.74	$ 21.03	$ 22.87

(a) Share and per share amounts have been adjusted to reflect a two-for-one stock split effected in the form of a stock dividend in June 2004.
(b) Average prices reflect the effects of hedging transactions.

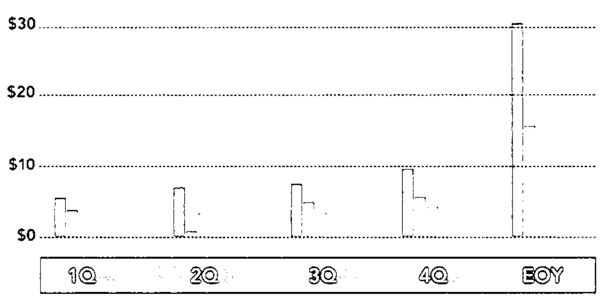
COVER: PATTERSON #18 RIG IN BARNETT SHALE BY KEVIN BROWN OF KB DIGITAL SHOTS

KWK STOCK INFORMATION

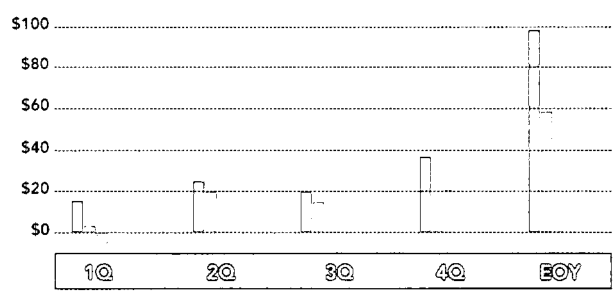


RESERVES AND HISTORICAL DATA

QUICKSILVER RESOURCES INC.
NET INCOME ($MM)

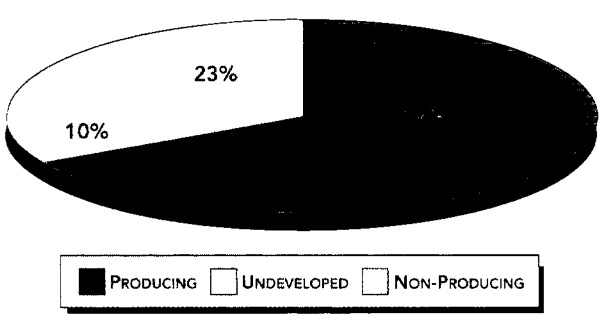


QUICKSILVER RESOURCES INC.
OPERATING CASH FLOW ($MM)

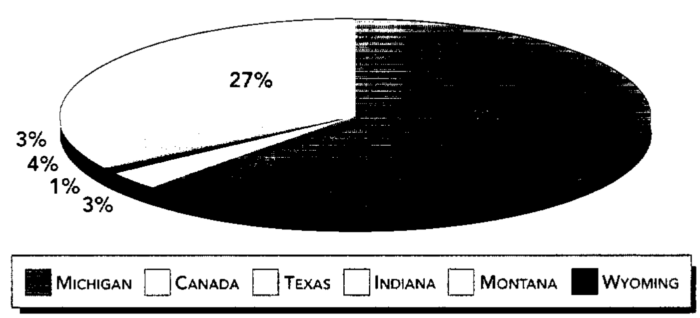


2004 2003 2002 2001 2000

RESERVES BY CATEGORY



RESERVES BY LOCATION



LETTER TO OUR SHAREHOLDERS:

ONE OF THE MOST FASCINATING ASPECTS OF OUR INDUSTRY is the progress of technology. This can be said for many industries, but in this particular business, which is devoted to extracting natural gas and oil from the ground, the advancements over the last several years have been remarkable.

THE BUSINESS MODEL FOR QUICKSILVER RESOURCES is dedicated to the search for and production of natural gas from subsurface rock formations that historically have been considered the source rocks creating the hydrocarbons, not the reservoir rocks that actually produce them. Advancements in identifying, drilling, and stimulation of these tight formations are proving these rocks can be both productive and highly profitable.

QUICKSILVER IS A LEADER IN DISCOVERING AND DEVELOPING these new unconventional gas resources. After applying new completion and production techniques to a shallow fractured shale in northern Michigan, the company greatly expanded the size of the original development, and today the Antrim Shale area contains several trillion cubic feet of recoverable gas for our country's energy needs. Quicksilver then expanded into Alberta, and after two years of testing a large area, became the first producer of commercial coal bed methane in Canada. What is remarkable about this achievement is that the shallow coal beds now producing large amounts of natural gas were drilled through for years by producers looking for deeper conventional production targets. Today, the National Energy Board of Canada estimates that coal bed methane will comprise over ten percent of all Canadian gas production by 2015.

EIGHT YEARS AGO, PRIOR TO GOING PUBLIC, we drilled a well southwest of Fort Worth in an attempt to extend the productive fairway of the prolific Barnett Shale trend. The well produced natural gas but was a marginal producer due to inefficient completion methods existing at the time. The company continued to monitor the Barnett activity and two years ago jumped back into the play as companies began to utilize horizontal drilling and improved stimulation techniques.

EARLY RECOGNITION OF THE POTENTIAL WAS CRITICAL and the Quicksilver team moved quickly. Today, the Canadian and Texas projects give the company over 4,000 drilling locations and at least two trillion cubic feet of gas potential to develop in the coming years. The company currently has drilling rights on 1,600,000 net acres in North America. Quicksilver is producing unconventional gas in four different geologic basins and is one of the few companies in the industry not reliant on the acquisition of existing producing properties to achieve double digit growth rates.

THE BUSINESS MODEL IS WORKING due to the dedication, drive, and talent of our people. As the company has grown, we have been fortunate to attract new highly skilled individuals that have added to the efficiency of the Quicksilver team. This efficiency is being recognized on Wall Street and is translating into increased value for our shareholders.

2005 WILL BE THE MOST ACTIVE YEAR YET FOR QUICKSILVER. The company is in solid financial shape and with the expiration of low-priced gas hedges at the end of April, and increasing production from the new projects, we are poised to deliver very strong results.

WE WOULD LIKE TO THANK MEMBERS OF OUR BOARD OF DIRECTORS for all of their efforts on behalf of the company. In these days of magnified scrutiny on all public companies, the acumen and guidance of the board is a true strength of the company. We would also like to thank our shareholders for their belief in and support of Quicksilver's strategy.

WITH AN IMPROVING ECONOMY and a growing demand for natural gas, we look forward to building our volumes by capitalizing on our favorable land positions and pursuing new unconventional targets.

Very truly yours,

Thomas F. ("Toby") Darden
Chairman of the Board

Glenn Darden
President & Chief Executive Officer

STRATEGY. TALENT. TECHNOLOGY.

A Large Inventory of Drilling Locations

Early in the evolution of Quicksilver, the company realized that to be profitable in unconventional natural gas, it must have a well defined strategy. In order to sustain growth, the company needed to utilize technology to improve recoveries from these tight formations. Quicksilver management believed that these types of reservoirs were the future of onshore North American gas production and that Quicksilver could be a leader in this development play. Today, the company has over 4,000 unconventional natural gas drilling locations in four proven hydrocarbon basins in North America. These are, in order of maturity, the Antrim Shale in Michigan, the New Albany Shale in Indiana and Kentucky, the Horseshoe Canyon coal beds (CBM) in Alberta, Canada, and the Barnett Shale in north central Texas.

Each Success Funds the Next

As indicated above, the Antrim Shale and our other properties in Michigan have provided the company with a solid revenue base since its inception. The Antrim Shale is a long-life reservoir with at least another 20 years of productive life. As such, Antrim Shale revenues have supported the pursuit of coal bed methane in Alberta, Canada, which the company has been aggressively drilling for the past three years. As the company continues the development of its Canadian asset, that revenue stream will, in turn, fund the further exploration and development of the Barnett Shale play, which is currently in its early stages.

Talent, Teamwork and Technology

It is not enough to simply have a strategy. Execution is the key. Talent and teamwork are required to identify new plays very early in the game to allow the company to lease acreage. Quicksilver Resources' team and its subsidiary, MGV Energy Inc., believed in the Canadian CBM project in its very early stages. The same is true for the Barnett Shale play in Texas, and as a result, the company has been very successful in securing large acreage positions in each area.

Unconventional natural gas, by definition, is found in very tight rock. In most unconventional reservoirs, operators expect to recover small percentages of the total gas in place (*i.e., contained within the rock*). It takes the application of appropriate technology to reap commercial volumes of gas. In some cases it takes three dimensional (3-D) seismic to identify possible drilling locations. It takes innovative fracture stimulation techniques. It takes skill and teamwork. It requires a sharing of knowledge within the team. Drilling techniques and completion technology are shared from basin to basin — applying the lessons learned in Antrim Shale to New Albany Shale, to coals in Canada, to Barnett Shale.

A Net Asset Value Company

Quicksilver is a net asset value company. Its assets are the natural gas reserves we discover. For the most part these reserves are long-lived and each project usually covers a large geographic area. For these reasons the company takes a long-term approach by building and owning the necessary gathering, pipeline, and facility infrastructure. This approach allows the company to control more of the process and captures more of the value chain for our shareholders.

Opportunity Times Four

Quicksilver's four productive hydrocarbon basins are all unconventional natural gas plays at different stages of maturity, development and production — running the gamut from high growth potential to long-term sustained production with established infrastructure and facilities.

Highly Prospective – Texas Barnett Shale

The company's Barnett Shale project is currently comprised of more than 200,000 net acres over an area from western Johnson County, eastern Hood County, eastern Somervell County, northern Bosque County to western Hill County. The Barnett Shale project is the company's newest, highly prospective unconventional gas play and is located in what is currently the largest producing natural gas field in Texas.

ESTIMATED TEXAS RESERVES AS OF 12/31/04	
Proved Developed Producing (PDP)	2.6 Bcfe
Proved Developed Nonproducing (PDNP)	16.7 Bcfe
Proved Undeveloped (PUD)	17.4 Bcfe
Total for Texas	36.7 Bcfe

The formation is approximately 350 feet thick, located at between 6,300 and 6,800 feet in depth. In the northern portion of the Barnett Shale play, a limestone formation located at the base of the shale acts as a natural stimulation barrier for conventional vertical wells. This limestone formation does not exist in the southern portion of the play in which the company's acreage position is located. Accordingly, Quicksilver is using horizontal drilling and multiple stage stimulations to access more fractured shale and avoid an underlying water zone (Ellenberger formation). The company is finding that this new technology is now yielding successful wells, enhancing production volumes and greatly expanding the play.

In addition to an active and aggressive five– to seven– year drilling program that includes as many as 1,000 drilling locations, the company is investing in the necessary infrastructure to gather and transport the field's output. In the first quarter of 2005, Quicksilver Resources began construction on the Cowtown Pipeline, Phase One, which will include close to 22 miles of 8-inch pipe running from the northwest corner of Johnson County to southern Hood County to gather both Quicksilver and third-party volumes. The company is also building a natural gas liquids extraction facility with a total capacity of 75 MMcf/d, which is expected to be operational in the fourth quarter of 2005.

During 2005, the company plans to drill a minimum of 40 net Barnett Shale wells in north Texas with a capital expenditure budget of approximately $105 million assuming two drilling rigs in operation. The budget includes seismic, land and necessary facility and pipeline infrastructure costs. This budget may be increased with the addition of a third drilling rig by mid-year depending on the success of the play.

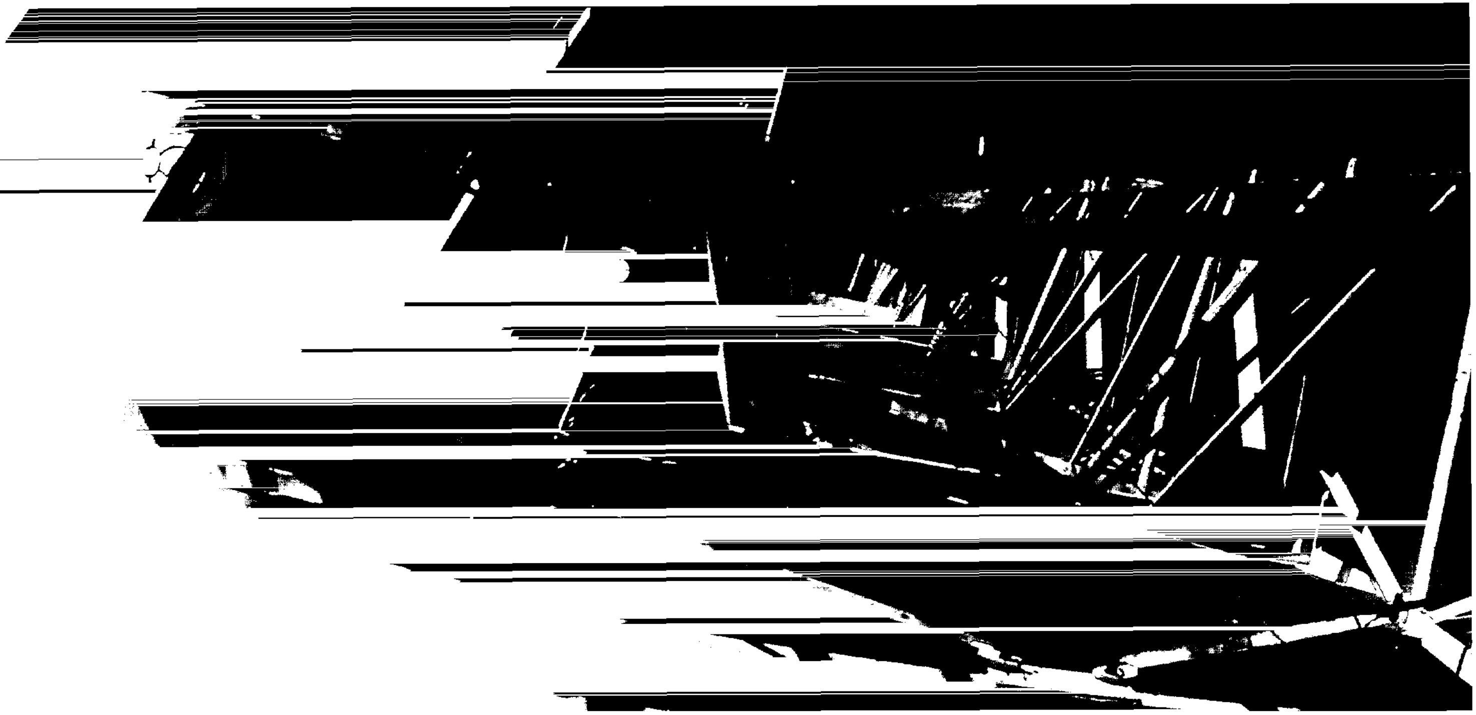
The company has seen steady improvements in completions and well performance, and firmly believes the Barnett Shale will give the company an excellent return on its drilling dollars and will become its best producing area.

Ramping up Production

Alberta coal bed methane (CBM) is one of the cleanest burning fuels in existence today, and the Horseshoe Canyon CBM from this province can be tied in directly to a pipeline without dewatering or other processing. With a land position of more than 500,000 net acres in Alberta, approximately 400,000 acres in the Horseshoe Canyon trend and another 180,000 acres in the deeper Mannville trend (Note – These trends are overlapping.), the company has a prospective drilling inventory in the area of nearly 3,000 locations. Through its Canadian subsidiary MGV Energy Inc., Quicksilver had drilled more than 1,300 gross and approximately 600 net wells, as of the end of February 2005 — 329 net wells in 2004.

ESTIMATED CANADIAN RESERVES AS OF 12/31/04	
Proved Developed Producing (PDP)	127.3 Bcfe
Proved Developed Nonproducing (PDNP)	22.2 Bcfe
Proved Undeveloped (PUD)	111.6 Bcfe
Total for Canada	261.1 Bcfe

After the acquisition of additional acreage and net proved reserve additions equal to roughly 5 Bcf in early first quarter of 2004, Quicksilver embarked on an extensive drilling program including exploratory, pilot and development wells during the remainder of the year. The



HOUSANDS OF FUTURE DRILLING LOCATIONS FOUR PROVEN NATURAL

target horizons continue to be chiefly the Horseshoe Canyon coals and the deeper Mannville coals. In addition, the company's Wood River acreage is located in the middle of one of Alberta's oldest and largest oil and gas fields and features other multi-zone targets.

As of February 2005, daily production from the company's Canadian CBM operations was more than 40 MMcf/d, already an increase of 38% from the 29 MMcf/d reported at the beginning of the fourth quarter of 2004. Overall, the CBM wells are performing as expected with the higher flow rates coming from wells north of the Palliser Block. On a per well basis across the producing fairway, average production rates range from 75 Mcf/d to 200 Mcf/d.

Quicksilver is using multiple drilling rigs, and is constructing additional production facilities and infrastructure to accommodate the new developments. The company is targeting to exceed 55 MMcf/d of CBM production by year-end 2005. Toward that end, the company is investing approximately $100 million in its drilling and development plan for the year, which includes about 490 wells (approximately 275 net wells) and the necessary compression facilities and infrastructure. Joint venture projects with split working interests account for approximately 43% of Quicksilver's 2005 capital expenditure budget for Canada.

Sustaining Growth – Michigan Antrim Shale

Quicksilver has grown production in the Antrim Shale formation for more than 13 years. As the company's most mature development project, this basin is a long life gas reservoir in relatively slow decline and is the foundation of the company's reserves, accounting for more than 62% of its current production base. Yet there remains plenty of opportunity to boost production rates through stimulation and re-completions. Quicksilver believes that the Michigan Antrim Shale formation offers the company many years of solid production.

ESTIMATED MICHIGAN RESERVES AS OF 12/31/04	
Proved Developed Producing (PDP)	487.6 Bcfe
Proved Developed Nonproducing (PDNP)	53.9 Bcfe
Proved Undeveloped (PUD)	59.8 Bcfe
Total for Michigan	601.3 Bcfe

The team's knowledge of this productive formation is thorough. In the past seven years, the company has drilled more than 900 wells with per well reserves of 400 MMcf to

800 MMcf. Typically, Michigan Antrim Shale wells reach a production level of 125 Mcf/d to 200 Mcf/d in six to twelve months, continue to produce at that level for one to two years, and then decline by eight to ten percent per year over a long productive life.

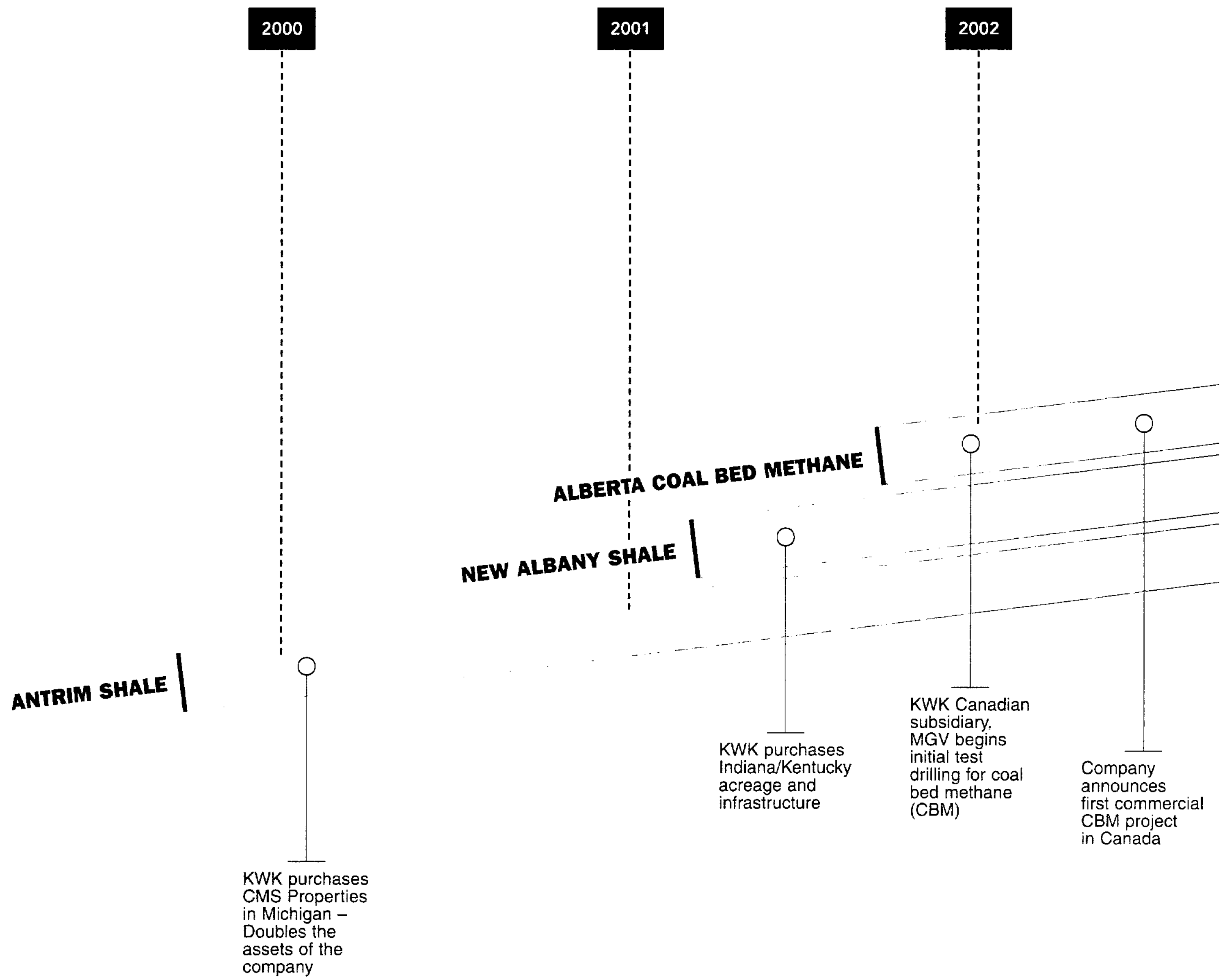
In 2004, the company completed 44 net wells. In 2005, the drilling plan is designed to help further define the producing fairway and test new technology in this maturing play.

