EQUITY OIL CO
Form 10-K
March 15, 2004
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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, 2003

OR

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

Commission file number 0-610

EQUITY OIL COMPANY

(Exact name of registrant as specified in its charter)

Colorado	**87-0129795**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**
10 West 300 South, Suite 806	
Salt Lake City, Utah	**84101**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (801) 521-3515

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

Title of each class	Name of each exchange on which registered
None	**None**

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

Common Stock (par value, $1 per share)

(Title of class)

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 (§ 229.405 of this chapter) 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 Rule 12b-2 of the Act) Yes ¨ No x

As of March 1, 2004, 12,029,936 common shares were outstanding and the aggregate market value of voting stock held by non-affiliates of the registrant, based upon the last sale price of such stock on the last business day of the registrant s most recently completed second fiscal quarter (June 30, 2003), was approximately $26,990,000.

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PART I

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PART I

Forward Looking Statements

This report contains statements that we believe to be forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements other than historical facts, including, without limitation, statements regarding our future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and debt levels, and plans and objectives of management for future operations, are forward-looking statements. When used in this report, words such as we expect, intend, plan, estimate, anticipate, believe or should negative thereof or variations thereon or similar terminology, are generally intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements. Some, but not all, of the risks and uncertainties include: the uncertainties relating to and consequences of completing a proposed transaction (described in more detail below) with Whiting Petroleum Corporation (Whiting); declines in oil or natural gas prices; our level of success in exploitation, exploration, development and production activities; our ability to obtain external capital to finance acquisitions; our ability to identify and complete acquisitions and to successfully integrate acquired businesses; unforeseen underperformance of or liabilities associated with acquired properties; inaccuracies of our reserve estimates or our assumptions underlying them; failure of our properties to yield oil or natural gas in commercially viable quantities; uninsured or underinsured losses resulting from our oil and natural gas operations; our inability to access oil and natural gas markets due to market conditions or operational impediments; the impact and costs of compliance with laws and regulations governing our oil and natural gas operations; risks related to our level of indebtedness and periodic redeterminations of our borrowing base under our credit facility; our ability to replace our oil and natural gas reserves; any loss of our senior management or technical personnel; competition in the oil and natural gas industry; and risks arising out of any hedging transactions we have entered into or may enter into in the future. We assume no obligation, and disclaim any duty, to update the forward-looking statements in this report.

ITEM 1. Business

General

Equity Oil Company is an independent energy company engaged in oil and natural gas exploration, production and acquisition activities. We were originally incorporated in the state of Utah in 1923. In 1958, we merged into our subsidiary Weber Oil Company, a Colorado corporation, moved our state of incorporation to Colorado and changed our name to Equity Oil Company.

This annual report is for the period ended December 31, 2003, and describes our operations, assets and prospects as of that date. On February 1, 2004, we entered into an agreement and plan of merger with Whiting and WPC Equity Acquisition Corp., a wholly owned subsidiary of Whiting, pursuant to which we will become a wholly-owned subsidiary of Whiting. This transaction is described in more detail below and in our joint press release with Whiting attached as an exhibit to our current report on Form 8-K dated February 2, 2004. See Item 13 of this report and Note 12 to the financial statements included elsewhere in this report for additional information. Consummation of the merger, which is subject to customary conditions, including the approval of our shareholders, is expected to occur late in the second quarter of 2004.

We currently conduct business in seven states and one Canadian province. Our headquarters are located in Salt Lake City, Utah, and our telephone number there is (801) 521-3515. We also maintain a technical office in Denver, Colorado, and an operations office in Cody, Wyoming. We focus our operations in the Rocky Mountains, Northern California s Sacramento Basin, and the Cessford area in Alberta, Canada.

At December 31, 2003, we had 28.1 billion cubic feet of natural gas in proved reserves, compared to 36.6 billion cubic feet of natural gas of proved reserves at December 31, 2002. Our crude oil and natural gas liquid reserves at December 31, 2003 totaled 9.9 million barrels, compared to 10.5 million barrels at the end of 2002. Of our proved reserves, approximately 33% are gas and approximately 79% are categorized as proved developed. At December 31, 2003, the net present value of our reserves (using year-end prices and costs held constant and discounted at 10%) was $94 million.

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At December 31, 2003, our exploration and production operations were comprised of working interests in 742 gross (142.13 net) producing oil and gas wells. We operated 129 of these wells. As of that date, we also had an interest in over 93,000 net acres of oil and gas leases, primarily located in the Rocky Mountains. During 2003, we produced 3.25 billion cubic feet of natural gas and 565,000 barrels of oil and natural gas liquids.

Definitions and Technical Terms

References in this report to Equity , the Company , we , our , or us refer to Equity Oil Company. We have used certain terms in this report that have specialized meanings, but which are commonly used in the oil and gas industry. Some of those terms are defined in the text in which they are used. We have provided below definitions of other specialized terms that we use in this report:

3-D seismic Geophysical data that depict subsurface strata in three dimensions. 3-D seismic data typically provide a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic data.