Future Development – Indiana/Kentucky New Albany Shale

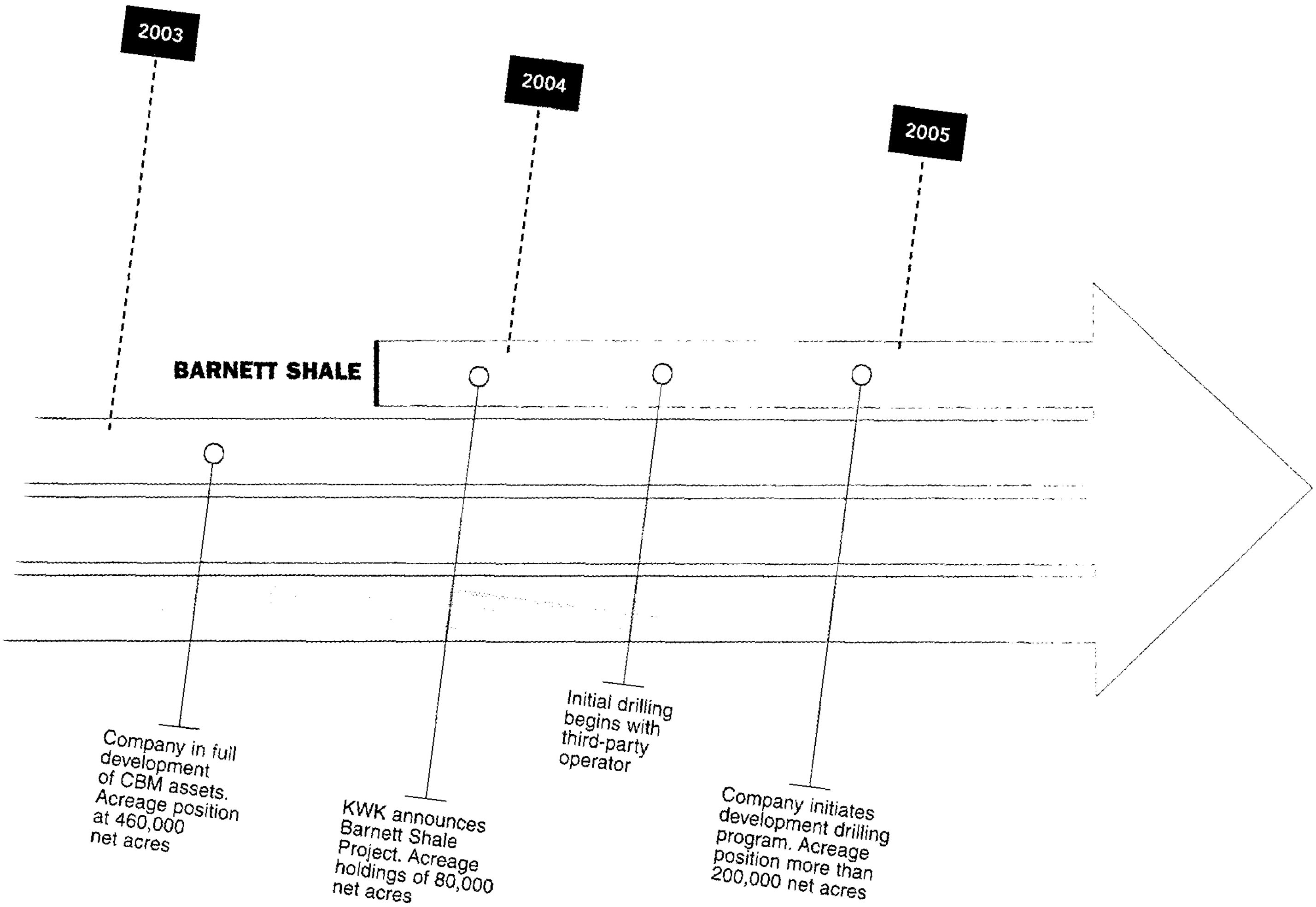
Originally begun in 2000, the New Albany Shale project in southern Indiana and northern Kentucky bears strong similarities to the Antrim Shale formation in Michigan. The company acquired 71 wells and has drilled 156 wells since 2000, including 37 wells in 2004. Estimated reserves per well range from 150 MMcf to 600 MMcf. Included in the initial acquisition was an eight-mile, 12-inch gas pipeline that runs from southern Indiana to northern Kentucky, and in the Fall of 2003, began transporting its New Albany Shale production through a pipeline extension that connects with the Texas Gas Pipeline, thus enabling the company to access gas markets in the Northeastern United States.

ESTIMATED INDIANA/KENTUCKY RESERVES AS OF 12/31/04	
Proved Developed Producing (PDP)	20.0 Bcfe
Proved Developed Nonproducing (PDNP)	1.9 Bcfe
Proved Undeveloped (PUD)	7.3 Bcfe
Total for Indiana/Kentucky	29.2 Bcfe

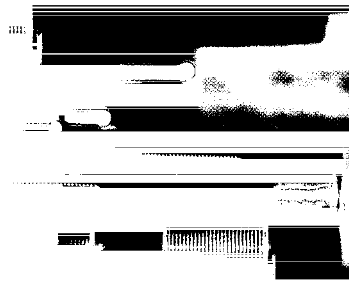
Quicksilver Resources anticipates drilling 10 wells, applying new technology techniques and further defining the producing fairway in 2005. The future development of the New Albany Shale area will benefit greatly from the lessons learned and the technology developed for the Barnett Shale and other areas.



LAYERED REVENUE STREAMS RESULT IN



SUSTAINABLE GROWTH & LONG-TERM SUCCESS



GAINING MOMENTUM, GROWING STRONG

QUICKSILVER RESOURCES ATTRIBUTES its extraordinary growth over the past six years to its unwavering adherence to a highly effective business model. In doing so, the company has successfully positioned itself as a leading player in unconventional natural gas, and it is writing its own playbook on how to succeed in this corner of the natural gas industry. Quicksilver Resources has successfully built one of the best unconventional gas teams in the business, with a deep bench of talent, possessing in-depth knowledge of the appropriate drilling and fracturing technologies and techniques, a rare sense of accountability in all operations, and a singular commitment.

AT QUICKSILVER RESOURCES, WE BELIEVE that we are bound by duty to our company, our customers, and our shareholders to succeed. As long as we put ourselves in the right places at the right times with the right expertise, Quicksilver will succeed.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2004

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ______ to ______.

COMMISSION FILE NUMBER: 001-14837

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

Delaware	75-2756163
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

777 West Rosedale, Suite 300
Fort Worth, Texas 76104
(Address of principal executive offices) (Zip Code)

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

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

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

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

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes [X] No [ ]

As of June 30, 2004, the aggregate market value of the voting stock held by non-affiliates of Quicksilver Resources Inc. was approximately $993,572,897 based on the New York Stock Exchange composite trading closing price of $33.53 on June 30, 2004. Shares of the registrant's voting stock owned by its directors, executive officers and certain Darden family members and related entities were excluded from this aggregate market value calculation; however, such exclusion does not represent a conclusion by the registrant that any or all of such directors, executive officers and certain Darden family members and related entities are affiliates of the registrant.

As of February 28, 2005, 50,233,180 shares of common stock of Quicksilver Resources Inc. were outstanding.

Documents incorporated by reference: Proxy statement of the registrant relating to the annual meeting of stockholders to be held on May 17, 2005 which is incorporated into Part III of this Form 10-K.

INDEX TO ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2004

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 two-for-one stock split effected in the form of a stock dividend in June 2004.

Quantities of natural gas are expressed in this report in terms of thousand cubic feet ("Mcf"), million cubic feet ("MMcf") or billion cubic feet ("Bcf"). 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 an independent oil and gas company engaged in the exploration, acquisition, development, production and sale of natural gas, crude oil and natural gas liquids ("NGLs") primarily from unconventional reservoirs such as fractured shales, coal beds and tight sands. We were organized as a Delaware corporation in 1999 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 and develop conventional oil and gas properties in the United States. As of December 31, 2004, members of the Darden family, together with Mercury and another entity entirely controlled by members of the Darden family, the sons and daughter of Frank Darden, beneficially owned approximately 37% of our outstanding common stock as of December 31, 2004. 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 Michigan, Indiana/Kentucky, Texas, the Rocky Mountains and the Canadian province of Alberta. At December 31, 2004, we had estimated proved reserves of 968 Bcfe. Approximately 92% of our reserves were natural gas, 77% were classified as proved developed and we operated approximately 70% of our reserves. Approximately 62% of our estimated proved reserves are located in Michigan and are characterized by long reserve lives and predictable well production profiles. For 2005, we expect to continue exploration and development of coal bed methane reserves in Alberta, Canada where approximately 27% of our proved reserves are located. We also expect to increase our exploration and development activities in the Barnett Shale of north Texas. We believe that much of our future growth will be through exploration and development of our interests in Canadian coal bed methane and north Texas Barnett Shale.

We intend to maintain an active capital-spending program that will focus primarily on the continued development and exploration of our coal bed methane properties in Canada and our Barnett Shale projects in north Texas. We also plan to continue the development and exploitation of our properties in Michigan and Indiana/Kentucky. For 2005, we have established a company-wide base capital budget of $235 million, with additional spending approved up to a maximum of $261 million. The discretion for additional expenditures will be based upon drilling and acreage acquisition opportunities in Texas and the success of horizontal drilling in Michigan, Indiana and Canada's Mannville coals. The maximum Canadian capital budget is approximately $107 million, which includes drilling approximately 497 wells (275 net), as well as construction of gathering lines, facilities and acreage acquisition. Approximately of $115 million of the United States capital budget will focus on north Texas where we expect to drill approximately 40 net Barnett Shale wells, construct gas plant facilities and phase one of the Cowtown Pipeline and acquire additional acreage. We also plan to dedicate approximately $38 million of the 2005 capital budget to our fractured shale projects in Michigan and Indiana/Kentucky. In both these areas, a portion of that budget will be spent for exploration activity that is intended to expand the known productive fairways.

The following table presents information regarding our primary areas of operation as of December 31, 2004:

Areas of Operations	Proved Reserves (Bcfe)	% Natural Gas	% Proved Developed	2004 Production (MMcfed)
Michigan	601.3	95%	90%	84.8
Canada	261.1	100%	57%	23.8
Indiana/Kentucky	29.2	100%	75%	5.9
Texas	36.7	60%	53%	0.5
Rockies	40.0	7%	41%	5.9
Total	968.3	92%	77%	120.9

We conduct our Canadian operations through our wholly owned subsidiary, MGV Energy Inc. ("MGV"). In 2000, we entered into a joint venture with EnCana Corporation ("EnCana") to explore for coal bed methane ("CBM") reserves on an area of over three million acres of land. In January 2003, MGV entered into an asset rationalization agreement with EnCana that divided the assets and rights subject to the joint venture. The agreement allowed us to pursue independent operations. Assets and rights received as a result of the agreement included an interest or an option to drill and earn in approximately 667,000 acres in Alberta. We have continued to acquire additional working interests in those areas as well as other areas in Alberta, Canada where we held approximately 423,000 net acres as of December 31, 2004. We also have the opportunity to earn in approximately 68,000 additional net acres.

Net gas sales from our CBM development projects in Alberta, Canada averaged 21.5 MMcfd in 2004. At year-end, the exit rate production from our CBM projects was approximately 35 MMcfd. During 2004, we drilled 319.8 productive net wells and connected those wells into existing infrastructure and pipeline systems to assure the control and priority of natural gas sales. As of December 31, 2004, we had 247.9 Bcf of proved reserves from our CBM projects in addition to 13.2 Bcf of proved reserves from our other Canadian natural gas interests.

During 2004, we began exploration and testing of the Barnett Shale formation in north Texas. We drilled eight 100%-owned wells in 2004 and anticipate drilling an additional 43 net wells in 2005. Three of the wells completed in 2004 were tied-in and producing at year-end. These three wells and four non-operated offset wells drilled in 2004 were producing within a range of 600 Mcfd to 2.8 MMcfd. As of December 31, 2004, we had 36.6 Bcfe of proved reserves from our Barnett Shale area and a net acreage position of approximately 207,000 acres.

Including 35 wells drilled in Indiana and Kentucky during 2004, we have 225 total wells and 29.2 Bcf of proved reserves from our New Albany Shale area. Including sales to a local end-user, our natural gas production averaged 5.9 MMcfd from the New Albany shale area. Our 12-mile Cardinal Pipeline, which transports our Indiana/Kentucky production to the interstate pipeline market, was placed into service at the end of September 2003 and allowed us to increase our exploration and development activities in the area.

During the third quarter, we sold certain natural gas and crude oil properties in Wyoming and Michigan. The divestitures were primarily crude oil reserves from properties in Wyoming with estimated proved reserves of 20 Bcfe. Net proceeds were approximately $8.3 million, net of closing adjustments. Also in the third quarter, we purchased additional interests in certain of our Antrim Shale properties in Michigan with approximately 5 Bcfe of proved reserves for approximately $10.4 million.

Business Strategy

Our business strategy is designed to achieve our principal objectives of growth in reserves, production and cash flow to increase stockholder value. Key elements of our business strategy include:

Focus on Unconventional Natural Gas Reserves. We focus our exploration and development efforts on unconventional natural gas reservoirs. Unconventional reservoirs such as natural gas produced from fractured shales, coal beds and tight sands will not produce at commercial flow rates unless the formation is successfully stimulated with fracturing. The majority of our Michigan production is from the Antrim Shale where we, and Mercury prior to our formation, have been active drillers and producers for over fifteen years. Our Antrim Shale activities have allowed us to develop a technical and operational expertise in the acquisition, development and production of unconventional natural gas reserves. Our Canadian CBM, New Albany Shale and Barnett Shale projects represent an extension of our expertise in unconventional natural gas reserves.

Low-Cost Development of Existing Property Base. We attempt to increase production and reserves through aggressive management of operations and relatively low-risk development drilling. Our principal properties possess geological and reservoir characteristics that make them well suited for production increases through exploitation activities and development drilling. We perform workovers and infrastructure improvement projects to reduce operating costs and increase current and ultimate production. We regularly review operations and mechanical data on operated properties to determine if additional actions can profitably be taken to increase reserves and production.

Pursuit of Selective Complementary Acquisitions. We seek to acquire long-lived producing properties with a high degree of operating control that contain opportunities to profitably increase natural gas and crude oil reserves and production levels through exploitation. Our reservoir enhancement techniques include the implementation of technically advanced reservoir management and aggressive cost management of field operations. We target acreage that we believe will expose us to high potential prospects located in areas that are geologically similar to neighboring areas with large developed fields. Consistent with our primary operating strategy, our acquisition focus is on unconventional reserves, including additional interests in properties we currently operate. Our significant operating position in Michigan uniquely positions us for further consolidation in that state through acquisitions that would provide additional economies of scale.

Management of Commodity Price Risk. We are focused on growing our oil and gas operations while seeking to moderate the effect of commodity price swings on net income and cash flow from operations. Our commodity price risk management strategy helps to ensure a predictable base level of cash flow, which enhances our ability to execute our drilling and exploitation programs, meet debt service requirements and pursue acquisition opportunities despite price fluctuations. 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. The sales contracts and financial hedges covered approximately 77% and 67% of our daily natural gas and crude oil production, respectively, or 68% of our total daily production, for the fourth quarter of 2004. As our five-year fixed price natural gas swaps terminate in 2005, we have begun to modify our hedging programs. We anticipate that those programs will make use of hedges with terms generally no longer than 12 to 18 months that allow us to realize a portion of any market increases in natural gas or crude oil prices over their term. Presently, about 50% of our budgeted 2005 natural gas production is hedged using the sales contracts and financial hedges. Additionally, almost 60% of our budgeted crude oil production for 2005 is hedged using price collars.

Participation in Exploratory Drilling Projects. We will continue to focus the bulk of our activities on lower risk exploitation activity and development drilling, including future activities in Canada; however, we will continue additional exploratory drilling in Canada, exploration and evaluation of the Barnett Shale formation in north Texas, and to pursue additional leasehold acquisitions and joint venture opportunities aimed at providing us with opportunities to explore for unconventional gas, including fractured shales, coal beds and tight sands, to which our technical and operational expertise is well suited.

Marketing

We sell natural gas 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, refineries and other users of petroleum products, and we are not dependent upon one purchaser or a small group of purchasers. Accordingly, the loss of a single purchaser in areas in which we sell natural gas or crude oil would not materially affect our sales. During 2004, the two largest purchasers of our total consolidated natural gas and crude oil sales were Encana Corporation and CoEnergy Trading Company.

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. Many competitors have financial and other resources, which substantially exceed ours. Our competitors in development, exploration, acquisitions and production include the major oil and gas companies as well as numerous independents and individual proprietors. Resources of our competitors may enable them to pay more for desirable leases and to evaluate, bid for and purchase a greater number of properties or prospects. Our ability to replace and expand our reserve base is dependent upon our ability to select and acquire suitable producing properties and prospects for future drilling.

Our acquisitions and exploration and drilling programs have been financed primarily through the issuance of debt and equity and internally generated cash flow. There is competition for capital to finance oil and gas acquisitions and drilling. Our ability to obtain such financing is uncertain and can be affected by numerous factors beyond our control. The inability to raise capital in the future could have an adverse effect on our business.

Governmental Regulation

Our operations are affected from time to time in varying degrees by political developments and United States 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 gas and crude oil exploration, development, production and pipeline gathering operations are subject to stringent United States 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 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 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 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 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 limitations 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 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.

Employees

As of March 1, 2005, we had 331 full time employees and 11 part time employees. There are no collective bargaining agreements in effect.

Executive Officers

The following information is provided with respect to our officers.

Name	Age	Position(s) Held With Quicksilver
Thomas F. Darden	51	Chairman of the Board
Glenn Darden	49	President, Chief Executive Officer and Director
Bill Lamkin	59	Executive Vice President and Chief Financial Officer
Jeff Cook	48	Senior Vice President—Operations
Mark D. Whitley	53	Vice President—Operations
Robert N. Wagner	41	Vice President—Reserve Group
D. Wayne Blair	48	Vice President and Controller
John C. Cirone	54	Vice President, General Counsel and Secretary
Anne Darden Self	47	Vice President—Human Resources and Director
J. Michael Gatens	46	Chairman of the Board and Chief Executive Officer—MGV Energy Inc.
George W. Voneiff	43	President—MGV Energy Inc.
Dana W. Johnson	45	Senior Vice President and Chief Operating Officer—MGV Energy Inc.
MarLu Hiller	42	Treasurer

The following biographies describe the business experience of our executive officers and the other officers named above.

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. 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. Mr. Darden graduated from Tulane University with a BA in Economics in 1975. 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 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 November 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 Corporation. He graduated from Tulane University in 1979 with a BA in Earth Sciences. 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 became our Chief Executive Officer in November 1999.

BILL LAMKIN is a Certified Management Accountant and a Certified Cash Manager with over 20 years of experience in the oil and gas industry. He graduated from Texas Wesleyan University with a BBA in Accounting in 1968. He served as Controller/Chief Financial Officer at Whittaker Corporation and Sargeant Industries, Inc. between 1970 and 1978. He worked as Treasurer, Controller, and Director of Financial Services at Union Pacific Resources from 1978 until he became our Executive Vice President and Chief Financial Officer when he joined us in June 1999.

JEFF COOK became our Senior Vice President Operations in 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 before joining us. Mr. Cook graduated from Texas Christian University with a BA in Finance in 1979.

MARK D. WHITLEY became our Vice President Operations in August 2003. He has more than 28 years of oil and gas production and operations experience including 20 years with Mitchell Energy Company LP, as its Vice President and General Manager of North Texas Production prior to its 2002 merger with Devon Energy. While at Devon from January 2002 to October 2002, Mr. Whitley served as Operations Manager – Fort Worth Basin and directed the production and operations activity in the exploration of the Fort Worth Basin's Barnett Shale gas play. After leaving Devon, he was an independent consultant until joining us. He graduated with a MS in chemical engineering from the University of Kentucky in 1975 after receiving his undergraduate degree from Worcester Polytechnic Institute.

ROBERT N. WAGNER was named as our Vice President Reserve Group 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. Mr. Wagner received a BS in Petroleum Engineering from the Colorado School of Mines in Golden, Colorado in 1986.

D. WAYNE BLAIR is a Certified Public Accountant with over 25 years of experience in the oil and gas industry. He graduated from Texas A&M University in 1979 with a BBA in Accounting. 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 and Controller, he was the Controller for Mercury from 1996.

JOHN C. CIRONE was named as our Vice President, General Counsel and Secretary on July 1, 2002. He graduated from St. Louis University School of Law in 1974 and 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.

ANNE DARDEN SELF has served on our board of directors since September 1999, and she became our Vice President-Human Resources in July 2000. She is also currently President of Mercury, where she has worked since 1992 as its Vice President Human Resources. 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. She attended Sweet Briar College and graduated from the University of Texas in Austin in 1980 with a BA in history.

J. MICHAEL GATENS is Chairman/CEO of MGV Energy Inc., which he co-founded in September 1997 in Calgary, Alberta. MGV became a wholly owned subsidiary of Quicksilver Resources Inc. in December 2000. Mr. Gatens is also Chairman of the Canadian Society for Unconventional Gas, and is MGV's liaison with the Coal Association of Canada and the Canadian Association of Petroleum Producers. Prior to starting MGV in 1997, he worked for S.A. Holditch & Associates, Inc. for 15 years, leaving as Director and Vice President of the Eastern Division in Pittsburgh. Mr. Gatens received BS and MS degrees in Petroleum Engineering from Texas A&M University in 1980 and 1987.

GEORGE W. VONEIFF co-founded MGV Energy Inc. in Calgary, Alberta in September 1997 to pursue unconventional gas opportunities, primarily in Western Canada. MGV became a wholly owned subsidiary of Quicksilver Resources Inc. in December 2000 and Mr. Voneiff continued in his role as President and Chief Operating Officer until January 2005 when he relinquished the role of Chief Operating Officer. Prior to founding MGV, he was with the petroleum consulting firm S.A. Holditch & Associates, Inc. from 1991 to 1997 and worked for Enserch Exploration Inc. from 1984 to 1990. Mr. Voneiff received BS and MS degrees in Petroleum Engineering from Texas A&M University in 1983 and 1991.

DANA W. JOHNSON became Senior Vice President and Chief Operating Officer of MGV Energy Inc. in January 2005. He joined us as U.S. Eastern Region Manager in early 2004 after serving 22 years in a variety of managerial, business development and engineering positions with Shell Exploration & Production Company. Mr. Johnson received a BS in Metallurgical Engineering from California Polytechnic State University in 1982 and a MBA from the University of Houston in 1992.

MARLU HILLER is a Certified Public Accountant with over 15 years of experience in public and oil and gas accounting. She graduated from Baylor University with a BBA in Accounting in 1985, and was with Ernst & Young for three years before joining Union Pacific Resources. At Union Pacific Resources, she served in various capacities, including financial reporting, financial system implementations, and manager of accounting for Union Pacific Fuels, which was Union Pacific Resources' marketing company. Ms. Hiller joined us in August of 1999 as Director of Financial Reporting and Planning and was named Treasurer in May of 2000.

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 or in any other of our filings with the Securities and Exchange Commission ("SEC") 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.

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, 2004, we had total consolidated debt of $399.5 million. Subject to the limits contained in the loan agreements governing our senior secured revolving credit facilities and our second lien mortgage 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 interest and principal payments under our senior secured revolving credit facilities and our second lien mortgage notes. 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, along with the financial and other restrictive covenants applicable to our indebtedness, among other things, our ability to borrow additional funds;
- 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 or second lien mortgage 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 comes due. Our future operating performance and ability to refinance will be affected by prevailing economic conditions at that time and financial, business 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 second lien mortgage notes restrict our ability and the ability of some of our subsidiaries to engage in certain activities that require the maintenance of specified financial ratios.

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

The loan agreements for our senior secured revolving credit facilities and second lien mortgage 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 and second lien mortgage notes 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 our inability to maintain the financial ratios described above could result in an event of default under our senior secured revolving credit facilities and/or our second lien mortgage notes. Upon the occurrence of such an event of default, the applicable lenders could, subject to the terms and conditions of the applicable security agreement, elect to declare all amounts outstanding under the applicable facility or notes, together with accrued interest, to be immediately due and payable. If we were unable to repay those amounts, the lenders could proceed against the collateral granted to them to secure such indebtedness. If our lenders accelerate the payment of our indebtedness, there can be no assurance that our assets would be sufficient to repay in full such indebtedness and our other indebtedness. The above restrictions could limit our ability to obtain future financing and may prevent us from taking advantage of attractive business opportunities.

Because we have a limited operating history in certain 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 cannot assure you that we will 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 credit facility is subject to periodic redetermination based in part on changing expectations of future prices. Lower prices may also reduce the amount of natural gas 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 wholesale price of natural gas rose from approximately $2.00 per thousand cubic feet in January of 2002 to over $10.00 in February of 2003. Among the factors that can cause this fluctuation are:

- the level of consumer product demand;
- weather conditions;
- domestic and foreign governmental regulations;
- the price and availability of alternative fuels;
- political conditions in oil and gas producing regions;
- the domestic and foreign supply of oil and gas;
- the price of foreign imports; and
- overall economic conditions.

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 such as 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, 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, 2004, approximately 23% 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, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the 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. A more accurate discount factor will take into consideration effective interest rates at the time of the valuation, estimated future prices and costs and consider the risks associated with us, our oil and gas reserves and the oil and gas industry in general.

Our key assets are concentrated in a small geographic area.

Approximately 70% of our 2004 production was from Michigan and approximately 20% was from Alberta, Canada. Because of our concentration in these geographic areas, any regional events that increase costs, reduce availability of equipment or supplies, reduce demand or limit production, including weather and natural disasters, may impact us more than if our operations were more geographically diversified.

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 MGV. At December 31, 2004 we estimated our proved Canadian reserves to be 261.1 Bcf. We expect MGV to continue the current pace of its scheduled activities, expand into other areas and increase its capital expenditures. Capital expenditures relating to MGV's operations are budgeted to be approximately $107 million in 2005, constituting approximately 41% of our total 2005 budgeted capital expenditures.

If our revenues decrease as a result of lower natural gas or crude oil prices or otherwise, we may have limited ability to maintain this level of capital expenditures. In the event additional capital resources are unavailable to us, we may curtail our acquisition, development drilling and other activities outside of Canada in order to keep pace with Canadian drilling activities. 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 our property drilling and acquisition activities. In the future, we will most 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, we may have limited ability to expend the capital necessary to replace our reserves or to maintain production at current levels, 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.

United States 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. According to customary industry practices, we maintain insurance against some, but not all, of such risks and losses. 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 necessarily 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, Indiana/Kentucky, Texas, the Rocky Mountains and Alberta, Canada, 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, which are primarily 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 where we can utilize our experience as a low-cost operator. 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 at low finding and development costs. 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 we do not operate.

As of December 31, 2004, other companies operated properties that included approximately 27% 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, 2004, other companies owned processing plants and pipelines that delivered approximately 63% of our natural gas production to market in Michigan. In addition, all of our Canadian natural gas production is transported through third party pipelines. As a result, 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. This risk was highlighted in 2003 by the shutdown of CMS Energy Inc. and Michigan Consolidated Gas Co. processing plants in Michigan that resulted in an approximate 725 Mmcf decrease in our 2003 production.

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

Our operations are dependent on a relatively small group of key management and technical personnel. We cannot assure you that these individuals will remain with us for the immediate or foreseeable future. The unexpected 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 operate and develop 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 in 2004 for the sale of approximately 28% of our natural gas production and for a significant portion of our total revenues. 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 long-term natural gas and crude oil hedging arrangements. These hedging arrangements expose us to risk of financial loss 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.

In addition, these hedging arrangements may limit the benefit we would receive from increases in the prices for natural gas and crude oil in the following instances:

- there is a change in the expected difference between the underlying price in the hedging agreement and actual prices received; or
- a sudden unexpected event materially impacts natural gas or crude oil prices.

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 production month's end. 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.

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 United States 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.

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 Mercury and Quicksilver Energy, L.P., entities primarily owned by members of the Darden family, beneficially own on the date of this annual report approximately 37% 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 stock. There were 50,122,360 shares of our common stock outstanding at December 31, 2004, including 172,626 shares issuable upon exchange of exchangeable shares issued by MGV. Approximately 30,608,710 of these shares are freely tradable without substantial restriction or the requirement of future registration under the Securities Act. In addition, at December 31, 2004 we had the following options outstanding to purchase shares of our common stock:

- Options to purchase 325,424 shares at $1.844 per share;
- Options to purchase 47,536 shares at $4.90 per share;
- Options to purchase 80,556 shares at $8.02 per share;
- Options to purchase 8,800 shares at $8.25 per share;
- Options to purchase 55,436 shares at $8.51 per share;
- Options to purchase 55,486 shares at $11.04 per share;
- Options to purchase 32,336 shares at $12.05 per share;
- Options to purchase 561,430 shares at $16.515 per share;
- Options to purchase 15,384 shares at $23.75 per share;
- Options to purchase 1,183,422 shares at $31.27 per share; and
- Options to purchase 69,760 shares at $35.75 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.

Internet Website

We file annual, quarterly and special reports, proxy statements and other information with the SEC. Our SEC filings are available to the public over the Internet at the SEC's web site at http://www.sec.gov. You may also read and copy any document we file at the SEC's public reference room at 450 Fifth Street, N.W., Washington, D.C. 20549. You may obtain information on the operation of the SEC's public reference room in

Washington, D.C. by calling the SEC at 1-800-SEC-0330. 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.

ITEM 2. Properties

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

Michigan

Producing Formation	Proved Reserves (Bcfe)	% Gas	% Proved Developed	2004 Production (MMcfed)
Antrim Shale	522.8	100%	91%	59.7
Non-Antrim	78.5	65%	82%	25.1
All Formations	601.3	95%	90%	84.8

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 generally allows Michigan producers to sell their natural gas at a slight premium to typical industry benchmark prices.

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. 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, 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.

At December 31, 2004, we owned working interests in 2,956 producing Antrim wells and operated 50% of those wells. Since 1998, we have drilled 479 Antrim wells and successfully completed 473 for a success rate of 99%. In 2004, we drilled and successfully completed 44.3 (net) Antrim wells. For 2005, we have budgeted for the drilling of 51 (net) Antrim wells, including several horizontal wells.

Our non-Antrim reserves include interests in several reservoirs that include the Prairie du Chien ("PdC"), Garfield Richfield, Detroit River Zone III (DRZ3") and Niagaran pinnacle reefs. Our PdC wells produce from several Ordovician age reservoirs with the majority being in the 1,000 feet to 1,200 feet thick PdC Group that has three major sands: the Lower PdC, Middle PdC and Upper PdC. Many of these wells also can produce from the

St. Peter sandstone and the Glenwood formations, both of which lie directly above the PdC. Some of the wells are producing from two or more of these zones. 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 three development wells were drilled in 2003 and 2004 to increase production from existing fields. At year-end we had 32 gross (25.9 net) PdC wells producing. 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 Richfield zone consists of seven dolomite reservoirs spread over a 200-foot interval. The Garfield Richfield has seven wells producing under primary solution gas drive. Additional potential exists in the Garfield Richfield either by secondary waterflood and/or improved oil recovery with CO2 injection. The potential upside is under evaluation and has not been included in our booked reserves. The Beaver Creek Richfield is currently being waterflooded, with 96 producing wells and 58 water injection wells.

The Detroit River Zone III ("DRZ3") at Beaver Creek lies approximately 200 feet above the Richfield. The DRZ3 is a six-foot dolomite zone that covers approximately 10,000 acres on the Beaver Creek structure. We had 28 producing wells as of December 31, 2004. While there is the opportunity for improving production and proved reserve quantities, we have determined that our resources are better allocated to continued exploration and development of our many unconventional gas projects.

Our Niagaran wells produce from numerous Silurian-age Niagaran pinnacle reefs located in nine counties in Northern Michigan. The depth of these wells range from 3,400 feet to 7,800 feet with reservoir thickness from 300 feet to 600 feet. 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. As of December 31, 2004, we had 68 gross (31.7 net) producing Niagaran wells.

Canada

In 2000, we began to focus on the potential of Canadian CBM through MGV. 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 the province of Alberta. By January 2003, the joint venture had drilled 175 exploratory, pilot and development wells. 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, we have drilled 468.3 successful net wells, most as operator, including significant developments in the Gayford and Beiseker areas. By December 31, 2004, we had proved reserves of 247.9 Bcf from our CBM projects and had ongoing field operations in all our joint ventures.

During 2005, we expect to drill 497 wells (275 net) and install nine new CBM facilities. Each plant will be capable of processing five to ten MMcfd of natural gas production. A portion of our 2005 capital budget of $107 million will be committed to CBM drilling including testing of the Mannville coals.

Including its interests in other conventional natural gas properties located in southern Alberta, MGV held interests in 1,266 gross (572.3 net) wells as of December 31, 2004. Our total Canadian proved reserves at December 31, 2004 were estimated to be 261.1 Bcf including 13.2 Bcf from our conventional gas properties. Our average daily production in Canada for 2004 was 23.8 MMcfd. As of December 31, 2004, however, we had increased total Canadian production to approximately 38 MMcfd.

Indiana/Kentucky

In 2000, we acquired a 100% working interest in 36 New Albany Shale producing wells. Included with the acquisition of these producing wells, we also acquired the eight-mile 12-inch GTG gas pipeline that runs from southern Indiana to northern Kentucky. We acquired 35 wells in 2003. At December 31, 2004, we had 192 producing wells in Indiana/Kentucky. In September 2003, we commenced transportation of New Albany production through a pipeline extension that connects to the Texas Gas Pipeline in northern Kentucky. Natural gas sales from our properties in the area averaged 5.9 MMcfd during 2004.

Texas

During 2004, we began testing and exploration in the Barnett Shale of north Texas. As of December 31, 2004, we had completed drilling on eight 100%-owned wells and owned non-working interests in four others wells. Initial production rates from the first wells completed ranged from 600 Mcfd to 1.8 MMcfd. Modifications to the fracturing techniques have resulted in improvements in each successive well drilled. Initial rates from the last four operated wells have ranged from 2.0 to 2.8 MMcfd. As of December 31, 2004, our production from the Barnett Shale was approximately 1 MMcfd. Our wells are spread over an area stretching from northwest Johnson County to southeastern Hood County, approximately 20 miles in a north-south direction and we held approximately 207,000 net acres in the Barnett Shale play as of year-end.

Our plans for 2005 include drilling approximately 40 net wells in the Barnett Shale and beginning on construction of the initial phase of the Cowtown Pipeline in the second quarter of 2005. This pipeline will transport both Quicksilver and third party volumes. In addition, we plan to install a natural gas liquids extraction plant that will be operational in the fourth quarter of 2005.

Rocky Mountain Region

Our Rocky Mountain properties are located in Montana and Wyoming. Production from those properties is primarily crude oil that is from well-established producing formations at depths ranging from 1,000 feet to 17,000 feet. As of December 31, 2004, our Rocky Mountain proved reserves were 6.0 MMbbls of crude oil and 4.0 Bcfe of natural gas and NGLs for total equivalent reserves of 40.0 Bcfe after our third quarter divestiture of properties with reserves of approximately 3.4 MMbbls of crude oil and 0.2 Bcfe of natural gas. In 2004, our daily production averaged 5.9 MMcfed. After the sale of most of our Wyoming properties in the third quarter of 2004, fourth quarter production averaged 3.4 MMcfed.

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, LaRoche Petroleum Consultants, Ltd. and Netherland, Sewell & Associates, Inc. prepared our reserve estimates. 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 only by contractual arrangements, but not on escalations based upon future conditions. Prices do not include the effect of derivative instruments we have entered into. Future production and development costs include production and property taxes.

Proved developed oil and gas reserves are reserves that can be 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, 2004, 2003 and 2002.

	Years Ended December 31, Total Proved Reserves			Years Ended December 31, Proved Developed Reserves		
	2004	2003	2002	2004	2003	2002
Natural gas (MMcf)						
United States	627,676	643,520	637,983	556,999	569,979	550,889
Canada	261,077	146,632	53,602	149,453	83,698	22,750
Total	888,753	790,152	691,585	706,452	653,677	573,639
Crude oil (MBbl)						
United States	9,067	13,173	16,002	4,587	8,734	10,722
Canada	—	—	—	—	—	—
Total	9,067	13,173	16,002	4,587	8,734	10,722
NGL (MBbl)						
United States	4,187	1,918	2,216	2,464	1,405	1,524
Canada	—	—	—	—	—	—
Total	4,187	1,918	2,216	2,464	1,405	1,524
Total (MMcfe)	968,276	880,696	800,893	748,762	714,511	647,115

	Year Ended December 31, 2004	2003	2002
Representative crude oil and natural gas prices: (1)			
Natural gas—Henry Hub Spot	$ 6.18	$ 5.97	$ 4.74
Natural gas—AECO	5.18	5.32	2.92
Crude oil—WTI Cushing	43.36	32.55	31.20
Present values (in thousands): (2)			
Standardized measure of discounted future net cash flows, before income tax	$1,344,278	$1,200,650	$867,748
Standardized measure of discounted future net cash flows, after income tax	$ 970,731	$ 848,741	$614,851

(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, with these representative prices adjusted by local differentials to arrive at the appropriate corporate net price.

(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,		
	2004	2003	2002
Production:			
Natural gas (MMcf)			
United States	30,644	31,612	31,910
Canada	8,707	2,924	935
Total natural gas	39,351	34,536	32,845
Crude oil (MBbl)			
United States	689	807	905
Canada	—	1	—
Total crude oil	689	808	905
NGL (MBbl)			
United States	128	133	156
Canada	1	2	—
Total NGL	129	135	156
Total production (Mmcfe)	44,257	40,192	39,209
Average Prices (including impact of hedges):			
Natural gas—per Mcf			
United States	$ 3.52	$ 3.32	$ 2.77
Canada	4.92	3.98	2.13
Consolidated	3.83	3.38	2.75
Crude oil—per Bbl			
United States	$ 33.07	$ 24.23	$ 21.74
Canada	—	24.46	—
Consolidated	33.07	24.23	21.74
NGL—per Bbl			
United States	$ 28.55	$ 21.45	$ 14.97
Canada	22.18	26.01	—
Consolidated	28.52	21.50	14.97
Average Prices (excluding impact of hedges):			
Natural gas—per Mcf			
United States	$ 4.86	$ 4.50	$ 2.99
Canada	4.98	4.15	2.22
Consolidated	4.89	4.47	2.97
Crude oil—per Bbl			
United States	$ 36.53	$ 26.69	$ 21.86
Canada	—	24.46	—
Consolidated	36.53	26.69	21.86
NGL—per Bbl			
United States	$ 28.55	$ 21.45	$ 14.97
Canada	22.18	26.01	—
Consolidated	28.52	21.50	14.97
Production cost (per Mcfe)(1)			
United States	$ 1.54	$ 1.29	$ 1.06
Canada	1.19	1.35	1.84
Consolidated	1.47	1.30	1.08

(1) Includes production 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,					
	2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Development:						
United States						
Productive	73.0	55.5	102.0	74.3	106.0	81.2
Non-productive	—	—	—	—	1.0	1.0
Canada						
Productive	356.0	110.1	32.0	32.0	17.0	17.0
Non-productive	—	—	—	—	—	—
Total	429.0	165.6	134.0	106.3	124.0	99.2
Exploratory:						
United States						
Productive	38.0	34.2	76.0	73.3	24.0	22.9
Non-productive	1.0	1.0	1.0	1.0	3.0	3.0
Canada						
Productive	274.0	209.7	152.0	116.5	44.0	26.2
Non-productive	10.0	9.8	1.0	0.4	—	—
Total	323.0	254.7	230.0	191.2	71.0	52.1
Total:						
Productive	741.0	409.5	362.0	296.1	191.0	147.3
Non-productive	11.0	10.8	2.0	1.4	4.0	4.0
Total	752.0	420.3	364.0	297.5	195.0	151.3

Acquisition, Exploration and Development Capital Expenditures

	United States	Canada	Consolidated
		(in thousands)	
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
2003			
Proved acreage	$ 3,215	$ 3,388	$ 6,603
Unproved acreage	24,063	6,739	30,802
Development costs	37,682	41,820	79,502
Exploration costs	9,411	17,066	26,477
Total	$ 74,371	$ 69,013	$143,384
2002			
Proved acreage	$ 32,199	$ —	$ 32,199
Unproved acreage	550	5,422	5,972
Development costs	34,178	938	35,116
Exploration costs	5,925	8,659	14,584
Total	$ 72,852	$ 15,019	$ 87,871

Productive Oil and Gas Wells

The following table summarizes productive oil and gas wells attributable to our direct interests as of December 31, 2004:

	As of December 31, 2004 Productive Wells			
	Natural Gas		Crude Oil	
	Gross	Net	Gross	Net
United States	4,996	1,658.8	406	367.6
Canada	1,263	572.2	3	0.1
Total	6,259	2,231.0	409	367.7

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 following table indicates our interest in developed and undeveloped acreage held directly by us. Developed acres are defined as acreage spaced or allocated to wells that are producing or capable of producing. Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or 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, 2004			
	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Michigan	584,856	240,944	65,568	46,030
Indiana/Kentucky	42,288	42,160	228,686	222,399
Texas	7,665	4,675	306,172	266,296
Rockies	109,934	100,921	176,378	133,631
United States	744,743	388,700	776,804	668,356
Canada	149,181	90,992	451,597	331,274
Total	893,924	479,692	1,228,401	999,630

ITEM 3. Legal Proceedings

In August 2001, a group of royalty owners, Athel E. Williams et al., brought suit against us and three of our subsidiaries in the Circuit Court of Otsego County, Michigan. The suit alleges that Terra Energy Ltd, one of our 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. The court heard arguments on class certification on November 8, 2002, and on December 6, 2002 the court issued a memorandum opinion granting class certification in part and denying it in part. On December 20, 2002, we filed a motion for clarification and reconsideration of the court's order. That motion was denied on March 9, 2003. After an extended delay resulting from the retention of new counsel by the plaintiffs and the initiation of settlement discussions, on January 21, 2005, the Circuit Court issued an order certifying certain claims to proceed on behalf of a class. The Circuit Court also entered a scheduling order setting trial for January 2007, and declined Defendants' request to stay proceedings in that court pending an appeal of the certification order.

Defendants have sought leave to appeal the certification order by filing an Application for Leave to Appeal on February 11, 2005 with the Michigan Court of Appeals. Defendants have also requested that the Court of Appeals stay proceedings in the Circuit Court pending the consideration of its appeal, and have requested that the Court of Appeals consider all matters in an expedited manner. We are currently awaiting a ruling from that court on the application and the requests for stay and immediate consideration.

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 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 2004.

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
2004 (1)		
Fourth Quarter	$37.88	$28.97
Third Quarter	36.12	25.29
Second Quarter	33.70	18.73
First Quarter	21.35	16.04
2003 (1)		
Fourth Quarter	$16.83	$12.20
Third Quarter	13.08	11.47
Second Quarter	13.06	11.23
First Quarter	12.22	9.77

(1) Stock prices been have adjusted to reflect a two-for-one stock split effected in the form of a stock dividend in June 2004.

As of February 28, 2005, there were approximately 488 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.

ITEM 6. Selected Financial Data

The following tables set 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

(in thousands, except for per share data)

	Years Ended December 31,				
	2004	2003	2002	2001	2000
Consolidated Statements of Income Data:					
Total revenues	$ 179,729	$ 140,949	$121,979	$ 141,963	$ 118,392
Income before income taxes	45,446	28,502	21,333	30,110	27,731
Income before cumulative effect of change in accounting principle	31,272	18,505	13,835	19,310	17,618
Net income	31,272	16,208	13,835	19,310	17,618
Earnings—per share before accounting change (1)					
Basic	$ 0.63	$ 0.41	$ 0.35	$ 0.52	$ 0.48
Diluted	0.62	0.41	0.34	0.50	0.48
Earnings—per share (1)					
Basic	$ 0.63	$ 0.36	$ 0.35	$ 0.52	$ 0.48
Diluted	0.62	0.35	0.34	0.50	0.48
Consolidated Statements of Cash Flows Data:					
Net cash provided by (used in):					
Operating activities	$ 99,449	$ 59,280	$ 44,198	$ 57,921	$ 47,691
Investing activities	(220,500)	(147,422)	(83,659)	(67,227)	(195,518)
Financing activities	134,389	79,369	40,050	5,199	158,103
Capital expenditures	$ 231,757	$ 148,488	$ 88,965	$ 67,566	$ 194,507
Consolidated Balance Sheets Data:					
Working capital (deficit) (2)	$ (17,255)	$ (30,803)	$ (23,678)	$ (19,141)	$ 935
Properties—net	802,610	604,576	470,078	412,455	374,099
Total assets	888,334	666,934	529,538	471,884	440,111
Long-term debt	399,134	249,097	248,493	248,425	239,986
Stockholders' equity	304,276	241,816	128,905	94,387	86,758

(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.

(2) Working capital includes the current portion of assets and liabilities, which reflect estimated fair value of derivative obligations.

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 Quicksilver Resources Inc. 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 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 operate in one business – exploration, development and production of natural gas, crude oil and NGLs. Except to the extent those differences between our two geographic operating segments are material to an understanding of our business as a whole, we present the discussion to this MD&A on a consolidated basis.
- *Liquidity and Capital Resources*—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 an independent oil and gas company engaged in the exploration, acquisition, development, production and sale of natural gas, crude oil and natural gas liquids primarily from unconventional reservoirs such as fractured shales, coal beds and tight sands. We generate revenue, income and cash flows by producing and selling natural gas, crude oil and natural gas liquids. We produce these products in quantities and at prices that, in addition to generating operating income, allow us to conduct exploration, development and acquisition activities to replace the reserves that have been produced.

At December 31, 2004, approximately 92% of our proved reserves were natural gas. Our Michigan reserves make up approximately 62% of those reserves. Our Michigan activities in the Antrim shale have allowed us to develop a technical and operational expertise in the acquisition, development and production of unconventional natural gas reserves. Consistent with one of our business strategies, we have applied our expertise gained in our Michigan activities to our Canadian coal bed methane ("CBM") projects in Alberta, Canada. Our Canadian reserves made up about 27% of our proved reserves at December 31, 2004. Our Indiana/Kentucky New Albany Shale and Texas Barnett Shale projects represent additional extensions of that expertise.

For 2005, we plan to continue our focus on the exploration and development of CBM properties in Alberta, Canada and our Barnett Shale acreage in Texas. We expect budgeted capital expenditures in 2005 to be as much as $261 million, of which about $107 million is allocated to our Canadian CBM projects and approximately $115 million is allocated to our Barnett Shale position in north Texas. The remainder is allocated to our fractured shale projects in Michigan and Indiana/Kentucky.

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 exploration and development of unconventional natural gas reservoirs. We strive to increase reserves and production through aggressive management of operations and relatively low-risk development drilling. We will also continue to identify high potential exploratory projects with higher levels of financial risk. Both our low-risk development programs and exploratory projects are aimed at providing the Company with opportunities to explore for, and develop, unconventional natural gas reservoirs to which our technical and operational expertise is well suited.

Our principal properties are well suited for production increases through exploitation activities and development 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 these key measurements: earnings; cash flow from operating activities; production and overhead costs per unit of production; production volumes; reserve growth; and finding costs per unit of reserve addition.

	Years Ended December 31,		
	2004	2003	2002
		(in thousands)	
Operating income	$60,693	$48,498	$40,702
Cash flow from operations	99,449	59,280	44,198
Production cost per mcfe (1)	$ 1.24	$ 1.08	$ 0.94
General and administrative cost per mcfe	0.29	0.20	0.19
Production (MMcfe)	44,257	40,192	39,209

(1) Excludes production taxes.

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 Quicksilver to participate in all, or a portion, of any favorable price increases. This commodity price strategy enhances our ability to execute our drilling 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 development and exploratory drilling and acquisition activities. We might also be forced to sell some of our assets on an untimely or unfavorable basis.