Bbl One stock tank barrel, or 42 U.S. gallons of liquid volume, used in this report in reference to oil and other liquid hydrocarbons.

Bcf One billion cubic feet of natural gas.

Boe Barrels of oil equivalent, determined using the ratio of six thousand cubic feet of natural gas to one barrel of oil.

Boepd Boe per day.

Bopd Barrels of oil per day.

BTU British thermal unit.

completion The installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Mcf One thousand cubic feet of natural gas.

Mcf/d One Mcf per day.

Mbbls Thousands of barrels of oil.

MMboe One million barrels of oil equivalent.

MMbtu One million British Thermal Units.

MMcf One million cubic feet of natural gas.

MMcf/d One MMcf per day.

PUD Proved undeveloped oil and gas reserves.

SEC PV10% The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated lease operating expense, production taxes and future development costs, using price and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

working interest The interest in an oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

Business Strategy

Our primary business objectives are to build shareholder value through consistent growth of our reserves and production and to increase our net asset value, cash flow and earnings per share. We have developed a number of long term strategies for achieving these business objectives, including:

We focus on operating efficiencies in order to minimize our operating costs and maximize our oil production. Most of our oil production, particularly in the Rocky Mountain area, comes from mature properties that have declining production volumes, and a number of our cost reduction programs are designed to reduce our operating costs while increasing the ultimate recovery of a higher percentage of the original oil in place in these mature properties.

We use modern techniques to increase our production from existing properties. These techniques include detailed geological studies (including 3-D seismic imaging), hydraulic fracturing, reserve stimulation techniques and water shutoff treatments.

We have an active drilling program and commit a portion of our budget to low- to medium-risk development drilling. Where appropriate, however, we employ focused exploration drilling and allocate some of our resources to higher-risk focused exploration that may provide us with a higher potential return on our investment.

We independently evaluate each project we undertake, whether development, exploration or exploitation, to ensure that our estimated rate of return for the project is commensurate with the associated risk. We also work with the other working interest owners in our producing properties to identify projects that will develop and exploit the productive capacities of our existing wells and fields. These projects include development drilling, production enhancement, operating cost reductions and other types of activities. Although our general practice is to participate in exploration projects on a 25% to 50% working interest basis, our participation varies with each prospect depending on a number of factors, including location and the attendant financial and technical risks.

We have historically purchased interests in properties with existing production. During the last five years, we have replaced a significant portion of our production by purchasing producing properties. These purchases have, in turn, produced additional developmental and enhancement projects, as well as opportunities for us to implement the operating efficiency procedures that we have developed.

Developments since December 31, 2002

During the year ended December 31, 2003, we achieved a number of business milestones. These milestones included:

We sold a portion of our Canadian properties. During the first quarter of 2003, we sold certain properties in Alberta and British Columbia, Canada, for $2.4 million in three separate transactions. We used the net after tax proceeds from these sales to reduce a portion of our long-term debt. Our remaining Canadian asset is a 50% non-operated working interest in the Cessford Field.

We drilled four development wells during 2003. We completed three gas wells in the Todhunters Lake Field of the Sacramento Basin in California. We also completed a development oil well confirming the successful Williston Basin exploration discovery.

We drilled one successful exploration well. We participated in the drilling of one successful exploration well in the Williston Basin of North Dakota.

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We enhanced our production capabilities. We increased production in our Torchlight Field in the Big Horn Basin through our polymer injection water shutoff treatment program.

We increased cash flow and book values per share and continued to record positive net income. We recorded positive net income for the fifth consecutive year in 2003. In addition, our cash flow from operations was $11.5 million for 2003, compared to $9.6 million in 2002. We increased our book value per outstanding share from $2.77 to $2.99.

Principal products and markets

In 2003, we had revenues from oil and gas sales of $27,461,759, compared to $23,374, 221 and $19,374,434 in 2002 and 2001, respectively. Approximately 93% of our revenues during 2003 were from our United States operations, compared to 95% for 2002 and 94% for 2001. During those same periods, we had net income of $2,115,123 (2003), $1,001,077 (2002) and $2,281,117 (2001). We had total assets of $76,706,535 at December 31, 2003, $76,800,356 at December 31, 2002, and $48,309,335 at December 31, 2001. For additional information regarding our financial operating results see Item 6, Selected Financial Data, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations, and our financial statements included elsewhere in this report.

During the last five years, more than 90% of our total revenues have come from the sale of crude oil and natural gas. Our remaining revenues have come from a number of other sources, including interest income on invested funds, and from sales of portions of our developed and undeveloped properties.

Most of our oil production occurs in Colorado, other Rocky Mountain states, and the Canadian province of Alberta. We sell our crude oil production under short-term contracts at current posted prices for each geographic area, less applicable quality adjustments, plus negotiated bonuses. The prices we receive for our oil are set by oil purchasers. The bulk of our natural gas production occurs in California and Wyoming. We sell our gas under contracts that are based upon the daily spot market or at index prices that change monthly. The contracts are subject to renegotiation on an annual basis. We have historically been able to sell all of our production and expect to be able to continue to do so in the future even though we compete with other companies with larger reserves in the same areas. See the section entitled Major Customers for additional information regarding pricing.