Natural gas prices were favorable throughout 2004 and 2003 and industry analysts expect them to remain favorable for the foreseeable future. With continued favorable gas prices, the expiration of our remaining fixed price natural gas hedges in April 2005 and increasing natural gas production, we expect to fund more of our capital expenditures with cash flow from operations; however, we do not expect our cash flow from operations to be sufficient to satisfy our total budgeted capital expenditures. We plan to use cash flows from operations, credit facility utilization and possible issuance of debt or equity securities to fund our total budgeted capital expenditures in 2005.

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 sell approximately 25,000 Mcfd and 10,000 Mcfd of natural gas under long-term contracts with floor prices of $2.49 per Mcf and $2.47 per Mcf, respectively, through March 2009. Approximately 5,300 Mcfd sold under these contracts in 2004 were third party volumes controlled by us. We also enter into financial contracts to hedge our exposure to commodity price risk associated with anticipated future natural gas and crude oil production. These contracts have included price ceilings and floors, no-cost collars and fixed price swaps.

Natural gas sales volumes of 30,000 Mcfd are hedged for the first four months of 2005 using fixed price swap agreements entered into in May 2000. The weighted average price for natural gas volumes under those agreements is $2.79. Natural gas price collars hedge approximately 20,000 Mcfd of our budgeted natural gas sales volumes for the first quarter of 2005. Natural gas price collars hedge nearly 33,000 Mcfd of our budgeted natural gas sales volumes for the remainder of 2005. Additionally, price collars hedge approximately 750 Bbld of our 2005 budgeted crude oil sales.

The following table summarizes our open financial derivative positions as of December 31, 2004 related to 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 2005-Apr 2005	10,000 Mcfd	$2.79	$(4,016)
Gas	Swap	Jan 2005-Apr 2005	10,000 Mcfd	2.79	(4,025)
Gas	Swap	Jan 2005-Apr 2005	10,000 Mcfd	2.79	(4,025)
Gas	Collar	Jan 2005-Mar 2005	5,000 Mcfd	5.50-9.60	62
Gas	Collar	Jan 2005-Mar 2005	10,000 Mcfd	5.50-9.63	115
Gas	Collar	Jan 2005-Mar 2005	5,000 Mcfd	5.50-9.90	86
Gas	Collar	Apr 2005-Oct 2005	5,000 Mcfd	5.50-6.75	(109)
Gas	Collar	Apr 2005-Oct 2005	10,000 Mcfd	5.50-6.75	(219)
Gas	Collar	May 2005-Oct 2005	15,000 Mcfd	5.50-7.15	(15)
Gas	Collar	May 2005-Oct 2005	5,000 Mcfd	6.50-8.15	624
Gas	Collar	May 2005-Oct 2005	5,000 Mcfd	6.50-8.22	632
Gas	Collar	Nov 2005-Mar 2006	10,000 Mcfd	6.50-11.20	779
Gas	Collar	Nov 2005-Mar 2006	10,000 Mcfd	6.50-11.20	779
Gas	Collar	Apr 2006-Oct 2006	5,000 Mcfd	5.50-8.10	332
Gas	Collar	Apr 2006-Oct 2006	5,000 Mcfd	5.50-8.25	339
Oil	Collar	Jan 2005-Jun 2005	500 Bbld	40.00-52.80	93
Oil	Collar	Jan 2005-Jun 2005	500 Bbld	40.00-46.75	(5)
Oil	Collar	Jul 2005-Dec 2005	250 Bbld	38.00-47.75	13
				Net open positions	$ (8,560)

Utilization of our financial hedging program may result in realization of natural gas and crude oil prices that vary from the actual prices that we receive from the sale of natural gas and crude oil. As a result of the hedging programs, revenues from production were lower than if the hedging programs had not been in effect by $43.9 million in 2004, $39.8 million in 2003 and $7.4 million in 2002.

Commodity price fluctuations affect our remaining natural gas and crude oil volumes as well as our NGL volumes. Up to 4,500 Mcfd of natural gas is committed at market price through May 2005. Additional natural gas volumes of 16,500 Mcfd are committed at market price through September 2008. During 2004, approximately 6,400 Mcfd of our natural gas production was sold under these contracts. The remaining Mcfd contractual volumes were third-party volumes controlled by us.

Based on our 2004 average production and long-term natural gas sales contracts with floor prices of $2.49 per Mcf and $2.47 per Mcf, and our 2004 average production, each $1.00 per Mcf increase/decrease in the price of natural gas would increase/decrease our revenue by approximately $28.1 million. Should additional revenue of $28.1 million be realized, approximately $3.6 million would be required for settlement of our remaining fixed price hedges.

We have entered into various financial contracts to hedge exposure to commodity price risk associated with future contractual natural gas sales and purchases with derivative instruments. These contracts include either fixed and floating price sales to, or purchases from, third parties. As a result of these firm sale and purchase commitments and associated financial price swaps, the hedge derivatives qualified as fair value hedges for accounting purposes. Marketing revenues were $0.5 million and $0.3 million higher and lower by $2.2 million as a result of our hedging activities in 2004, 2003 and 2002, respectively. Hedge ineffectiveness resulted in $118,000 of net losses, $188,000 of net gains and $26,000 net losses recorded to other revenue for 2004, 2003 and 2002, respectively.

The following table summarizes our open financial derivative positions and hedged firm commitments as of December 31, 2004 related to natural gas marketing.

Contract Period	Volume	Weighted Avg Price per Mcf	Fair Value
			(in thousands)
Natural Gas Sales Contracts			
Jan 2005	2,262 Mcfd	$ 7.74	$ 104
Feb 2005	3,935 Mcfd	$ 7.53	136
Mar 2005	1,935 Mcfd	$ 7.58	74
			$ 314
Natural Gas Financial Derivatives			
Jan 2005-Mar 2005	1,333 Mcfd	Floating Price	$(171)
Jan 2005-Mar 2005	333 Mcfd	Floating Price	(44)
Jan 2005	645 Mcfd	Floating Price	(35)
Feb 2005	1,428 Mcfd	Floating Price	(43)
Feb 2005	714 Mcfd	Floating Price	(17)
Mar 2005	323 Mcfd	Floating Price	(12)
			(322)
		Total-net	$ (8)

The fair value of fixed price and floating price natural gas and crude oil derivatives and associated firm commitments as of December 31, 2004 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 to assume our contract positions.

Interest Rate Risk

We manage our exposure associated with interest rates by entering into interest rate swaps. As of December 31, 2004, the interest payments for $75.0 million notional variable-rate debt are hedged with an interest rate swap that converts a floating three-month LIBOR base to a 3.74% fixed-rate through March 31, 2005. Our liability associated with the swap was $0.2 million at December 31, 2004 and $2.0 million at December 31, 2003.

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 is being recognized over the original term for the swap, which ends December 31, 2006. A deferred gain of $0.2 million remains at December 31, 2004.

Interest expense for the years ended December 31, 2004, 2003 and 2002 was $0.8 million, $1.4 million and $2.6 million higher, respectively, as a result of the interest rate swaps.

If interest rates on our variable interest-rate debt of $112.8 million, as of February 28, 2004, and $75 million of variable rate debt hedged through March 31, 2005 increase or decrease by one percentage point, our annual pretax income will decrease or increase by $1.7 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 1. Business—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. During October and November 2004, Quicksilver loaned MGV approximately $11.4 million. To reduce its exposure to exchange rate risk, MGV 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, MGV recognized a gain of $0.2 million.

While cross-currency transactions are minimized, the result of a ten percent change in the Canadian-U.S. exchange rate would increase or decrease equity by approximately $6.4 million at December 31, 2004.

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 employ the full cost method of accounting for our oil and gas properties. Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties are capitalized and accumulated in cost centers on a country-by-country basis. This includes any internal costs that are directly related to exploration and development 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.

Net capitalized costs are limited to the lower of unamortized cost net of related 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 our 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 costs being amortized less (iv) income tax effects related to differences between the book and tax basis of the oil and gas properties. Such limitations are imposed separately for the U.S. and Canadian cost centers.

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 include financial derivatives that hedge our oil and gas revenue.

The Company's estimates of proved reserves are made using available geological and reservoir data as well as production performance data. These estimates, made by the Company's 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 DD&A rate calculation and the financial statements.

Ceiling Test

Companies that use the full cost method of accounting for oil and gas properties are required to perform the ceiling test each quarter. The ceiling is an impairment test performed on a country-by-country basis as prescribed by SEC Regulation S-X Rule 4-10. The test determines a limit, or ceiling, on the book value of oil and gas properties. That limit is basically 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. This ceiling is compared to the net book value of the 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 ceiling, an impairment or noncash writedown is required. A ceiling test impairment can give the Company 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, 2004, capitalized costs, inclusive of future development costs, for U.S. and Canadian reserves were $1.18 per Mcfe and $0.78 per Mcfe, respectively.

Derivative Instruments

We enter into financial derivative instruments to hedge risk associated with the prices received from natural gas and crude oil production and marketing. 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 that meet 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.

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, 2004, our revenues for 2005 will decrease approximately $10.2 million and interest expense will increase approximately

$0.2 million. Net income, after income taxes, will be approximately $6.8 million lower. These amounts will be reclassified from accumulated other comprehensive income in 2005.

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 Statement of Financial Accounting Standard ("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.

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. MGV, 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 MGV and thus are not considered available for distribution to the parent Company.

Included in our net deferred tax liability are $51.8 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 meanings of Item 303(a)(4) of SEC Regulation S-K.

RESULTS OF OPERATIONS

Summary Financial Data
Years Ended December 31, 2004, 2003 and 2002

	Years Ended December 31,		
	2004	2003	2002
		(in thousands)	
Total operating revenues	$179,729	$140,949	$121,979
Total operating expenses	120,214	93,782	81,477
Operating income	60,693	48,498	40,702
Income before accounting change	31,272	18,505	13,835
Net income	31,272	16,208	13,835

Net income for each of the years ending December 31, 2004, 2003 and 2002 was $31.3 million ($0.62 per diluted share), $16.2 million ($0.35 per diluted share) and $13.8 million ($0.34 per diluted share), respectively. Included in 2003 was a $2.3 million charge ($0.05 per diluted share), net of tax, for the adoption of SFAS No. 143, *Accounting for Asset Retirement Obligations*, as of January 1, 2003. The 2003 period also included a $3.8 million pre-tax charge ($2.5 million after tax) to interest expense as a result of our early redemption of $53 million in principal amount of our subordinated notes payable.

Operating Revenues

Our 2004 revenues were $179.7 million as compared to $141.0 million for 2003, primarily as a result of additional Canadian revenue in 2004. The additional Canadian revenue was from a 5,776,000 net Mcfe increase in Canadian production from coal bed methane ("CBM") projects and a 24% increase in realized prices. U.S. production revenue increased by approximately 5% over 2003 revenue with an 11% increase in realized prices being partially offset by a decrease in production of 1,711,000 Mcfe.

Total revenues for 2003 were $141.0 million, a $19.0 million increase from the $122.0 million reported in 2002. Higher realized prices and additional sales volumes increased revenue $26.7 million. The increase was primarily the result of sales volumes added from our Canadian CBM development projects and an 84% increase in Canadian realized sales prices. Additionally, U.S. realized prices increased approximately 19%. Additional revenue associated with U.S. prices increases was partially offset by an approximately 1,000,000 Mcfe decrease in U.S. sales volumes. Other revenue for 2003 was $7.8 million lower from the prior year. Revenue of $5.1 million was recognized from the sale of Section 29 tax credits in 2002. The tax credits expired in 2002. In 2003, a $0.5 million decrease in other revenue was the result of the completion of our negotiations to purchase the tax credit properties.

Gas, Oil and NGL Sales

Our sales volumes, revenues and average prices for the years ended December 31, 2004, 2003 and 2002 are as follows:

	Years Ended December 31,		
	2004	2003	2002
Average daily sales volume			
Natural gas—Mcfd			
United States	83,727	86,608	87,425
Canada	23,789	8,011	2,563
Total	107,516	94,619	89,988
Crude oil—Bbld			
United States	1,882	2,212	2,479
Canada	—	1	—
Total	1,882	2,213	2,479
NGL—Bbld			
United States	351	365	426
Canada	1	4	—
Total	352	369	426
Total sales—Mcfed			
United States	97,120	102,073	104,858
Canada	23,802	8,042	2,563
Total	120,922	110,115	107,421

	Years Ended December 31,		
	2004	2003	2002
Natural gas, oil and NGL sales (in thousands)			
United States	$134,268	$127,339	$110,263
Canada	42,905	11,698	2,033
Total natural gas, oil and NGL sales	$177,173	$139,037	$112,296
Product sale revenues (in thousands)			
Natural gas sales	$150,716	$116,563	$ 90,289
Crude oil sales	22,782	19,576	19,679
NGL sales	3,675	2,898	2,328
Total oil, gas and NGL sales	$177,173	$139,037	$112,296
Unit prices—including impact of hedges			
Natural gas—per Mcf			
United States	$ 3.52	$ 3.32	$ 2.77
Canada	4.92	3.98	2.13
Consolidated	3.83	3.38	2.75
Crude oil—per Bbl			
United States	$ 33.07	$ 24.23	$ 21.74
Canada	—	24.46	—
Consolidated	33.07	24.23	21.74
NGL—per Bbl			
United States	$ 28.55	$ 21.45	$ 14.97
Canada	22.18	26.01	—
Consolidated	28.52	21.50	14.97

Our natural gas sales for 2004 were $150.7 million and increased $34.1 million from 2003 natural gas sales of $116.6 million. Our realized gas prices in the U.S. and Canada increased 6% and 24%, respectively. Increased prices contributed $23.8 million of the increase in 2004 sales. Natural gas sales volumes showed a net increase of 4,815,000 Mcf for 2004. Canadian 2004 sales volumes were nearly 5,760,000 Mcf over 2003 production of 2,935,000 Mcf; an increase of almost 200%. U.S. sales volumes were increased by production from new wells drilled in the New Albany Shale in Indiana and Kentucky, 1,380,000 Mcf; the Michigan Antrim Shale, 975,000 Mcf; the Michigan Prairie du Chien formation, 185,000 Mcf; and our initial production from the Barnett Shale in north Texas, 130,000 Mcf. Declining production rates on existing wells was the primary factor in production decreases that partially offset the production from new wells.

Our 2004 revenue from crude oil was $22.8 million and $3.2 million higher than 2003 crude oil revenue of $19.6 million. A 36% increase in realized crude oil prices from $24.23 to $33.07 per barrel boosted revenue $7.1 million. Lower volumes partially offset the increase due to prices by $3.9 million. The sale of Wyoming crude oil properties to Meritage Energy Partners LLC in the third quarter of 2004 lowered volumes by approximately 53,200 barrels. The remainder of the decrease was primarily due to natural declines from existing wells.

Sales of NGLs increased $0.8 million for 2004 to $3.7 million. The additional revenue was primarily the result of a 33% increase in realized NGL prices to $28.52 per barrel for 2004. A decrease in NGL volumes of approximately 6,000 barrels partially offset the increase from higher prices. Property dispositions in the third quarter of 2004 caused approximately 1,100 barrels of the volume decrease.

Natural gas sales for 2003 increased $26.3 million from 2002 to $116.6 million. Our average realized natural gas price increased 23% to $3.38 per Mcf for 2003 and increased sales $20.6 million. Volumes increased 1,690,000 Mcf from 2002 to 2003 and increased sales $5.7 million. Sales volumes for 2003 increased approximately 5,856,000 Mcf as a result of our drilling programs in the U.S. and Canada. Sales volumes from our Canadian CBM projects, which started production in January 2003, were approximately 2,113,000 Mcf for 2003. U.S. sales volumes increased 2,434,000 Mcf as a result of the additional interests in Michigan properties purchased from Enogex in December 2002. New wells drilled in the Michigan Antrim and Indiana New Albany formations increased sales volumes 1,071,000 Mcf and 239,000 Mcf, respectively. These increases were offset by curtailments in sales volumes as a result of extremely cold weather in the first quarter of 2003 and shutdowns of third party processing plants and pipelines in the second through fourth quarters of 2003. These events reduced sales volumes by approximately 260,000 Mcf and 814,000 Mcf, respectively. Additionally, March through September 2003 sales from our Indiana properties were curtailed when our local end-user reduced its deliveries of gas by approximately 161,000 Mcf. The remaining decreases were the result of natural decline in production from our existing natural gas wells.

Crude oil sales were $19.6 million for 2003 compared to $19.7 million in 2002. The $2.49 per barrel increase in our average realized crude oil price increased sales $2.3 million, which was nearly offset by the decrease in oil sales volumes for 2003. The 11% decrease in sales volumes to 808,000 barrels for the year was the result, in part, of a decrease of approximately 20,300 barrels due to the sale of Wyoming and Texas oil properties in June 2002. Natural production declines on existing wells contributed most of the remaining decreases. These reductions were partially offset by a full year's production from wells drilled in the Beaver Creek Detroit River Zone 3 development that increased sales volumes 31,800 barrels.

NGL sales for 2003 increased $0.6 million to $2.9 million. NGL prices increased $6.53 from 2002 to $21.50 and resulted in a $1.0 million increase in sales that was partially offset by a decrease in sales volumes.

Other Revenues

Other revenue, consisting primarily of revenue from the marketing, transportation and processing of natural gas, was $2.6 million for 2004 and about $0.6 million higher than other revenue for 2003. Other revenue in 2003 was reduced by $0.5 million as a result of the repurchase of Section 29 tax credit properties.

Other revenue of $1.9 million in 2003 consisted of revenue from the marketing, transportation and processing of natural gas. In 2002, other revenue also included revenue of $5.1 million from the sale of Section 29 tax credits. The tax credits expired in 2002. In 2003, a $0.5 million reduction in other revenue was the result of the repurchase of the tax credit properties. Natural gas marketing, transportation and processing revenue for 2003 was $2.5 million as compared to $4.6 million in 2002. Marketing revenue in 2003 decreased $1.8 million from 2002 primarily as a result of pipeline delivery imbalances that occurred during 2003. Repayments of those imbalances required the purchase of natural gas when natural gas prices had increased from the time in which the imbalances occurred resulting in marketing margin losses.

Operating Expenses

Our operating expenses for 2004 were $120.2 million and $26.4 million higher than operating expenses for 2003. Increases were primarily the result of higher sales volumes and producing well counts in Canada and Indiana, higher depletion rates and added depreciation on facilities and pipelines placed into service since mid-2003, and an increase in U.S. compressor overhauls performed in 2004 as compared to 2003. General and administrative costs also increased by $4.8 million in 2004.

Operating expenses were $93.8 million in 2003 compared to $81.5 million for 2002. The increase was primarily the result of additional sales volumes.

Oil and Gas Production Costs

	Years Ended December 31,		
	2004	2003	2002
	(in thousands, except per unit amounts)		
Production expenses			
United States	$54,783	$48,243	$40,505
Canada	10,403	3,951	1,723
	$65,186	$52,194	$42,228
Production expenses—per Mcfe			
United States	$ 1.54	$ 1.29	$ 1.06
Canada	1.19	1.35	1.84
Consolidated	1.47	1.30	1.08

Costs for the production of oil and gas were $65.2 million and $13.0 million higher in 2004 as compared to 2003. Higher oil and gas prices, as well as higher Canadian sales volumes for 2004, increased production tax expense $1.5 million. U.S. production expense increased $6.0 million in 2004, excluding production tax increases of $0.6 million. Initial operating expenses associated with new Indiana and Kentucky wells and production increased production expense approximately $2.2 million. The increase included approximately $0.9 million for salt-water disposal and equipment rentals. These expenses were the result of inadequate salt-water disposal capacity and delays in completing electricity connections at each well. During 2004, 35 new wells and 22 non-producing wells acquired in 2003 began production, in addition to 47 wells that began production in the fourth quarter of 2003. Operating costs began to decrease as initial production containing high concentrations of water was followed by natural gas production increases. Production overhead in Indiana increased approximately $0.8 million as a result of personnel added to operate and maintain these properties. Michigan and Indiana operating expenses increased approximately $1.5 million and $0.2 million, respectively, as a result of the routine periodic overhaul of several compressors. Similar overhaul expenses were not incurred during 2003. These items increased U.S. production expenses by $0.14 per Mcfe for 2004 compared to 2003. Remaining production expense increases were attributable to modest price increases across a broad range of expense categories.

Canadian production expenses in 2004, excluding a production tax increase of $0.9 million, increased $5.5 million for 2004. A net increase in Canadian production of approximately 5,780,000 Mcf and higher well counts were the primary factors for the increase. Total Canadian production expense, including production taxes, continued to reflect improving economies of scale as expense decreased on a Mcfe-basis to $1.19 per Mcfe.

Oil and gas production expense for 2003 was $52.2 million, compared to 2002 expense of $42.2 million. Production taxes were $3.0 million higher as a result of higher sales volumes and higher average natural gas and crude oil prices in 2003. Production expenses for U.S. properties in 2003 increased $5.0 million, excluding production tax increases of $2.7 million. Notable production expense increases included $3.1 million of additional expense associated with natural gas volumes produced from the acquired Enogex interests and $0.8 million resulting from settlement costs for post-production cost allowances in Michigan and environmental issues in Indiana and Michigan. Inventory losses, primarily in Indiana, increased expense $0.3 million in 2003. Additional operating expenses of approximately $0.8 million were primarily due to the start-up of producing wells in Indiana during the fourth quarter.

Canadian production expenses in 2003, excluding production taxes of $0.3 million, increased $1.9 million. Canadian production increased approximately 2,000,000 Mcf, primarily as a result of the start-up of production from our CBM projects in January 2003. Although absolute Canadian production expense increased, expense per Mcfe, including production taxes, decreased $0.49 to $1.35 per Mcfe for 2003 as a result of 2003 CBM production.

Depletion, Depreciation and Accretion

	Years Ended December 31,		
	2004	2003	2002
	(in thousands, except per unit amounts)		
Depletion	$34,530	$27,379	$26,953
Depreciation of other fixed assets	5,179	3,949	3,206
Accretion	982	739	—
Total depletion, depreciation and accretion	$40,691	$32,067	$30,159
Average depletion cost per Mcfe	$ 0.78	$ 0.68	$ 0.69

Depletion expense for 2004 was $34.5 million, as compared to 2003 depletion expense of $27.4 million. Additional sales volumes of approximately 4,070,000 Mcfe and a $0.10 per Mcfe increase in the consolidated depletion rate added $7.2 million of depletion expense from 2003 to 2004. The $0.10 per Mcfe higher consolidated depletion rate was the result of additional increases in future development costs as compared to increases in proved reserves when comparing engineering estimates of proved reserves for December 31, 2004 and 2003. The $1.2 million increase in 2004 depreciation was primarily the result of the addition of compression and transportation assets and overhead assets.

Depletion expense increased $0.4 million to $27.4 million in 2003. Increased depletion expense was the result of higher sales volumes partially offset by a slight decrease in our consolidated depletion rate. Additional depreciation of $0.7 million was primarily the result of additions to processing and transportation assets including the Cardinal Pipeline, which began operations in September 2003. Accretion expense of $0.7 million in 2003 was the result of the adoption of SFAS No. 143 as of January 1, 2003.

General and Administrative Expenses

General and administrative expenses were $12.9 million for 2004. Of the $4.8 million increase from 2003, additional expenses of $2.3 million were primarily the result of an increase in management and administrative personnel from August 2003 through March 2004. Contract labor, legal and accounting fees increased approximately $1.0 million for 2004 due largely to new Sarbanes-Oxley and corporate governance requirements. Engineering and other professional fees increased approximately $0.4 million from 2003 due primarily to additional fees for preparation of required outside engineering reserve reports. Various other expenses including outside directors' fees, charitable donations, insurance, investor relations and stock exchange fees increased a total of $0.6 million from 2003 expense amounts.

General and administrative expenses were $8.1 million for 2003 and $0.6 million higher than 2002 general and administrative expenses. The increase is primarily the result of $0.7 million in additional bonuses earned in 2003 and $0.3 million due to the addition of management personnel in the last half of the year. Professional fees were $0.2 million higher than in 2002 and were related to the use of additional engineering and accounting services. These increases were partially offset by the $0.3 million reduction in expense for contract labor in 2003.

Income from Equity Affiliates

Income from equity affiliates for 2003 increased $1.1 million from the prior year when we recorded losses of $0.8 million associated with Voyager Compression Services LLC. During 2002, Voyager recorded operating losses in addition to an impairment of its assets and lease termination costs in conjunction with ending its operations.

Interest Expense

Interest expense for 2004 was $15.7 million and $4.5 million less than 2003 interest expense. Interest expense in 2003 included a charge of $3.8 million as a result of the early redemption of $53.0 million in principal amount of our subordinated notes payable, which included a $3.2 million prepayment penalty and the write-off of $1.5 million of remaining deferred financing costs, partially offset by a deferred hedging gain of $0.9 million. Ongoing interest expense decreased approximately $0.7 million due to a decrease in LIBOR interest rates and the 2003 issuance of our second mortgage notes, which accrue interest at a substantially lower rate than the subordinated notes payable that were retired in mid-2003, partially offset by an increase in our average debt outstanding during 2004 as compared to 2003.

Interest expense was $20.2 million in 2003. Interest expense for 2003 included a charge of $3.8 million as a result of the early redemption of $53.0 million in principal amount of our subordinated notes payable through the issuance of $70.0 million in principal amount of second mortgage notes. The $3.8 million charge consisted of a prepayment premium of $3.2 million and the write-off of $1.5 million of remaining deferred financing costs, partially offset by an associated deferred hedging gain of $0.9 million. Ongoing interest expense decreased $2.8 million as a result of a significant decrease in our effective interest rates that was partially offset by an increase in our average debt outstanding in 2003. The interest rates paid on our debt were lower in 2003 because of lower LIBOR rates and the refinancing of our subordinated notes payable through the issuance of our second mortgage notes.

Income Taxes

	Years Ended December 31,		
	2004	2003	2002
Income tax provision (in thousands)	$14,174	$9,997	$7,498
Effective tax rate	31.2%	35.1%	35.2%

Our income tax provision for 2004 was $14.2 million. Our U.S. income tax provision was established using the statutory U.S. federal tax rate of 35.0%. In addition to the deferred tax provision of approximately $8.8 million, a current U.S. tax provision of $0.8 million was accrued for U.S. federal income tax due on a dividend distribution of approximately $86.5 million made to us by MGV in 2004 and consisted of estimated earnings and profits of $15.5 million. We have planned for reinvestment of the dividend in the U.S. under a qualified domestic reinvestment plan as defined under recently enacted Internal Revenue Code Section 965(a)(1), which allows 85% of the dividend to be excluded from U.S. taxable income for the year. The Canadian income tax provision consisted of a deferred tax provision of approximately $5.9 million accrued at a Canadian combined federal and provincial statutory rate of 33.6% and a current tax provision of $0.3 million. The deferred tax provision was reduced by a scientific, research and experimental development tax credit of $1.7 million. This credit was granted by Revenue Canada to MGV in 2004 for expenditures incurred in 2001.

Our income tax provision of $10.0 million for 2003 was established using an effective U.S. federal tax rate of 35%. The provision also includes $1.7 million for Canadian federal and provincial income tax expense. Canadian income tax expense includes consideration of tax rate reductions that were enacted during 2003. Income tax expenses increased from the prior year as a result of higher 2003 pretax income as compared to 2002.

LIQUIDITY, CAPITAL RESOURCES AND FINANCIAL POSITION

Our statements of cash flows are summarized as follows:

	Year ended December 31,		
	2004	2003	2002
		(in thousands)	
Net cash flow provided by operating activities	$99,449	$59,280	$44,198

Cash flows from operating activities increased $40.2 million, or 68%, for 2004 compared to 2003. The principal factor in the increase was a $12.2 million increase in operating income for 2004, together with increases in accounts receivable and payable, accrued liabilities and depletion, depreciation and amortization. In addition, 2003 income included a $3.2 million prepayment premium incurred when the $53 million of subordinated notes were redeemed. Operating cash flows were also higher because of MGV's use of cash calls on other working interest owners prior to incurring capital expenditures on various CBM exploration and development projects. A reduction in QRI's third party marketing activities further increased operating cash flows about $2.0 million.

Cash flows from operating activities were $15.1 million, or 34%, higher for 2003 compared to 2002. A 19% increase in operating income for 2003 as compared to 2002 was the principal factor. The $7.8 million increase in operating income was largely due to a 21% increase in realized average prices and a 3% increase in sales volumes. Operating income for 2002 included $5.1 million of deferred revenue that was offset by additional oil, gas and NGL revenue for 2003, which effectively increased operating cash flows by $5.1 million for 2003.

Our principal operating sources of cash include sales of natural gas, crude oil and NGLs and revenues from natural gas transportation and processing. We sold approximately 74% and 85% of our 2004 and 2003 natural gas and crude oil production, respectively, under long-term contracts with price floors and financial hedges. As a result, we benefit from significant predictability of our natural gas and crude oil revenues. However, when natural gas and crude oil market prices exceed our financial hedge swap prices, we are required 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 payment from our customers until 25 to 60 days after the month of production. Additionally, in the event of a significant production curtailment, we are required contractually to fulfill our commitments under our long-term sales contracts by purchasing natural gas volumes at market prices.

	Year ended December 31,		
	2004	2003	2002
		(in thousands)	
Cash flow (used in) provided by investing activities:			
Purchase/acquisition of properties and equipment	$(231,757)	$(149,172)	$(88,965)
Distributions and advances from equity affiliates—net	2,097	1,649	4,043
Proceeds from sale of properties and equipment	9,160	101	1,263
Net cash used in investing activities:	$(220,500)	$(147,422)	$(83,659)

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, 2004. We currently estimate that our spending for property, plant and equipment in 2005 will be as much as $261 million. Total capital expenditures by operating segment for 2004, 2003 and 2002 are as follows:

Capital expenditures

	United States	Canada	Consolidated
		(in thousands)	
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, transportation and administrative	12,527	769	13,296
Total	$127,177	$104,580	$231,757
2003			
Proved acreage	$ 3,215	$ 3,388	$ 6,603
Unproved acreage	24,063	6,739	30,802
Development costs	37,682	41,820	79,502
Exploration costs	9,411	17,066	26,477
Gas processing, transportation and administrative	4,820	284	5,104
Total	$ 79,191	$ 69,297	$148,488
2002			
Proved acreage	$ 32,199	$ —	$ 32,199
Unproved acreage	550	5,422	5,972
Development costs	34,178	938	35,116
Exploration costs	5,925	8,659	14,584
Gas processing, transportation and administrative	952	142	1,094
Total	$ 73,804	$ 15,161	$ 88,965

Our 2004 capital expenditures for exploration and development activities were focused in four areas. Expenditures for Canadian exploration and development 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 exploration and development 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 transportation 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.

Capital expenditures in 2003 of $148.5 million included $69.0 million for development and exploration of our Canadian CBM projects and acreage. We spent $31.8 million for further development of our Indiana/ Kentucky properties and additional acreage positions. Our pipeline in the area, Cardinal Pipeline, accounted for $4.0 million of our capital expenditures. Michigan capital expenditures of $24.6 million focused on continued development and exploitation of the Antrim Shale. A significant acreage position in north Texas was acquired for approximately $12.6 million in 2003.

We acquired Michigan natural gas interests from Enogex Exploration Corporation in December 2002 for approximately $32.0 million. Canadian capital expenditures were $15.0 million associated with CBM exploration costs and acreage acquisition. The remaining $42.0 million was spent on exploration and development costs incurred primarily in Michigan and Indiana.

	Year ended December 31,		
	2004	2003	2002
		(in thousands)	
Cash flow provided by financing activities:			
Issuance of debt	$ 511,091	$ 114,000	$ 16,000
Repayment of debt	(371,178)	(113,116)	(14,912)
Issuance of common stock, net of issuance costs	2,499	79,926	40,640
Purchase of treasury stock	—	—	(316)
Debt issuance costs	(8,023)	(1,441)	(1,362)
Net cash provided by investing activities:	$ 134,389	$ 79,369	$ 40,050

During 2004, we extended and increased our senior secured credit facility. Currently, our credit facility is a revolving facility that matures on July 28, 2009 and permits us to obtain revolving credit 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. The current borrowing base is $300 million and is subject to annual redetermination and certain other redeterminations based upon several factors. Scheduled redeterminations occur on May 1 of each year. Our borrowing base is impacted primarily by the fair value of our oil and gas reserves. Changes in the fair value of our oil and gas reserves are affected by prices for natural gas and crude oil, operating expenses and the results of our drilling activity. A significant decline in the fair value of our reserves could reduce our borrowing base. A borrowing base reduction could limit our ability to carry out our capital expenditure programs and, in some circumstances, require the repayment of a portion of our outstanding borrowings under the facility.

At our option, loans may be prepaid, and revolving credit commitments may be reduced, in whole or in part at any time in minimum amounts. As of year-end, we can designate the interest rate on amounts outstanding at either the London Interbank Offered Rate (LIBOR) +1.375% or specified bank rates. The collateral for the credit facility consists of substantially all of our existing assets and any future reserves acquired. The loan agreements prohibit the declaration or payment of dividends by us and contain other restrictive covenants, which, among other things, require the maintenance of a minimum current ratio (calculated in accordance with provisions of the loan agreements) of at least 1.0. At December 31, 2004, we were in compliance with all such restrictions and we had $119.1 million available under the credit facility.

On November 1, 2004, we sold $150 million of 1.875% convertible subordinated debentures due in 2024 for gross proceeds of approximately $147.8 million. Holders of the debentures may require us 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 21.8139 shares for each $1,000 debenture, subject to adjustment. This results in an initial conversion price of approximately $45.84 per share and represents a premium of 42.5 percent over the closing sale price of $32.17 per share on October 26, 2004. Generally, except upon the occurrence of specified events, holders of the debentures are not entitled to exercise their conversion rights until the Company's stock price is $55.01 (120 % of the conversion price per share). Upon conversion, we have the option to deliver in lieu of Quicksilver common stock, cash or a combination of cash and Quicksilver common stock.

On December 31, 2004, we had outstanding $70 million of Second Mortgage Notes due 2006, of which $40 million bore interest at a fixed rate of 7.5% and $30 million bore interest at a variable rate based upon three-month LIBOR plus 5.48%. The Second Mortgage Notes contain restrictive covenants that, among other things, require maintenance of a minimum current ratio of at least 1.0, a ratio of net present value of proved reserves to total debt of at least 1.8 to 1.0; and a ratio of earnings before interest, taxes, depreciation and amortization and non-cash income and expense to interest expense of at least 1.25 (calculated in each case in accordance with provisions of the Second Mortgage Notes). At December 31, 2004, we were in compliance with such restrictions.

As of December 31, 2004, 2003 and 2002, our total capitalization was as follows:

	Year ended December 31,		
	2004	2003	2002
		(in thousands)	
Long-term and short-term debt:			
Senior secured credit facility	$180,422	$178,000	$192,000
Convertible subordinated debentures	147,769	—	—
Second mortgage notes payable	70,000	70,000	—
Subordinated notes payable	—	—	53,000
Mercury note payable	—	—	1,920
Various loans	1,073	1,386	1,582
Deferred gain – fair value interest hedge	226	—	—
Fair value interest hedge	—	50	942
Total debt	399,490	249,436	249,444
Stockholders' equity	304,276	241,816	128,905
Total capitalization	$703,766	$491,252	$378,349

We believe that our capital resources are adequate to meet the requirements of our existing business. We anticipate that our 2005 capital expenditure budget of approximately $261 million will be funded by cash flow from operations, credit facility utilization and the possible issuance of debt or equity securities.

Financial Position

The following impacted our balance sheet as of December 31, 2004, as compared to our balance sheet as of December 31, 2003:

- A $150.0 million increase in our debt used to finance the exploration and development of our oil and gas properties in 2004.
- A $198.0 million increase in our net property, plant and equipment balances resulting from capital expenditures for exploration and development of our oil and gas properties.
- A $21.8 million and $9.7 million decrease in our current and deferred derivative obligations, respectively, reflecting the four-month remaining term on our $2.79 per Mcf natural gas swaps as of December 31, 2004.

Contractual Obligations and Commercial Commitments

Information regarding our contractual obligations (within the scope of Item 303(a)(5) of Regulations S-K) as of December 31, 2004 is set forth in the following table. At December 31, 2004, we did not have any capital lease obligations or material purchase obligations that were binding on us and that specified all significant terms. Other long-term liabilities constituting contractual obligations reflected on our balance sheet at December 31, 2004 consisted of derivative obligations and asset retirement obligations.

	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	$401,495	$ 356	$70,718	$180,421	$150,000
Derivative Obligations	13,090	13,090	—	—	—
Asset Retirement Obligations	18,471	504	168	112	17,687
Gas Purchase Obligations	1,803	1,803	—	—	—
Operating Lease Obligations	6,894	2,160	4,059	675	
Total Obligations	$441,753	$17,913	$74,945	$181,208	$167,687

- Long-Term Debt—As of December 31, 2004, we had $180.4 million outstanding under our credit facility, $150.0 million of contingently convertible debentures (before discount), $70 million of second mortgage notes and $1.1 million of other debt. Based upon our debt outstanding at December 31, 2004, we anticipate interest payments to be approximately $15.7 million in 2005. We expect to increase borrowings under our credit facility to fund our capital program throughout 2005. For each additional $10 million in borrowings, annual interest payments will increase by approximately $0.4 million. If our borrowing base were to be fully utilized by year-end 2005, we estimate that interest payments would increase by approximately $4.0 million. If interest rates on our variable interest-rate debt of $112.8 million, as of February 28, 2005, and $75 million of variable rate debt hedged through March 31, 2005 increase or decrease by one percentage point, our annual pretax income will decrease or increase by $1.7 million. Interest payments would increase by a further $2.8 million annually should we utilize all of the $119.1 million available under our senior credit facility at December 31, 2004.

- Derivative Obligations—We utilize financial derivatives to manage price risk associated with our natural gas and crude oil product revenue. We also manage interest rate risk associated with our long-term debt. The recorded assets and liabilities associated with our derivative obligations were estimated based on published market prices of natural gas and crude oil for the periods covered by the contracts. Estimates of the liability associated with our interest rate derivative obligations are based upon estimates prepared by our counterparties. These amounts do not necessarily reflect what payments will be made to settle these obligations.

- Asset Retirement Obligations—Our liabilities include the fair value, $18.5 million, of asset retirement obligations that result from the acquisition, construction or development and the normal operation of our long-lived assets.

- Gas Purchase Obligations—Cinnabar, our subsidiary that ceased operations January 1, 2004, previously contracted to purchase gas through May 2005 for resale to the open market. Quicksilver has assumed the obligation.

- Operating Leases—We lease office buildings and other property under operating leases. $3.6 million of our operating lease obligations are with an affiliate of Mercury, which is owned by members of the Darden family.

We have the following commercial commitments as of December 31, 2004.

	Amounts of Commitments Expiration per Period				
	Total Committed	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
	(in thousands)				
Commercial Commitments					
Standby Letters of Credit	$637	$637	$—	$—	$—
Total Commitments	$637	$637	$—	$—	$—

Standby Letters Of Credit—Our letters of credit have been issued to fulfill contractual or regulatory requirements. The majority 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," "will," "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;
- 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;
- 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

In December 2004, the Financial Accounting Standards Boards ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 123(R), *Share-Based Payment*, which establishes accounting standards for all transactions in which an entity exchanges its equity instruments for goods and services. SFAS No. 123(R) focuses primarily on accounting for transactions with employees, and carries forward without change prior guidance for shared-based payments for transactions with non-employees.

SFAS No. 123(R) eliminates the intrinsic value measurement objective in Accounting Principle Board ("APB") Opinion 25 and generally requires measurement of the cost of employee services received in exchange for an award of equity instruments be based on the fair value of the award on the date of the grant. The standard requires grant date fair value to be estimated using either an option-pricing model that is consistent with the terms of the award or a market observed price, if such a price exists. Such cost must be recognized over the period during which an employee is required to provide service in exchange for the award (which is usually the vesting period). The standard also requires estimation of the number of instruments that will ultimately be issued rather than accounting for forfeitures as they occur.

We are required to apply SFAS No. 123(R) to all awards granted, modified or settled in our first reporting period under U.S. GAAP after June 15, 2005. The standard requires use of either the "modified prospective method" or the "modified retrospective method." Under the modified prospective method, compensation cost is recognized for all awards granted after adoption of the standard and for the unvested portion of previous grant awards that are outstanding on that date. The modified retrospective method is used to recognize compensation cost for prior periods whereby previously issued financial statements are restated to recognize the amounts we previously calculated and reported on a pro forma basis. Under both methods, the standard permits the use of either a straight-line or an accelerated method to amortize the cost as an expense for awards that vest over time. The standard permits and encourages early adoption.

Management has commenced analysis of the impact of SFAS No. 123(R), but has not yet decided: (1) whether to elect early adoption, (2) if early adoption is elected, at what date to adopt the standard, (3) whether to use the modified prospective method or elect to use the modified retrospective method, and (4) whether to use straight-line amortization or an accelerated method. Additionally we cannot predict with reasonable certainty the number of options that will be unvested and outstanding on December 31, 2005. Accordingly, management cannot currently quantify with precision the effect this standard would have on the Company's financial position or results of operations in the future, except that a greater expense will probably be recognized for any awards that we may grant in the future.

In November 2004, the FASB issued SFAS No. 151, *Inventory Costs, an amendment of ARB No. 43, Chapter 4*, which amends Chapter 4 of ARB No. 43 that deals with inventory pricing. The statement clarifies the accounting for abnormal amounts of idle facility expenses, freight, handling costs and spoilage. Under paragraph 5 of ARB No. 43, such items might be considered to be so abnormal, under certain circumstances, as to require treatment as current period charges. SFAS No. 151 eliminates the criterion of "so abnormal" and requires that those items be recognized as current period charges. The statement also requires allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. This statement is effective for inventory costs incurred during fiscal years beginning after June 15, 2005, although earlier application is permitted for fiscal years beginning after the issuance date of the statement. Retroactive application is not permitted. Management is analyzing the requirements of SFAS No. 151 and believes that its adoption will not have any significant impact on the financial position, results of operations or cash flows of the Company.

The FASB issued SFAS No. 153, *Exchanges of Nonmonetary Assets, an amendment of APB No. 29* in December 2004. The statement amends Opinion 29 by eliminating the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. SFAS No. 153 provides that a nonmonetary exchange has commercial substance if future cash flows of the entity are expected to change significantly as a result of the exchange. The statement is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. Earlier application is permitted for nonmonetary asset exchanges occurring in fiscal periods beginning after the date of the issuance of the statement. Retroactive application is not permitted. Management is analyzing the requirements of SFAS No. 151 and believes that its adoption will not have any significant impact on the financial position, results of operations or cash flows of the Company.

FASB Staff Position ("FSP") No. 109-2, *Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004*, was issued in December 2004. This FSP provides guidance on accounting for special reductions in taxes included in the American Jobs Creation Act of 2004. In particular, the Act allows a one-time decrease in U.S. Federal taxes on repatriated foreign earnings. FSP No. 109-2 clarifies that a company's consideration of the Act does not overrule their prior contention that the foreign earnings were permanently reinvested. Also, this FSP indicates that companies should provide tax expense when a decision is made to repatriate some or all foreign earnings, and provide disclosure about the possible range of repatriation if the analysis is not yet complete. We repatriated $86.5 million through a Canadian dividend distribution in 2004 and provided approximately $0.8 million of current income tax expense in 2004.

In September 2004, the SEC issued Staff Accounting Bulletin ("SAB") No. 106. This pronouncement requires companies that use the full cost method of accounting for oil and gas producing activities to include an estimate of future asset retirement costs to be incurred as a result of future development activities on proved reserves in their calculation of depreciation, depletion and amortization. It also requires full cost companies to exclude any cash outflows associated with settling asset retirement obligations from their full cost ceiling test calculation. In addition, it requires specific disclosures regarding the impact of asset retirement obligations on oil and gas producing activities, ceiling test calculations and depreciation, depletion and amortization calculations. We will adopt the provisions of this pronouncement in the first quarter of 2005. We believe the adoption of SAB No. 106 will have no immediate effect on our consolidated financial statements.

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, 2004 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, 2004, 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

President and Chief Executive Officer

/s/ Bill Lamkin

Executive Vice President and Chief Financial Officer

Fort Worth, Texas
March 16, 2005

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, 2004 and 2003 and the related consolidated statements of income, comprehensive income, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2004. 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 statements 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 Company as of December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to the consolidated financial statements, on January 1, 2003, the Company adopted Statement of Financial Accounting Standard No. 143, *Accounting for Asset Retirement Obligations.*

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, 2004, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 16, 2005 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Fort Worth, Texas
March 16, 2005

QUICKSILVER RESOURCES INC.
CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2004 AND 2003
In thousands, except for share data

	2004	2003(1)
ASSETS		
Current assets		
Cash and cash equivalents	$ 15,947	$ 4,116
Accounts receivable	38,037	26,247
Current deferred income taxes	3,523	11,760
Inventories and other current assets	8,689	7,588
Total current assets	66,196	49,711
Investments in and advances to equity affiliates	8,254	9,173
Property, plant and equipment		
Oil and gas properties, full-cost method		
Subject to depletion	838,134	665,457
Unevaluated costs	97,168	49,919
Pipelines and processing facilities	70,851	56,980
General properties	12,597	7,645
Accumulated depletion and depreciation	(216,140)	(175,425)
Property, plant and equipment – net	802,610	604,576
Other assets	11,274	3,474
	$ 888,334	$ 666,934
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of long-term debt	$ 356	$ 339
Accounts payable	28,407	17,954
Accrued derivative obligations	12,784	34,577
Accrued liabilities	41,904	27,644
Total current liabilities	83,451	80,514
Long-term debt	399,134	249,097
Deferred derivative obligations	—	9,662
Asset retirement obligations	17,967	15,135
Deferred income taxes	83,506	70,710
Commitments and contingencies (Note 13)	—	—
Stockholders' equity		
Preferred stock, $0.01 par value, 10,000,000 shares authorized, 1 share issued as of December 31, 2004 and 2003	—	—
Common stock, $0.01 par value, 100,000,000 and 80,000,000 shares authorized, and 52,690,971 and 52,045,726 shares issued as of December 31, 2004 and 2003, respectively	527	520
Paid in capital in excess of par value	200,941	194,246
Treasury stock of 2,568,611 and 2,578,904 shares as of December 31, 2004 and 2003, respectively	(10,258)	(10,299)
Accumulated other comprehensive income (loss)	6,762	(17,683)
Retained earnings	106,304	75,032
Total stockholders' equity	304,276	241,816
	$ 888,334	$ 666,934

(1) Share and per share amounts have been adjusted to reflect a two-for-one stock split effected in the form of a stock dividend in June 2004. The split did not affect treasury shares.

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, 2004, 2003 AND 2002
In thousands, except for per share data

	2004	2003(1)	2002(1)
Revenues			
Oil, gas and NGL sales	$177,173	$139,037	$112,296
Other revenue	2,556	1,912	9,683
Total revenues	179,729	140,949	121,979
Expenses			
Oil and gas production costs	65,186	52,194	42,228
Other operating costs	1,250	1,301	1,538
Depletion, depreciation and amortization	40,691	32,067	30,159
Provision for doubtful accounts	153	87	—
General and administrative	12,934	8,133	7,552
Total expenses	120,214	93,782	81,477
Income from equity affiliates	1,178	1,331	200
Operating income	60,693	48,498	40,702
Other income-net	(415)	(186)	(470)
Interest expense	15,662	20,182	19,839
Income before income taxes	45,446	28,502	21,333
Income tax expense	14,174	9,997	7,498
Income before cumulative effect of change in accounting principle	31,272	18,505	13,835
Cumulative effect of change in accounting principle, net of tax	—	2,297	—
Net income	$ 31,272	$ 16,208	$ 13,835
Other comprehensive income (loss)—net of taxes			
Net derivative settlements	26,875	27,037	7,114
Net change in derivative fair value	(5,174)	(20,939)	(27,237)
Foreign currency translation adjustment	2,744	10,389	(40)
Comprehensive income (loss)	$ 55,717	$ 32,695	$ (6,328)
Basic net income per common share:			
Income before cumulative effect of change in accounting principle	$ 0.63	$ 0.41	$ 0.35
Cumulative effect of change in accounting principle, net of tax	—	(0.05)	—
Net income	$ 0.63	$ 0.36	$ 0.35
Diluted net income per common share:			
Income before cumulative effect of change in accounting principle	$ 0.62	$ 0.41	$ 0.34
Cumulative effect of change in accounting principle, net of tax	—	(0.06)	—
Net income	$ 0.62	$ 0.35	$ 0.34
Basic weighted average shares outstanding	49,769	44,789	39,613
Diluted weighted average shares outstanding	51,343	45,689	40,789

(1) Share and per share amounts have been adjusted to reflect a two-for-one stock split effected in the form of a stock dividend in June 2004. The split did not affect treasury shares.

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, 2004, 2003 AND 2002
In thousands, except for share and per share data

	2004	2003(1)	2002(1)
Preferred stock, $0.01 par value, 10,000,000 shares authorized			
Balance at beginning of year	$ —	$ —	$ —
Issuance of 1 share special voting preferred	—	—	—
Balance at end of year: 1 share issued at December 31, 2004, 2003 and 2002	—	—	—
Common stock, $0.01 par value, 100,000,000 shares authorized			
Balance at beginning of year	520	448	413
Issuance of common stock	7	72	35
Balance at end of year: 52,690,971; 52,045,726 and 45,069,750 shares issued at December 31, 2004, 2003 and 2002, respectively	527	520	448
Paid in capital in excess of par value			
Balance at beginning of year	194,246	113,902	77,627
Acquisition of minority interest	—	—	(189)
Acquisition of Voyager Compression Services assets	—	(515)	—
Warrants exercised	—	—	16,355
Treasury stock reissued	148	—	19,459
Issuance of common stock	—	79,205	—
Stock options exercised	2,304	1,014	842
Tax benefit related to stock options exercised	4,243	739	—
Fair value of options issued	—	—	229
Stock issuance costs	—	(99)	(421)
Balance at end of year	200,941	194,246	113,902
Treasury stock, at cost			
Balance at beginning of year	(10,299)	(10,099)	(14,634)
(Acquisition) reissuance of treasury stock-net	41	(200)	4,535
Balance at end of year: 2,568,611; 2,578,904 and 2,570,502 shares at December 31, 2004, 2003, and 2002, respectively	(10,258)	(10,299)	(10,099)
Accumulated other comprehensive loss			
Deferred losses on hedge derivatives			
Balance at beginning of year	(27,359)	(33,457)	(13,334)
Net change during the year related to cash flow hedges	21,701	6,098	(20,123)
Balance at end of year	(5,658)	(27,359)	(33,457)
Deferred foreign exchange adjustment			
Balance at beginning of year	9,676	(713)	(673)
Foreign currency translation adjustment	2,744	10,389	(40)
Balance at end of year	12,420	9,676	(713)
Total accumulated other comprehensive income (loss)	6,762	(17,683)	(34,170)
Retained earnings			
Balance at beginning of year	75,032	58,824	44,989
Net income	31,272	16,208	13,835
Balance at end of year	106,304	75,032	58,824
Total stockholders' equity	$304,276	$241,816	$128,905

(1) Share and per share amounts have been adjusted to reflect a two-for-one stock split effected in the form of a stock dividend in June 2004. The split did not affect treasury shares.

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, 2004, 2003 AND 2002
In thousands

	2004	2003	2002
Operating activities:			
Net income	$ 31,272	$ 16,208	$ 13,835
Charges and credits to net income not affecting cash			
Cumulative effect of accounting change, net of tax	—	2,297	—
Depletion, depreciation and amortization	40,691	32,067	30,159
Deferred income taxes	12,989	9,736	7,760
Recognition of unearned revenues	—	507	(3,678)
Income from equity affiliates	(1,178)	(1,331)	(200)
Amortization of deferred loan costs	1,249	2,637	1,239
Non-cash (gain) loss from hedging activities	(786)	(678)	842
Other	91	455	169
Changes in assets and liabilities			
Accounts receivable	(11,562)	(5,259)	414
Inventory, prepaid expenses and other assets	2,364	(918)	(852)
Accounts payable	10,453	2,958	2,763
Accrued and other liabilities	13,866	601	(8,253)
Net cash provided by operating activities	99,449	59,280	44,198
Investing activities:			
Purchase of properties and equipment	(231,757)	(148,488)	(88,965)
Acquisition of Voyager Compression Service assets	—	(684)	—
Distributions and advances from equity affiliates-net	2,097	1,649	4,043
Proceeds from sale of properties	9,160	101	1,263
Net cash used for investing activities	(220,500)	(147,422)	(83,659)
Financing activities:			
Issuance of debt	511,091	114,000	16,000
Repayments of debt	(371,178)	(113,116)	(14,912)
Proceeds from issuance of common stock, net of issuance costs	—	79,176	39,725
Proceeds from exercise of stock options	2,499	750	915
Purchases of treasury stock	—	—	(316)
Debt issuance costs	(8,023)	(1,441)	(1,362)
Net cash provided by financing activities	134,389	79,369	40,050
Effect of exchange rates on cash	(1,507)	3,773	(199)
Net increase (decrease) in cash and equivalents	11,831	(5,000)	390
Cash and equivalents at beginning of period	4,116	9,116	8,726
Cash and equivalents at end of period	$ 15,947	$ 4,116	$ 9,116

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

QUICKSILVER RESOURCES INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002

1. NATURE OF OPERATIONS

Quicksilver Resources Inc. ("Quicksilver") is an independent oil and gas company incorporated in the state of Delaware and headquartered in Fort Worth, Texas. Quicksilver engages in the acquisition, development, exploration, production and sale of natural gas, crude oil and natural gas liquids as well as the marketing, processing and transmission of natural gas. Substantial portions of Quicksilver's reserves are located in Michigan, Indiana, Kentucky, Texas, 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, MGV Energy Inc. ("MGV") 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, quantity of natural gas in storage, foreign supply of crude oil and natural gas, the price of foreign imports, the level of consumer demand and the price of available alternative fuels. Quicksilver manages a portion of the operating risk relating to natural gas and crude oil price volatility through hedging and fixed price contracts.

2. SIGNIFICANT ACCOUNTING POLICIES

Stock Split

On June 1, 2004, Quicksilver announced that its Board of Directors declared a two-for-one stock split of Quicksilver's outstanding common stock effected in the form of a stock dividend. The stock dividend was payable on June 30, 2004, to holders of record at the close of business on June 15, 2004. The split did not affect treasury shares.

The capital accounts, all share data and earnings per share data included in the accompanying Consolidated Financial Statements for all years presented have been adjusted to retroactively reflect the stock split.

Principles of Consolidation

The Consolidated Financial Statements include the accounts of Quicksilver and its subsidiaries (collectively, the "Company"). 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 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 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 beginning on page 87), 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.

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 2004, two purchasers accounted for approximately 15% and 14%, respectively, of the Company's total consolidated natural gas and crude oil 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 Hedge 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 are recognized currently in earnings.

The Company's long-term contracts for delivery of 25,000 Mcfd and 10,000 Mcfd at a floor of $2.49 and $2.47, respectively, through March 2009 are not considered derivatives but rather normal sales contracts under SFAS No. 133. For 2004, approximately 5,300 Mcfd of these volumes were third-party volumes controlled by the Company.

Inventories

Inventories 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.

Properties, 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, 2004 and 2003, 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. MGV, 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 MGV 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 due to the short maturity of such instruments.

Foreign Currency Translation

The Company's Canadian subsidiary, MGV, 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.

	Years Ended December 31,		
	2004	2003	2002
	(in thousands, except per share data)		
Income before cumulative effect of change in accounting principle	$31,272	$18,505	$13,835
Cumulative effect of change in accounting principle	—	2,297	—
Net income	31,272	16,208	13,835
Impact of assumed conversions—interest on 1.875% contingently convertible debentures, net of income taxes	317	—	—
Income available to stockholders assuming conversion of contingently convertible debentures	$31,589	$16,208	$13,835
Weighted average common shares—basic	49,769	44,789	39,613
Effect of dilutive securities:			
Stock options	1,029	900	1,117
Warrants	—	—	59
Contingently convertible debentures	545	—	—
Weighted average common shares—diluted	51,343	45,689	40,789
Basic:			
Income before effect of change in accounting principle	$ 0.63	$ 0.41	$ 0.35
Cumulative effect of change in accounting principle	—	(0.05)	—
Net income	$ 0.63	$ 0.36	$ 0.35
Diluted:			
Income before effect of change in accounting principle	$ 0.62	$ 0.41	$ 0.34
Cumulative effect of change in accounting principle	—	(0.06)	—
Net income	$ 0.62	$ 0.35	$ 0.34

No outstanding options were excluded from the diluted net income per share calculation for either 2004 or 2003. Warrants representing 1,100,000 shares of common stock were excluded from the 2002 diluted net income per share computation for the period prior to their exercise as the exercise price exceeded the average market price of the Company's common stock.

Stock-Based Employee Compensation

At December 31, 2004, the Company has two stock-based compensation plans, which are described more fully in Note 16. The Company accounts for its plans under the recognition and measurement principles of APB No. 25, *Accounting for Stock Issued to Employees*, and related Interpretations. No stock-based employee compensation cost is reflected in net income, as all options granted under the plan had an exercise price equal to the market value of the underlying common stock on the date of grant. The following table illustrates the effect on net income and earnings per share if the Company had applied fair value recognition provisions of FASB Statement No. 123, *Accounting for Stock-Based Compensation.*

	Years Ended December 31,		
	2004	2003	2002
	(in thousands, except per share data)		
Net income, as reported	$31,272	$16,208	$13,835
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of income taxes	(3,169)	(436)	(674)
Pro forma net income	$28,103	$15,772	$13,161
Earnings per share			
Basic—as reported	$ 0.63	$ 0.36	$ 0.35
Basic—pro forma	$ 0.56	$ 0.35	$ 0.33
Diluted—as reported	$ 0.62	$ 0.35	$ 0.34
Diluted—pro forma	$ 0.55	$ 0.35	$ 0.32

Recently Issued Accounting Standards

In December 2004, the Financial Accounting Standards Boards ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 123(R), *Share-Based Payment*, which establishes accounting standards for all transactions in which an entity exchanges its equity instruments for goods and services. SFAS No. 123(R) focuses primarily on accounting for transactions with employees, and carries forward without change prior guidance for shared-based payments for transactions with non-employees.

SFAS No. 123(R) eliminates the intrinsic value measurement objective in Accounting Principle Board ("APB") Opinion 25 and generally requires measurement of the cost of employee services received in exchange for an award of equity instruments be based on the fair value of the award on the date of the grant. The standard requires grant date fair value to be estimated using either an option-pricing model which is consistent with the terms of the award or a market observed price, if such a price exists. Such cost must be recognized over the period during which an employee is required to provide service in exchange for the award (which is usually the vesting period). The standard also requires estimation of the number of instruments that will ultimately be issued rather than accounting for forfeitures as they occur.

SFAS No. 123(R) will apply to all awards granted, modified or settled in our first reporting period under U.S. GAAP after June 15, 2005. The standard requires use of either the "modified prospective method" or the "modified retrospective method." Under the modified prospective method, compensation cost is recognized for all awards granted after adoption of the standard and for the unvested portion of previous grant awards that are outstanding on that date. The modified retrospective method is used to recognize compensation cost for prior periods whereby previously issued financial statements are restated to recognize the amounts we previously calculated and reported on a pro forma basis. Under both methods, the standard permits the use of either a straight-line or an accelerated method to amortize the cost as an expense for awards that vest over time. The standard permits and encourages early adoption.

Management has commenced analysis of the impact of this statement, but has not yet decided: (1) whether to elect early adoption, (2) if early adoption is elected, at what date to adopt the standard, (3) whether to use the modified prospective method or elect to use the modified retrospective method, and (4) whether to use straight-line amortization or an accelerated method. Additionally management cannot predict with reasonable certainty the number of options that will be unvested and outstanding on December 31, 2005. Accordingly, the effect of this standard would have on the Company's financial position or results of operations in the future cannot be currently quantified with precision, except that a greater expense will probably be recognized for any awards granted in the future.

In November 2004, the FASB issued SFAS No. 151, *Inventory Costs, an amendment of ARB No. 43, Chapter 4*, which amends Chapter 4 of ARB No. 43 that deals with inventory pricing. The statement clarifies the accounting for abnormal amounts of idle facility expenses, freight, handling costs and spoilage. Under paragraph 5 of ARB No. 43, such items might be considered to be so abnormal, under certain circumstances, as to require treatment as current period charges. SFAS No. 151 eliminates the criterion of "so abnormal" and requires that those items be recognized as current period charges. The statement also requires allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. This statement is effective for inventory costs incurred during fiscal years beginning after June 15, 2005, although earlier application is permitted for fiscal years beginning after the issuance date of the statement. Retroactive application is not permitted. Management is analyzing the requirements of SFAS No. 151 and believes that its adoption will not have any significant impact on the financial position, results of operations or cash flows of the Company.

The FASB issued SFAS No. 153, *Exchanges of Nonmonetary Assets, an amendment of APB No. 29* in December 2004. The statement amends Opinion 29 by eliminating the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. SFAS No. 153 provides that a nonmonetary exchange has commercial substance if future cash flows of the entity are expected to change significantly as a result of the exchange. The statement is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. Earlier application is permitted for nonmonetary asset exchanges occurring in fiscal periods beginning after the date of the issuance of the statement. Retroactive application is not permitted. Management is analyzing the requirements of SFAS No. 151 and believes that its adoption will not have any significant impact on the financial position, results of operations or cash flows of the Company.

FASB Staff Position ("FSP") No. 109-2, *Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004*, was issued in December 2004. This FSP provides guidance on accounting for special reductions in taxes included in the American Jobs Creation Act of 2004. In particular, the Act allows a one-time decrease in U.S. Federal taxes on repatriated foreign earnings. FSP No. 109-2 clarifies that a company's consideration of the Act does not overrule their prior contention that the foreign earnings were permanently reinvested. Also, this FSP indicates that companies should provide tax expense when a decision is made to repatriate some or all foreign earnings, and provide disclosure about the possible range of repatriation if the analysis is not yet complete. Quicksilver repatriated $86.5 million as the result of a Canadian dividend distribution in 2004 and provided approximately $0.8 million of current income tax expense in 2004.

In September 2004, the SEC issued Staff Accounting Bulletin ("SAB") No. 106. This pronouncement requires companies that use the full cost method of accounting for oil and gas producing activities to include an estimate of future asset retirement costs to be incurred as a result of future development activities on proved reserves in their calculation of depreciation, depletion and amortization. It also requires full cost companies to exclude any cash outflows associated with settling asset retirement obligations from their full cost ceiling test calculation. In addition, it requires specific disclosures regarding the impact of asset retirement obligations on oil and gas producing activities, ceiling test calculations and depreciation, depletion and amortization calculations. The Company will adopt the provisions of this pronouncement in the first quarter of 2005. Management believes there will be no immediate effect on the Company's consolidated financial statements.

3. ASSET RETIREMENT OBLIGATIONS

The FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*, which became effective for fiscal years beginning after June 15, 2002. This statement, adopted by the Company as of January 1, 2003, establishes accounting and reporting standards for the legal obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction or development and the normal operation of long-lived assets. It requires that the fair value of the liability for asset retirement obligations be recognized 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 obligation 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.

In connection with adoption of SFAS No. 143, all asset retirement obligations of the Company were identified and the fair value of the retirement costs were estimated as of the date the long-lived assets were placed into service. The asset retirement obligations' fair values were then estimated as of January 1, 2003. At January 1, 2003, the Company recognized asset retirement costs of $10.8 million and asset retirement obligations of $13.3 million, of which $0.9 million was classified as current. The cumulative-effect adjustment of $2.3 million included $1.3 million for additional depletion and depreciation of the asset retirement costs, $2.2 million for accretion of the fair value of the asset retirement obligations and $1.2 million for deferred tax benefits. The asset retirement obligation would have been $12.6 million at January 1, 2002 had FAS No. 143 then been in effect.

The following table reflects pro forma income for all periods assuming that SFAS No. 143 was applied retroactively.

	For the Year Ended December 31,		
	2004	2003	2002
	(in thousands)		
Income before cumulative effect of change in accounting principle	$31,272	$18,505	$13,835
Deduct: accretion of asset retirement obligation and depletion and depreciation of associated fixed assets, net of income taxes	—	—	(523)
Pro forma net income before cumulative effect of change in accounting principle	$31,272	$18,505	$13,312
Pro forma net income—per share			
Basic	$ 0.63	$ 0.41	$ 0.34
Diluted	0.62	0.41	0.33

The following table provides a reconciliation of the changes in the estimated asset retirement obligation from the amount recorded upon adoption of SFAS No. 143 on January 1, 2003 through December 31, 2004.

	2004	2003
	(in thousands)	
Beginning asset retirement obligation	$15,189	$13,326
Additional liability incurred	2,538	999
Accretion expense	982	739
Sale of properties	(680)	—
Asset retirement costs incurred	(267)	(39)
Loss on settlement of liability	143	—
Currency translation adjustment	566	164
Ending asset retirement obligation	$18,471	$15,189

During the years ended December 31, 2004 and 2003, accretion expense was recognized and included in depletion, depreciation and accretion expense reported in the statement of income for the year. There have not been any revisions to either the timing or the amount of the original estimate of undiscounted cash flows during 2003 or 2004. Asset retirement obligations at December 31, 2004 and 2003 are $18.5 million and $15.2 million, respectively, of which $504,000 and $54,000, respectively, has been classified as current.

4. 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 2004, the Company entered into both fixed and floating price firm natural gas sale and purchase commitments and associated financial price swaps that extend through March 2005. The derivative transactions qualify as fair value hedges. Hedge ineffectiveness resulted in $118,000 of net losses, $188,000 of net gains and $26,000 of net losses in 2004, 2003 and 2002, respectively.

During 2002, the Company cancelled three interest rate swap agreements. The first, covering its $53 million of Second Mortgage Notes ("Subordinated Notes"), was cancelled on July 15, 2002 and the Company received a cash settlement of $1.0 million. The swap agreement converted the debt's 14.75% fixed rate to a floating three-month LIBOR base rate and qualified as a fair value hedge. The Company deferred the $1.0 million gain resulting from the settlement, which was to be recognized through the original maturity date for the swap, March 30, 2009. The Company redeemed the $53 million in principal amount of Subordinated Notes in June 2003. At that time the remaining $0.9 million deferred gain was recognized.

In October 2002, the Company cancelled two fixed-rate interest rate swaps related to $75 million of the Company's variable-rate debt and entered into a new fixed-rate interest swap that converted the interest rate to a fixed-rate of 3.74% through March 31, 2005. The fair value of the open swap at its inception was $1.9 million. The Company recognized the $1.9 million loss associated with the cancelled swaps through the original maturity date of the swaps, March 31, 2003. At December 31, 2004 and 2003, the fair value of the open interest swap was a liability of $0.2 million and $2.0 million, respectively.

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. The fair value of the swap was $50,000 as of December 31, 2003. In January 2004, the swap position was cancelled and the Company received a cash settlement of $0.3 million that will be recognized over the original maturity date for the swap, December 31, 2006. At December 31, 2004, $0.2 million of the gain remains to be recognized.

The change in carrying value of the Company's derivatives, firm sale and purchase commitments accounted for as hedges and interest rate swaps in the Company's balance sheet since December 31, 2003 resulted from a decrease in the remaining hedged volumes partially offset by an increase in market prices for natural gas, crude oil and a decrease in the remaining period covered by the interest rate swap. 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, 2004 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 20 to 85 days.

The estimated fair values of all derivatives and the associated fixed price firm sale and purchase commitments of the Company as of December 31, 2004 and 2003 are provided below. The associated carrying values of these swaps are equal to the estimated fair values for each period presented.

	As of December 31,	
	2004	2003
	(in thousands)	
Derivative assets:		
Fixed price sale commitments	$ 314	$ 43
Natural gas financial collars	3,563	330
Crude oil financial collars	106	—
Floating price natural gas financial swaps	—	463
Fixed price natural gas financial swaps	—	336
Fixed to floating interest rate swap	—	50
	$ 3,983	$ 1,222
Derivative liabilities:		
Fixed price natural gas financial swaps	$12,066	$41,363
Floating price natural gas financial swaps	322	42
Natural gas financial collars	158	—
Crude oil financial collars	5	448
Fixed price sale commitments	—	356
Floating to fixed interest rate swap	233	2,030
	$12,784	$44,239

The fair value of all natural gas and crude derivatives and firm sale and purchase commitments accounted for as hedges as of December 31, 2004 and 2003 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 to assume the Company's contract positions. Of the $4.0 million of derivatives assets and $12.8 million of derivative liabilities, $2.4 million of assets and $12.8 million of liabilities have been classified as current at December 31, 2004 based on the maturity of the derivative instruments, resulting in $6.8 million of after-tax losses to be reclassified from accumulated other comprehensive income in 2005.

5. 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 contracts to hedge its exposure to commodity price risk associated with anticipated future natural gas and crude oil production. These contracts have included physical sales contracts and derivatives including price ceilings and floors, no-cost collars and fixed price swaps. As of December 31, 2004, Quicksilver sells approximately 25,000 Mcfd and 10,000 Mcfd of natural gas under long-term contracts with a floor of $2.49 per Mcf and $2.47 per Mcf, respectively, through March 2009. Approximately 29,700 Mcfd of the Company's natural gas production was sold under these contracts during 2004. The remaining 5,300 Mcfd sold under these contracts were third-party volumes controlled by the Company. These contracts are not considered derivatives, but rather normal sales contracts under SFAS No. 133.

The Company hedged 30,000 Mcfd natural gas production in May 2000 using fixed price swap agreements at prices averaging $2.79 per Mcf. These agreements expire in April 2005. Natural gas price collars hedge approximately 20,000 Mcfd of the Company's budgeted natural gas sales volumes for the first quarter of 2005. Natural gas price collars of nearly 33,000 Mcfd hedge the Company's budgeted natural gas sales volumes for the remainder of 2005. Additionally, the Company has used price collar agreements to hedge approximately 750 Bbld of its crude oil production for 2005. As a result of these various contracts, the Company benefits 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, 2004 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 2005-Apr 2005	10,000 Mcfd	$ 2.79	$(4,016)
Gas	Swap	Jan 2005-Apr 2005	10,000 Mcfd	2.79	(4,025)
Gas	Swap	Jan 2005-Apr 2005	10,000 Mcfd	2.79	(4,025)
Gas	Collar	Jan 2005-Mar 2005	5,000 Mcfd	5.50 – 9.60	62
Gas	Collar	Jan 2005-Mar 2005	10,000 Mcfd	5.50 – 9.63	115
Gas	Collar	Jan 2005-Mar 2005	5,000 Mcfd	5.50 – 9.90	86
Gas	Collar	Apr 2005-Oct 2005	5,000 Mcfd	5.50 – 6.75	(109)
Gas	Collar	Apr 2005-Oct 2005	10,000 Mcfd	5.50 – 6.75	(219)
Gas	Collar	May 2005-Oct 2005	15,000 Mcfd	5.50 – 7.15	(15)
Gas	Collar	May 2005-Oct 2005	5,000 Mcfd	6.50 – 8.15	624
Gas	Collar	May 2005-Oct 2005	5,000 Mcfd	6.50 – 8.22	632
Gas	Collar	Nov 2005-Mar 2006	10,000 Mcfd	6.50 – 11.20	779
Gas	Collar	Nov 2005-Mar 2006	10,000 Mcfd	6.50 – 11.20	779
Gas	Collar	Apr 2006-Oct 2006	5,000 Mcfd	5.50 – 8.10	332
Gas	Collar	Apr 2006-Oct 2006	5,000 Mcfd	5.50 – 8.25	339
Oil	Collar	Jan 2005-Jun 2005	500 Bbld	40.00 – 52.80	93
Oil	Collar	Jan 2005-Jun 2005	500 Bbld	40.00 – 46.75	(5)
Oil	Collar	Jul 2005-Dec 2005	250 Bbld	38.00 – 47.75	13
				Net open positions	$(8,560)

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 2004, 2003 and 2002 were $43.9 million, $39.8 million and $7.4 million lower, respectively, than if the hedging programs had not been in effect.

Commodity price fluctuations affect the remaining natural gas and crude oil volumes as well as the Company's NGL volumes. Natural gas volumes of 4,500 Mcfd are committed at market price through May 2005 and an additional 16,500 Mcfd of natural gas is committed at market price through September 2008. During 2004, almost 6,400 Mcfd of Quicksilver's natural gas production was sold under these contracts. An additional 14,600 Mcfd sold under these contracts were third-party volumes controlled by the Company.

The Company entered into various financial contracts to hedge exposure to commodity price risk associated with future contractual natural gas sales and purchases with derivative instruments. These contracts include either fixed and floating price sales or purchases from third parties. As a result of the firm sale and purchase commitments and associated financial price swaps, the hedge derivatives qualified as fair value hedges. Marketing revenues were $0.5 million and $0.3 million higher and lower by $2.2 million as a result of its hedging activities in 2004, 2003 and 2002, respectively.

The following table summarizes our open financial derivative positions and hedged firm commitments as of December 31, 2004 related to natural gas marketing.

Contract Period	Volume	Weighted Avg Price per Mcf	Fair Value (in thousands)
Natural Gas Sales Contracts			
Jan 2005	2,262 Mcfd	$ 7.74	$ 104
Feb 2005	3,935 Mcfd	$ 7.53	136
Mar 2005	1,935 Mcfd	$ 7.58	74
			$ 314
Natural Gas Financial Derivatives			
Jan 2005-Mar 2005	1,333 Mcfd	Floating Price	$(171)
Jan 2005-Mar 2005	333 Mcfd	Floating Price	(44)
Jan 2005	645 Mcfd	Floating Price	(35)
Feb 2005	1,428 Mcfd	Floating Price	(43)
Feb 2005	714 Mcfd	Floating Price	(17)
Mar 2005	323 Mcfd	Floating Price	(12)
			(322)
		Total-net	$ (8)

The fair values of fixed price and floating price natural gas and crude oil derivatives and associated firm commitments as of December 31, 2004 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 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, 2004, the interest payments for $75.0 million notional variable-rate debt are hedged with an interest rate swap that converts 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 and $2.0 million at December 31, 2003.

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. The asset associated with the swap was $50,000 at December 31, 2003. In January 2004, the swap position was cancelled and the Company received a cash settlement of $0.3 million that is being recognized over the original term of the swap, which ends December 31, 2006. The deferred gain remaining at December 31, 2004 is $0.2 million.

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. During October and November 2004, Quicksilver loaned MGV approximately $11.4 million. To reduce its exposure to exchange rate risk, MGV 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, MGV recognized a gain of $0.2 million.

6. ACCOUNTS RECEIVABLE

Accounts receivable consist of the following:

	As of December 31,	
	2004	**2003**
	(in thousands)	
Accrued production receivables	$24,351	$19,318
Joint interest receivables	13,247	6,478
Other receivables	753	552
Allowance for bad debts	(314)	(101)
	$38,037	$26,247

7. INVENTORIES AND OTHER CURRENT ASSETS

Inventories and other current assets consist of:

	As of December 31, 2004	As of December 31, 2003
	(in thousands)	
Inventories	$4,161	$4,595
Hedge derivatives (see note 4)	2,383	1,172
Prepaid expenses and deposits	2,145	1,821
	$8,689	$7,588

8. PROPERTIES, PLANT AND EQUIPMENT

Property and equipment includes the following:

	As of December 31, 2004	As of December 31, 2003
	(in thousands)	
Oil and gas properties		
Subject to depletion	$ 838,134	$ 665,457
Unevaluated costs	97,168	49,919
Accumulated depletion	(195,415)	(159,801)
Net oil and gas properties	739,887	555,575
Other equipment		
Pipelines and processing facilities	70,851	56,980
General properties	12,597	7,645
Accumulated depreciation	(20,725)	(15,624)
Net other property and equipment	62,723	49,001
Property and equipment, net of accumulated depreciation and depletion	$ 802,610	$ 604,576

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, 2004 and 2003 and the year in which they were incurred as follows:

	December 31, 2004 Costs Incurred During					December 31, 2003 Costs Incurred During				
	2004	2003	2002	Prior	Total	2003	2002	2001	Prior	Total
	(in thousands)					(in thousands)				
Acquisition costs	$38,051	$31,972	$8,809	$1,258	$80,090	$31,834	$11,658	$903	$1,307	$45,702
Exploration costs	16,125	845	108	—	17,078	3,337	880	—	—	4,217
Total	$54,176	$32,817	$8,917	$1,258	$97,168	$35,171	$12,538	$903	$1,307	$49,919

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, 2004, approximately $38.3 million and $39.2 million of the total unevaluated costs of $97.2 million related to the Company's Texas Barnett Shale and Canadian coal bed methane 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 $3.1 million, $2.2 million and $0.8 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Depletion per Mcfe was $0.78, $0.68 and $0.69 for the years ended December 31, 2004, 2003 and 2002, respectively.

9. OTHER ASSETS

Other assets consist of:

	As of December 31,	
	2004	2003
	(in thousands)	
Deferred financing costs	$15,018	$ 6,995
Less accumulated amortization	(5,891)	(4,634)
Net deferred financing costs	9,127	2,361
Hedge derivatives (see note 4)	1,600	50
Other	547	1,063
	$11,274	$ 3,474

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

10. ACCRUED LIABILITIES

Accrued liabilities include the following:

	As of December 31,	
	2004	2003
	(in thousands)	
Accrued capital expenditures	$18,597	$10,179
Prepayments from partners	7,607	—
Accrued operating expenses	4,382	3,498
Suspended revenue	3,834	3,577
Accrued property and production taxes	2,430	1,981
Accrued product purchases	1,421	6,626
Interest payable	1,112	522
Environmental liabilities	972	923
Other	1,549	338
	$41,904	$27,644

11. NOTES PAYABLE AND LONG-TERM DEBT

Long-term debt consists of:

	As of December 31, 2004	As of December 31, 2003
	(in thousands)	
Senior secured credit facility	$180,422	$178,000
Contingently convertible debentures, net of unamortized discount of $2,231	147,769	—
Second mortgage notes payable	70,000	70,000
Other loans	1,073	1,386
Deferred gain - fair value interest hedge	226	—
Fair value interest hedge	—	50
	399,490	249,436
Less current maturities	(356)	(339)
	$399,134	$249,097

Maturities are as follows, in thousands of dollars:

2005	$ 356
2006	70,367
2007	351
2008	—
2009	180,421
Thereafter	150,000
	$401,495

On July 28, 2004, the Company entered into a senior secured credit facility. Currently, the credit facility is a revolving facility that matures on July 28, 2009 and permits the Company to obtain revolving credit loans and letters of credit from time to time in an aggregate amount outstanding not to exceed the lesser of the borrowing base or $600 million. The current borrowing base is $300 million and is subject to annual redeterminations and certain other redeterminations, based upon several factors. The lenders' commitments under the facility are allocated between U.S. and Canadian funds, with the U.S. funds being available for borrowing by the Company and Canadian funds being available for borrowing by the Company's Canadian subsidiary, MGV Energy Inc. The Company's interest rate options under the facility include rates based on LIBOR and specified bank rates. As borrowings increase, LIBOR margins increase in specified increments from 1.125% to a maximum of 1.75%. The facility is secured by Quicksilver's oil and gas properties, and the lenders annually re-determine the global borrowing base under the facility in accordance with their customary practices for oil and gas loans based upon the estimated value of the Company's year-end proved reserves. 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. The Company was in compliance with all such covenants at December 31, 2004. The senior credit facility was also used to issue letters of credit. At December 31, 2004, the Company had $0.6 million in letters of credit and $119.1 million available under the senior revolving credit facility.

On November 1, 2004, the Company sold $150 million $1.875% convertible subordinated debentures due November 1, 2024, which are contingently convertible into 3,272,085 shares of common stock (subject to adjustment). 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 21.8139 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 until the Company's stock price is $55.01 (120 % of the conversion price per share). 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, 2004, the fair value of the $150 million in principal amount of contingently convertible debentures was $162.3 million.

On June 27, 2003, the Company redeemed $53 million in principal amount of subordinated notes payable through the issuance of $70 million in principal amount of second mortgage notes due 2006 ("the Second Mortgage Notes"). As a result of the redemption, the Company recognized additional interest expense of $3.8 million, consisting of a prepayment premium of $3.2 million and write-off of the remaining deferred financing costs of $1.5 million, partially offset by an associated deferred hedging gain of $0.9 million. A portion ($30 million) of the $70 million Second Mortgage Notes bear interest at a variable annual rate based upon the three-month LIBOR rate plus 5.48%, and the remainder ($40 million) bear interest at the fixed rate of 7.5% per annum. The Second Mortgage Notes contain restrictive covenants, which, among other things, require maintenance of a minimum current ratio of at least 1.0, a ratio of net present value of proved reserves to total debt of at least 1.8 to 1.0; and a ratio of earnings before interest, taxes, depreciation and amortization and non-cash income and expense to interest expense (consolidated net interest expense and current maturities of debt) of at least 1.25 (calculated in accordance with provisions of the Second Mortgage Notes). At December 31, 2004, the Company was in compliance with all such restrictions. At December 31, 2004, the fair value of the $70 million in principal amount of second mortgage notes approximated the face value of $70 million.

On September 11, 2003, the Company entered into a fair value interest swap covering the $40 million fixed rate 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 closed, and the Company received $0.3 million. The gain on the swap settlement will be amortized through the original term of the swap, December 31, 2006.

12. TAX CREDIT SALES

Until expiration of the tax credit at December 31, 2002, certain properties of the Company earned Internal Revenue Code Section 29 income tax credits. Code Section 29 allowed a credit against regular federal income tax liability for certain eligible gas production.

On March 31, 2000, the Company sold, to a bank, Section 29 tax credits relating to production from certain wells located in Michigan. Cash proceeds received from the sale were $25 million and were recorded as unearned revenue. Revenue was recognized as reserves were produced. The purchase and sale agreement and ancillary agreements with the bank included a production payment in favor of Quicksilver burdening future production on the properties. Revenue of $3.7 million and $9.4 million was recognized in 2002 and 2001, respectively, in other revenue. During 1997, other tax credits attributable to properties owned by the Company were conveyed through the sale of certain working interests to a bank by entities who contributed properties to the Company at the time of its formation. Revenue of $1.4 million and $1.5 million was recognized in 2002 and 2001, respectively, in other revenue.

On July 3, 2003, Quicksilver repurchased interests owned by the bank as a result of the Company's tax credit sales. Quicksilver paid $6.3 million to acquire all such interests in the Section 29 tax-eligible properties. As a result of the planned repurchase, the Company recorded, in the first quarter of 2003, a $0.5 million reduction of deferred revenue previously recognized.

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, 2004, were as follows:

2005	$2,160
2006	1,845
2007	1,283
2008	931
2009	675
Thereafter	—
Total lease commitments	$6,894

Rent expense for operating leases with terms exceeding one month was $1.5 million in 2004, $1.4 million in 2003 and $1.4 million in 2002.

As of December 31, 2004, the Company had approximately $0.6 million in letters of credit outstanding related to various state and federal bonding requirements.

On October 6, 2004, Quicksilver entered into an Incentive Arrangements Agreement (the "Agreement") with three executives of MGV and one employee of Quicksilver. The Agreement provides for the amendment and restatement of employment agreements with two MGV executives and terminates incentive agreements with the other two individuals. In addition, the Agreement provides for awards of cash bonuses based upon the achievement of specified proved reserve targets, as well as options granted under the Company's Amended and Restated 1999 Stock Option and Retention Stock Plan covering 1,183,422 shares of common stock at an exercise price of $31.27. The cash bonuses, in the aggregate, will be determined as a base amount of $5.0 million for achieving proved reserves of 400 billion cubic feet equivalent (Bcfe) at December 31, 2005. Proved reserves in excess of 400 Bcfe to but not exceeding 1,000 Bcfe will increase the cash bonuses earned by $0.05 per Mcfe. Presently, the Company has not recognized an obligation for the cash bonuses; however, the Company will continue to monitor its potential liability in respect of these matters, and will record accruals in respect of such liabilities when payment thereof becomes probable and estimable.

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. The court heard arguments on class certification on November 8, 2002, and on December 6, 2002 the court issued a memorandum opinion granting class certification in part and denying it in part. On December 20, 2002, the Company filed a motion for clarification and reconsideration of the court's order. That motion was denied on March 9, 2003. After an extended delay resulting from the retention of new counsel by the plaintiffs and the initiation of settlement discussions, on January 21, 2005, the Circuit Court issued an order certifying certain claims to proceed on behalf of a class. The Circuit Court also entered a scheduling order setting trial for January 2007, and declined Defendants' request to stay proceedings in that court pending an appeal of the certification order.

Defendants have sought leave to appeal the certification order by filing an Application for Leave to Appeal on February 11, 2005 with the Michigan Court of Appeals. Defendants have also requested that the Court of Appeals stay proceedings in the Circuit Court pending the consideration of its appeal, and have requested that the Court of Appeals consider all matters in an expedited manner. The Company is currently awaiting a ruling from that court on the application and the requests for stay and immediate consideration.

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 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. 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 MGV'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 MGV'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 MGV to Quicksilver. The distribution represented the repayment of Quicksilver's capital contributions that had been made to MGV for the period January 1, 2001 through July 27, 2004 in the amount of $114.4 million, Canadian. This dividend is to be reinvested in the U.S. under a qualified domestic reinvestment plan as defined under Internal Revenue Code Section 965 (b)(4). The funds are to be 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 has been accrued on this dividend distribution. No other deferred taxes have been accrued on MGV's undistributed earnings and the Company continues to expect that the balance of MGV's undistributed earnings will be permanently reinvested for use in the development of its oil and gas reserves.

Significant components of the Company's deferred tax assets and liabilities as of December 31, 2004 and 2003 are as follows:

	2004	2003
Current		
Deferred tax asset		
Deferred tax benefit on cash flow hedge losses	$ 3,523	$11,760
Non-current		
Deferred tax assets		
Deferred tax benefit on cash flow hedge losses	$ —	$ 3,022
Tax credit sale and unearned income	—	—
Net operating loss carry forwards	18,118	18,920
Other	233	166
Total deferred tax assets	18,351	22,108
Deferred tax liabilities		
Properties, plant, and equipment	100,845	92,818
Deferred tax liability on cash flow hedge gains	593	—
Deferred tax liability on convertible debenture interest	419	—
Total deferred tax liabilities	101,857	92,818
Net deferred tax liabilities	$ 83,506	$70,710

The provisions for income taxes for the years ended December 31, 2004, 2003 and 2002 are as follows:

	2004	2003	2002
	(in thousands)		
Current state income tax expense (benefit)	$ 70	$ 79	$ (139)
Current federal income tax expense (benefit)	814	—	(178)
Current foreign income tax expense	301	182	55
Total current income tax expense (benefit)	1,185	261	(262)
Deferred federal income tax expense	8,756	8,175	7,928
Deferred foreign income tax expense (benefit)	4,233	1,561	(168)
Total deferred income tax expense	12,989	9,736	7,760
Total	$14,174	$9,997	$7,498

A reconciliation of the statutory federal income tax rate and the effective tax rate for the years ended December 31, 2004, 2003 and 2002 are as follows:

	2004	2003	2002
U.S. federal statutory tax rate	35.00%	35.00%	35.00%
Dividend income from Canadian subsidiary	1.79%	—	—
Permanent differences	.12%	.18%	86%
State income taxes net of federal deduction	.10%	.18%	(.42)%
Foreign income taxes	(5.77)%	(.27)%	—
Other	(.05)%	(.02)%	(.29)%
Effective income tax rate	31.19%	35.07%	35.15%

Income tax benefits recognized as additional paid-in capital for the years ended December 31, 2004, 2003 and 2002 are as follows:

	2004	2003	2002
		(in thousands)	
Income tax benefit recognized on employee stock option exercises	$4,243	$739	$—

Included in deferred tax assets are net operating losses of approximately $51.8 million that are available for carryover beginning in the year 2005 to reduce future U.S. taxable income. The net operating losses will expire in 2005 through 2024. 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.

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. The Company may make discretionary contributions to the plan. Company contributions were $0.3 million, $0.2 million and $0.2 million for the years ended December 31, 2004, 2003 and 2002, respectively.

The Company initiated a self-funded health benefit plan effective July 1, 2001. 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, $1.1 million and $1.2 million for the plan years ended June 30, 2004, 2003 and 2002, respectively. Aggregate level reinsurance is in place for payment of claims up to $1 million over and above the estimated maximum claim liability of $2.1 million for the plan year ending June 30, 2005. Administrative expenses for the plan years ended June 30, 2004, 2003 and 2002 were $0.4 million, $0.4 million and $0.3 million, respectively.

16. STOCKHOLDERS' EQUITY

Stock Split

On June 1, 2004, the Company announced that its Board of Directors declared a two-for-one split of the Company's outstanding common stock effected in the form of a stock dividend. The stock dividend was payable on June 30, 2004, to stockholders of record at the close of business on June 15, 2004. The split did not affect treasury shares.

The capital stock accounts, all share data and earnings per share data included in the consolidated financial statements and notes give effect to the stock split, applied retroactively, to all periods presented.

Common Stock, Preferred Stock and Treasury Stock

The Company is authorized to issue 100 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, 2004, the Company had 50,122,360 shares of common stock outstanding (including 172,626 shares issuable upon exchange of the MGV exchangeable shares and excluding treasury shares) and one share of special voting preferred stock outstanding.

In connection with the December 2000 MGV minority interest acquisition, all issued and outstanding shares of MGV capital stock, other than those held by Quicksilver, were converted into 567,338 MGV exchangeable shares. Each MGV exchangeable share is a non-voting share of MGV's capital stock exchangeable for one share of Quicksilver common stock. Redemption or exchange can occur as a result of (i) liquidation of MGV; (ii) exercise of a redemption right by an MGV shareholder requiring MGV to purchase exchangeable shares; or (iii) exercise of an exchange put right by an MGV shareholder requiring Quicksilver to exchange the exchangeable shares for Quicksilver common stock. Any MGV exchangeable shares still outstanding on December 31, 2005 will be treated as having been the subject of an exercise of an exchange put right on that date. Upon exchange, the holder of exchangeable shares is entitled to receive one share of Quicksilver common stock and the full amount of all cash dividends declared on a share of Quicksilver common stock from the date of issuance of the exchangeable share to the date of exchange. In order to provide voting rights to holders of MGV exchangeable shares equivalent to the voting rights of the Quicksilver common shares, Quicksilver created, on December 15, 2000, a series of its preferred stock designated as Special Voting Stock. Quicksilver issued a single share of Special Voting Stock to an appointee. Through December 31, 2004, 27,000 exchangeable shares of MGV have been presented to MGV for redemption for $248,343 and 394,712 MGV exchangeable shares have been exchanged for shares of Quicksilver common stock.

The following table shows common share and treasury share activity since January 1, 2002:

	Common Shares Issued	Treasury Shares Held
Opening Balance January 1, 2002	41,317,898	3,751,852
Stock options exercised	299,894	—
Warrants exercised	1,971,500	—
MGV Class C Retraction	(20,000)	—
Treasury stock purchased	—	5,750
Treasury stock issued	1,187,100	(1,187,100)
Balance at December 31, 2002	44,756,392	2,570,502
Stock options exercised	289,334	8,402
Stock issuance	7,000,000	—
Balance at December 31, 2003	52,045,726	2,578,904
Stock options exercised	645,245	(10,293)
Balance at December 31, 2004	52,690,971	2,568,611

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. 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 $50.00.

The rights will be exercisable only if such a person or group acquires 15 percent 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 percent or more of the common stock of the Company. This 15 percent threshold does not apply to certain members of the Darden family who collectively owned, directly or indirectly, approximately 37% of the Company's common stock at December 31, 2004.

If an Acquiring Person acquires 15 percent 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 percent 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 fifteen percent or more of the common stock of Quicksilver, the rights are redeemable for $0.005 per right at the option of the board of directors of the Company.

Stock Option 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, 2.6 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 2.4 million shares were reserved for issuance pursuant to the 1999 Plan.

In April 2004, the Board of Directors adopted the Company's 2004 Non-Employee Director Stock Option Plan (the "2004 Plan"), which was approved at the annual stockholders' meeting held in May 2004. There were 500,000 shares reserved under the 2004 Plan, which provides for the grant of non-qualified options to Quicksilver's outside directors.

Under terms of the 1999 Plan and 2004 Plan, options may be granted to officers, employees and non-employee directors at an exercise price that is 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. A summary of stock option transactions under the plans is as follows:

	2004		2003		2002	
	Shares	Wtd Avg Exercise Price	Shares	Wtd Avg Exercise Price	Shares	Wtd Avg Exercise Price
Outstanding at beginning of year	1,258,712	$ 4.45	1,476,422	$ 3.75	1,692,174	$2.94
Granted	1,844,496	26.98	104,188	11.45	138,506	8.51
Exercised	(655,538)	3.47	(297,736)	3.18	(337,694)	2.43
Cancelled	—	—	—	—	(12,564)	3.56
Forfeited	(11,500)	16.52	(24,162)	8.46	(4,000)	8.51
Outstanding at end of year	2,436,170	$21.50	1,258,712	$ 4.45	1,476,422	$3.75
Exercisable at end of year	583,163	$ 4.96	913,848	$ 3.83	770,314	$3.33
Weighted average fair value of options granted		$ 9.93		$ 6.18		$3.69

Pro forma information regarding net income and earnings per share is required by SFAS No. 123, and has been determined as if the Company had accounted for its employee stock options under the fair value method of that statement. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions:

	2004	2003	2002
Wtd avg grant date	Jul 6, 2004	Feb 21, 2003	Feb 5, 2002
Risk-free interest rate	2.7%	2.8%	3.0%
Expected life (in years)	4.1	6.0	3.5
Expected volatility	45.4%	54.9%	55.6%
Dividend yield	—	—	—

The following table summarizes information about stock options outstanding at December 31, 2004.

	Options Outstanding			Options Exercisable	
Range of Exercisable Prices	**At 12/31/04**	**Wtd Avg Remaining Contractual Life**	**Wtd Avg Exercise Price**	**At 12/31/04**	**Wtd Avg Exercise Price**
$ 1-2	325,424	0.1	$ 1.84	325,424	$ 1.84
4-7	47,536	1.1	4.90	47,536	4.90
8-10	145,392	2.0	8.22	145,392	8.22
11-13	87,822	3.1	11.41	55,837	11.62
16-24	576,814	4.0	16.71	8,974	23.75
31-36	1,253,182	3.1	31.52	—	—
	2,436,170	2.8	$21.50	583,163	$ 4.96

17. OTHER REVENUE

Other revenue consists of the following:

	For the Years Ended December 31,		
	2004	**2003**	**2002**
	(in thousands)		
Tax credit revenue	$ 221	$ (582)	$5,129
Marketing	928	1,208	3,021
Processing and transportation	1,407	1,286	1,533
	$2,556	$1,912	$9,683

18. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid for interest and income taxes is as follows:

	For the Years Ended December 31,		
	2004	**2003**	**2002**
	(in thousands)		
Interest	$14,742	$19,543	$19,730
Income taxes	72	66	147

Other non-cash transactions are as follows:

	For the Years Ended December 31,		
	2004	2003	2002
	(in thousands)		
Distribution of equity to Mercury Exploration Company	$ —	$(515)	$—
Tax benefit recognized on employee stock option exercises	4,243	739	—
Treasury stock (acquired) reissued:			
10,293 shares for non-employee director stock option exercise	189	—	—
8,402 shares for employee stock option exercise	—	(200)	—
74,200 shares for payment of executives' compensation	—	—	364

19. RELATED PARTY TRANSACTIONS

As of December 31, 2004, members of the Darden family, Mercury Exploration Company and Quicksilver Energy L.P., entities that are owned by members of the Darden family, beneficially owned approximately 37% of the Company's outstanding common stock. Thomas Darden, Glenn Darden and Anne Darden Self are officers and directors of the Company.

During 2002, Quicksilver paid $0.85 million and $0.90 million, respectively, for principal and interest on the note payable to Mercury associated with the 2000 acquisition of assets from Mercury. During 2003, Quicksilver paid Mercury $2.05 million principal and interest to retire the note. Quicksilver and its associated entities paid $0.86 million, $0.78 million and $0.74 million for rent in 2004, 2003 and 2002, respectively, on buildings which are owned by a Mercury affiliate. Rental rates were determined based on comparable rates charged by third parties.

Effective July 1, 2000, Quicksilver purchased the natural gas producing, gathering, transmission and marketing assets of Mercury, including 65% of Voyager Compression Services, LLC ("Voyager"), a gas compression company, from Mercury for $18 million. An independent appraiser determined the fairness, from a financial point of view, of the $18 million purchase price and the disinterested members of the Board of Directors approved the purchase. Mercury continued to own 33% of Voyager, and Jeff Cook, an officer of the Company, 2%. Quicksilver accounted for its 65% holdings in Voyager under the equity method since control over Voyager was shared equally with Mercury.

During 2002, Quicksilver purchased compressors and equipment for $3.7 million and maintenance and related services for $1.8 million from Voyager at terms as favorable as those granted by Voyager to third parties. Also in 2002, Voyager recognized an impairment loss of $0.9 million related to its inventory, fixed assets and operating leases for facilities. Subsequently, Voyager sold, to a third party, its Michigan inventory and fixed assets and recognized a gain on the sale of $0.2 million. Quicksilver recognized its proportionate share of these items during 2002.

Voyager sold its compressor service fixed assets and the majority of its Texas inventory to Quicksilver for $1.6 million (its historical cost that approximated fair value) in February 2003. In addition, Quicksilver paid Voyager $2.2 million for the fair value of its compressor service contracts. After completion of the sale of the service contracts and other assets, Quicksilver received a $0.2 million cash distribution from Voyager and recorded a $0.5 million equity distribution to Mercury for its share of Voyager's gain from the disposition of the Compressor service contracts to Quicksilver. The transaction was reviewed and approved by the disinterested members of the Board of Directors. Mercury's portion of the gain on the sale of the service contracts was treated as an equity distribution by Quicksilver as Mercury and the Darden family are considered as having a controlling interest in Quicksilver. Quicksilver's gain on the sale of the contracts was eliminated.

During 2003, Voyager also sold, to a Mercury affiliate, leasehold improvements on operating leases with that Mercury affiliate at historical cost, which approximates fair value, of approximately $0.8 million. The leases were cancelled, and Voyager's lease cancellation costs were $0.4 million.

20. 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
2004				
Revenues	$136,580	$ 43,149	$ —	$179,729
Depletion, depreciation and accretion	30,808	9,282	601	40,691
Operating income	50,763	23,465	(13,535)	60,693
Fixed assets—net	581,575	219,369	1,666	802,610
Expenditures for assets	126,512	104,580	665	231,757
2003				
Revenues	$129,235	$ 11,714	$ —	$140,949
Depletion, depreciation and accretion	29,036	2,562	469	32,067
Operating income (loss)	51,898	5,202	(8,602)	48,498
Fixed assets—net	496,102	106,789	1,685	604,576
Expenditures for assets	78,936	69,297	255	148,488
2002				
Revenues	$119,917	$ 2,062	$ —	$121,979
Depletion, depreciation and accretion	28,932	675	552	30,159
Operating income (loss)	49,143	(337)	(8,104)	40,702
Fixed assets—net	436,195	31,984	1,899	470,078
Expenditures for assets	73,480	15,161	324	88,965

21. SUPPLEMENTAL INFORMATION (UNAUDITED)

Proved oil and gas reserves estimates were prepared by independent petroleum engineers with Schlumberger Data and Consulting Services, LaRoche Petroleum Consultants, Ltd. and Netherland, Sewell & Associates, Inc. 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, 2002, 2003 and 2004 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, 2001	535,009	16,513	551,522	13,344	—	13,344	1,538	—	1,538
Revisions	40,288	1,375	41,663	2,153	—	2,153	214	—	214
Extensions and discoveries	30,330	36,649	66,979	1,444	—	1,444	619	—	619
Purchases in place	64,267	—	64,267	25	—	25	1	—	1
Sales in place	—	—	—	(59)	—	(59)	—	—	—
Production	(31,910)	(935)	(32,845)	(905)	—	(905)	(156)	—	(156)
December 31, 2002	637,984	53,602	691,586	16,002	—	16,002	2,216	—	2,216
Revisions	(9,137)	2,363	(6,774)	(2,022)	1	(2,021)	(165)	2	(163)
Extensions and discoveries	45,081	93,591	138,672	—	—	—	—	—	—
Purchases in place	1,204	—	1,204	—	—	—	—	—	—
Production	(31,612)	(2,924)	(34,536)	(807)	(1)	(808)	(133)	(2)	(135)
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
Proved developed reserves									
December 31, 2002	550,889	22,750	573,639	10,722	—	10,722	1,524	—	1,524
December 31, 2003	569,978	83,698	653,676	8,734	—	8,734	1,405	—	1,405
December 31, 2004	556,999	149,453	706,453	4,587	—	4,587	2,464	—	2,464

The capitalized costs relating to oil and gas producing activities and the related accumulated depletion, depreciation and accretion as of December 31, 2004, 2003 and 2002 were as follows:

	United States	Canada	Consolidated
		(in thousands)	
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
2003			
Proved properties	$ 577,322	$ 88,135	$ 665,457
Unevaluated properties	27,110	22,809	49,919
Accumulated DD&A	(155,183)	(4,618)	(159,801)
Net capitalized costs	$ 449,249	$106,326	$ 555,575
2002			
Proved properties	$ 524,947	$ 20,431	$ 545,378
Unevaluated properties	3,888	13,025	16,913
Accumulated DD&A	(129,194)	(1,712)	(130,906)
Net capitalized costs	$ 399,641	$ 31,744	$ 431,385

Costs incurred in oil and gas property acquisition, exploration and development activities during the years ended December 31, 2004, 2003 and 2002 were as follows:

	United States	Canada	Consolidated
		(in thousands)	
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
2003			
Proved acreage	$ 3,215	$ 3,388	$ 6,603
Unproved acreage	24,063	6,739	30,802
Development costs	37,682	41,820	79,502
Exploration costs	9,411	17,066	26,477
Total	$ 74,371	$ 69,013	$143,384
2002			
Proved acreage	$ 32,199	$ —	$ 32,199
Unproved acreage	550	5,422	5,972
Development costs	34,178	938	35,116
Exploration costs	5,925	8,659	14,584
Total	$ 72,852	$ 15,019	$ 87,871

Results of operations from producing activities for the years ended December 31, 2004, 2003 and 2002 are set forth below:

	United States	Canada	Consolidated
		(in thousands)	
2004			
Natural gas, crude oil & NGL sales	$134,268	$42,905	$177,173
Oil & gas production expense	54,784	10,402	65,186
Depletion expense	26,444	8,981	35,425
	53,040	23,522	76,562
Income tax expense	18,564	7,908	26,472
Results from producing activities	$ 34,476	$15,614	$ 50,090
2003			
Natural gas, crude oil & NGL sales	$127,339	$11,698	$139,037
Oil & gas production expense	48,243	3,951	52,194
Depletion expense	25,600	2,428	28,028
	53,496	5,319	58,815
Income tax expense	18,724	1,788	20,512
Results from producing activities	$ 34,772	$ 3,531	$ 38,303
2002			
Natural gas, crude oil & NGL sales	$110,291	$ 2,005	$112,296
Oil & gas production expense	40,505	1,723	42,228
Depletion expense	26,352	601	26,953
	43,434	(319)	43,115
Income tax expense	15,199	(138)	15,061
Results from producing activities	$ 28,235	$ (181)	$ 28,054

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,		
	2004	2003	2002
Natural gas—Henry Hub-Spot	$ 6.18	$ 5.97	$ 4.74
Natural gas—AECO	5.18	5.32	2.92
Crude oil—WTI Cushing	43.36	32.55	31.20

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, 2004, 2003 and 2002 were as follows:

	United States	Canada (in thousands)	Consolidated
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
2003			
Future revenues	$ 4,125,685	$ 746,722	$ 4,872,407
Future production costs	(1,342,167)	(122,164)	(1,464,331)
Future development costs	(117,330)	(60,696)	(178,026)
Future income taxes	(851,337)	(162,636)	(1,013,973)
Future net cash flows	1,814,851	401,226	2,216,077
10% discount—calculated difference	(1,120,056)	(247,280)	(1,367,336)
Standardized measure of discounted future net cash flows relating to proved reserves	$ 694,795	$ 153,946	$ 848,741
2002			
Future revenues	$ 3,354,927	$ 206,602	$ 3,561,529
Future production costs	(1,260,500)	(40,504)	(1,301,004)
Future development costs	(96,748)	(14,373)	(111,121)
Future income taxes	(616,865)	(52,680)	(669,545)
Future net cash flows	1,380,814	99,045	1,479,859
10% discount—calculated difference	(802,968)	(62,040)	(865,008)
Standardized measure of discounted future net cash flows relating to proved reserves	$ 577,846	$ 37,005	$ 614,851

The primary changes in the standardized measure of discounted future net cash flows for the years ended December 31, 2004, 2003 and 2002 were as follows:

	As of December 31,		
	2004	2003	2002
	(in thousands)		
Net changes in price and production costs	$ (82,974)	$140,623	$ 358,878
Development costs incurred	61,069	44,167	35,116
Revision of estimates	(30,509)	(27,901)	63,866
Changes in estimated future development costs	3,183	(12,703)	(63,980)
Purchase and sale of reserves, net	(23,367)	1,832	63,539
Extensions and discoveries	219,656	170,660	87,555
Net change in income taxes	(21,638)	(99,013)	(162,889)
Sales of oil and gas net of production costs	(111,987)	(86,843)	(70,068)
Accretion of discount	120,065	86,775	35,895
Other	(11,508)	16,293	(2,003)
Net increase	$ 121,990	$233,890	$ 345,909

22. SELECTED QUARTERLY DATA (UNAUDITED)

	Mar 31	Jun 30	Sep 30	Dec 31
	(In thousands, except per share data)			
2004				
Operating revenues	$39,777	$41,980	$45,544	$52,428
Operating income	12,012	13,172	16,109	19,400
Net income	5,937	7,500	7,889	9,946
Basic net income per share	$ 0.12	$ 0.15	$ 0.16	$ 0.20
Diluted net income per share	0.12	0.15	0.16	0.19
2003				
Operating revenues	$37,516	$33,095	$33,513	$36,825
Operating income	14,915	10,102	11,643	11,838
Income before effect of accounting change	6,412	1,109	5,229	5,755
Net income	4,115	1,109	5,229	5,755
Basic income per share before effect of accounting change	$ 0.15	$ 0.03	$ 0.12	$ 0.12
Basic net income per share	0.10	0.03	0.12	0.12
Diluted income per share before effect of accounting change	0.15	0.03	0.11	0.11
Diluted net income per share	0.10	0.03	0.11	0.11

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, 2004, our internal control over financial reporting is effective. Our independent auditors, Deloitte & Touche LLP, have audited our consolidated financial statements and 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, 2004 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, 2004, 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, 2004, 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, 2004, 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, 2004 of the Company and our report dated March 16, 2005 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Fort Worth, Texas
March 16, 2005

ITEM 9B. Other Information

None.

PART III

ITEM 10. Directors and Executive Officers of the Registrant

The information concerning our directors is set forth under "Corporate Governance Matters—the Board of Directors" in the proxy statement for our May 17, 2005 annual meeting of stockholders is incorporated herein by reference. The information concerning any changes to the procedure by which security holder may recommend nominees to the board of directors is set forth under "Corporate Governance Matters – Committees of the Board" in the proxy statement for our May 17, 2005 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 17, 2005 annual meeting of stockholders is incorporated herein by reference.

The information concerning our audit committee is set forth under "Corporate Governance Matters – Committees of the Board" in the proxy statement for our May 17, 2005 annual meeting of stockholders is incorporated herein by reference.

The information regarding our Code of Ethics is set forth under "Corporate Governance Matters—Corporate Governance Principles, Processes and Code of Business Conduct and Ethics" in the proxy statement for our May 17, 2005 annual meeting of stockholders is incorporated herein by reference.

ITEM 11. Executive Compensation

The information set forth under "Executive Compensation" in our proxy statement for our May 17, 2005 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 17, 2005 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 17, 2005 annual meeting of stockholders is incorporated herein by reference.

ITEM 13. Certain Relationships and Related Transactions

The information set forth under "Transactions with Management and Certain Stockholders" in the proxy statement for our May 17, 2005 annual meeting of stockholders is incorporated herein by reference.

ITEM 14. Principal Accountant Fees and Services

The information set forth under "Independent Public Accountants" in the proxy statement for our May 17, 2005 annual meeting of stockholders is incorporated herein by reference.

PART IV

ITEM 15. Exhibits and Financial Statement Schedules

(a) 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 52 through 94 of this Form 10-K.

   Report of Independent Registered Public Accounting Firm

   Consolidated Balance Sheets as of December 31, 2004 and 2003

   Consolidated Statements of Income for the years ended December 31, 2004, 2003 and 2002

   Consolidated Statements of Stockholders' Equity and Comprehensive Income for the years ended December 31, 2004, 2003 and 2002

   Consolidated Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002

   Notes to Consolidated Financial Statements for the Years Ended December 31, 2004, 2003 and 2002

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.

(b) Exhibits:

Exhibit No.	Sequential Description
3.1	Second Restated Certificate of Incorporation of Quicksilver Resources Inc. (filed as Exhibit 3.1 to the Company's Form 8-K filed August 30, 2004 and included herein by reference).
3.2	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).
3.3	Amendment to the Bylaws of Quicksilver Resources Inc. adopted on November 30, 1999 (filed as Exhibit 3.4 to the Company's Form 10-K filed March 27, 2001 and included herein by reference).
3.4	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).
3.5	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	Rights Agreement, dated as of March 11, 2003, between Quicksilver Resources Inc. and Mellon Investor Services LLC, as Rights Agent (filed as Exhibit 4.1 to the Company's Form 8-A filed March 14, 2003 and included herein by reference).
4.2	Indenture Agreement for 1.875% Convertible Subordinated Debentures Due 2024, dated as of November 1, 2004 by and between Quicksilver Resources Inc., as Issuer, and JPMorgan Chase Bank, as Trustee (filed as Exhibit 4.1 to the Company's Form 8-K filed November 1, 2004 and included herein by reference).
10.1	Master Gas Purchase and Sale Agreement dated March 1, 1999, by and 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).

Exhibit No.	Sequential Description
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 on 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 10.1 to the Company's Form 8-K, filed March 11, 2005 and included herein by reference).
+ 10.4	Form of Incentive Stock Option Agreement for 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 for 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 for the Quicksilver Resources Inc. Amended and Restated 1999 Stock Option and Stock Retention Share Agreement (filed as Exhibit 10.2 to the Company's Form 8-K filed March 11, 2005 and included herein by reference).
+ 10.7	Quicksilver Resources Inc. 2004 Non-Employee Director Stock Option Plan (filed as Appendix D to the Company's proxy statement filed April 21, 2004 and included herein by reference).
+ 10.8	Form of Non-Qualified Stock Option Agreement for the Quicksilver Resources Inc. Amended and Restated 2004 Non-Employee Directors Stock Option Plan (filed as Exhibit 10.4 to the Company's Form 8-K filed January 28, 2005 and included herein by reference).
+ 10.9	Description of Quicksilver Resources Inc. 2004 Bonus Plan (filed as Exhibit 10.1 to the Company's Form 8-K filed January 28, 2005 and included herein by reference).
+10.10	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).
+10.11	Key Employee Change in Control Retention Incentive Plan (filed as Exhibit 10.2 to the Company's Form 8-K, filed August 30, 2004 and included herein by reference).
+10.12	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).
+10.13	Incentive Arrangements Agreement, dated as of September 24, 2004, among Quicksilver Resources Inc., MGV Energy Inc., J. Michael Gatens, George W. Voneiff, Brown Howard and Peter A. Bastian (filed as Exhibit 10.1 to the Company's Form 8-K, filed October 12, 2004 and included herein by reference).
10.14	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).
10.15	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).
10.16	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).

Exhibit No.	Sequential Description
*10.17	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.
10.18	Note Purchase Agreement, dated June 27, 2003, between the Company and the Purchasers identified therein (filed as Exhibit 4.2 to the Company's Form 10-Q filed August 14, 2003 and included herein by reference).
10.19	First Amendment to Note Purchase Agreement, dated as of January 30, 2004, between the Company and the Purchasers identified therein. (filed as Exhibit 4.1 to the Company's Form 10-Q dated May 7, 2004 and included herein by reference).
10.20	Second Amendment to Note Purchase Agreement, dated as of July 28, 2004, among Quicksilver Resources Inc., certain of its subsidiaries listed therein, BNP Paribas, Collateral Agent, and the Purchasers identified therein (filed as Exhibit 4.1 to the Company's Form 10-Q filed August 6, 2004 and included herein by reference).
10.21	Third Amendment to Note Purchase Agreement, dated as of September 14, 2004, among Quicksilver Resources Inc., certain of its subsidiaries listed therein, BNP Paribas, Collateral Agent, and the Purchasers identified therein (filed as Exhibit 10.1 to the Company's Form 8-K filed September 20, 2004 and included herein by reference).
* 21.1	List of subsidiaries of Quicksilver Resources Inc.
* 23.1	Consent of Deloitte & Touche LLP.
* 23.2	Consent of Schlumberger Data and Consulting Services.
* 23.3	Consent of LaRoche Petroleum Consultants, Ltd.
* 23.4	Consent of Netherland, Sewell & Associates, Inc.
* 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 16, 2005

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 16, 2005
/s/ GLENN DARDEN Glenn Darden	President and Chief Executive Officer (Principal Executive Officer); Director	March 16, 2005
/s/ BILL LAMKIN Bill Lamkin	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 16, 2005
/s/ D. WAYNE BLAIR D. Wayne Blair	Vice President and Controller (Principal Accounting Officer)	March 16, 2005
/s/ ANNE DARDEN SELF Anne Darden Self	Director	March 16, 2005
/s/ D. RANDALL KENT D. Randall Kent	Director	March 16, 2005
/s/ STEVEN M. MORRIS Steven M. Morris	Director	March 16, 2005
/s/ W. YANDELL ROGERS, III W. Yandell Rogers, III	Director	March 16, 2005
/s/ MARK J. WARNER Mark J. Warner	Director	March 16, 2005

Quicksilver Resources Inc. Corporate Information

DIRECTORS

Thomas F. Darden
Chairman

Glenn Darden

James A. Hughes

D. Randall Kent*

Steven M. Morris*

W. Yandell Rogers III*

Anne D. Self

Mark Warner*

OFFICERS

Thomas F. Darden
Chairman

Glenn Darden
President & Chief Executive Officer

Bill M. Lamkin
Executive Vice President & Chief Financial Officer

Jeff Cook
Senior Vice President – Operations

Mark D. Whitley
Vice President – Operations

Robert N. Wagner
Vice President – Reserve Group

D. Wayne Blair
Vice President & Controller

John C. Cirone
Vice President – General Counsel & Secretary

Anne D. Self
Vice President – Human Resources

MarLu Hiller
Treasurer

HEADQUARTERS

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Fort Worth, Texas 76104
P: 817.665.5000 F: 817.665.5004
quicksilver@qrinc.com
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MAJOR SUBSIDIARIES

MGV Energy Inc.
One Palliser Square
[illegible] 9th Avenue, SE
Calgary, Alberta Canada T2G 0P8
P: 403.537.2455 F: 403.262.6115

J. Michael Gatens
Chairman of the Board & Chief Executive Officer

George W. Voneiff
President

Dana W. Johnson
Senior Vice President & Chief Operating Officer

REGISTRAR AND TRANSFER AGENT

Mellon Investor Services
Stock Transfer Department
85 Challenger Road, Overpeak Centre
Ridgefield Park, New Jersey 07660
[illegible]
www.melloninvestor.com

AUDITORS

Deloitte & Touche LLP
[illegible] Commerce Street, Suite 2950
Fort Worth, Texas 76104

ANNUAL MEETING

The Company's Annual Meeting of Shareholders is scheduled for 9:00 a.m., May 17, 2005 at the Fort Worth Club, 306 W. 7th Street, Fort Worth, Texas.

The certifications of Quicksilver's Chief Executive Officer and Chief Financial Officer required under Section 302 of the Sarbanes-Oxley Act have been filed as exhibits 31.1 and 31.2, respectively, to the Annual Report on Form 10-K for the fiscal year ended December 31, 2004. Additionally, in 2004 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; 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.

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

QUICKSILVER

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KWK