In order to finance our acquisition activities, our lending institution has required us to hedge a portion of our production as a way to manage our exposure to oil and gas price volatility. We place these hedging instruments with counterparties that we believe are minimal credit risks and that we believe are both competent and competitive market makers. The oil and gas reference prices upon which the price hedging instruments are based reflect various market indices that have a high degree of historical correlation with the actual prices we receive. When our current hedging contracts expire we will not be required by our lending institution to continue our hedging program.

As of December 31, 2003, we had commodity price hedges in place for 5,000 MMbtu, of natural gas per day under a costless collar in effect through April 30, 2004. The hedge has a floor of $3.00 per MMbtu and a ceiling of $4.43 per MMbtu.

Seasonality

Net gas sales prices have historically increased during the winter months. With our recent acquisition of gas properties in California, where changes in prices during the winter months are less dramatic than other areas of the country, the seasonal impact has been reduced. Therefore, the seasonal impact on our total gas sales is not significant.

Major Customers

We sell all of our produced oil and gas to unaffiliated pipeline companies, refining companies or crude oil trading companies. These companies may be the operators of the fields where the product is produced, owners of the pipelines which transport the products, or other third-party purchasers. Sales prices for our oil and gas are negotiated based on factors normally considered in the industry, such as index or spot prices for gas or the posted price of oil, price regulations (where applicable), distance from the well to the pipeline, estimated reserves, commodity qualities and prevailing supply conditions. We cannot control many of these factors.

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Sales to Teppco Crude Oil, L.P. accounted for 44%, 41% and 49% of our total oil and gas production revenue for the years 2003, 2002 and 2001, respectively. Sales to Calpine Producer Services, L.P. accounted for 36% and 33% of our total oil and gas production revenue for the years 2003 and 2002, respectively. In 2001, one other purchaser accounted for 12% of our total oil and gas production revenue. The entities referenced above each purchased more than 10% of our oil and gas production for the years indicated; however previous changes in purchasers have not had a material adverse effect on our business.

Competition

The oil and gas industry is highly competitive. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Our competitive position depends upon our geological, geophysical and engineering expertise, our financial resources, and our ability to select, acquire and develop proved reserves.

We believe the locations of our leasehold acreage, our exploration, drilling and production capabilities, the experience of our management and the experience of our industry partners generally allow us to compete effectively in our core operating areas. We compete, however, with a substantial number of major and independent oil and gas companies, many of which have larger technical staffs and greater financial and operational resources.

There is also intense competition in the oil and gas industry for certain types of equipment. Drilling rigs and other equipment necessary for drilling and completion of wells may be in short supply from time to time due to this type of competition.

Environmental Regulations

Our drilling activities in the United States are regulated by several federal and state governmental agencies, including the Environmental Protection Agency, Forest Service and Bureau of Land Management, as well as state oil and gas commissions and state wildlife agencies for those states in which we have operations. Our Canadian operations are subject to similar regulations. These regulations may change periodically and for a variety of political, economical and other reasons.

We are committed to conducting our operations in a manner that protects the health and safety of our employees, contractors, the environment and the public. Environmental, health and safety programs are integral parts of all of our business activities. Although these programs have a substantial impact upon the energy industry, they generally do not affect us to any greater or lesser extent than other companies who operate in our core geographic areas and in the domestic oil and gas industry, as a whole. We believe that compliance with environmental laws and regulations will not have a material adverse effect on our operations or financial condition. We cannot, however, give any assurances that changes in, or additions to, laws or regulations regarding the protection of the environment will not have such an impact in the future.

We maintain insurance coverage in amounts and for risks that we believe is customary in the industry. We are not aware of any environmental claims existing as of December 31, 2003 that would have a material adverse impact upon our financial position, results of operations, or liquidity.

Other Governmental Regulation

In the past, the federal government has regulated prices at which oil and natural gas could be sold. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act of 1989 removed all price controls affecting producing wellhead sales. While sales by producers of oil, natural gas and natural gas liquids can currently be made at uncontrolled market prices, the United States Congress could reenact price controls or other regulations regarding the sales price of those products at any time in the future.

Our natural gas sales are affected by regulations for intrastate and interstate transportation. In recent years, the Federal Energy Regulatory Commission has issued a series of orders designed to increase competition. These orders removed the transportation barriers to market access and have had a significant impact on gas markets in the United States. The regulations and orders have also fostered the development of a large spot market for gas and increased competition for gas markets. As a result of these regulations and orders, producers can access gas markets directly, but face increased competition. We believe these changes have generally improved our access to transportation and have enhanced the marketability of our natural gas production.

Our oil and natural gas operations are also regulated by administrative agencies under statutory provisions of the states where our operations are conducted and by certain agencies of the federal government for operations on federal oil and gas leases. All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for, and production of, crude oil and natural gas. These statues include statutes regulating the size of drilling and spacing units and the number of wells which can be drilled in an area, and the unitization or pooling of natural gas properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, typically prohibit venting or flaring of natural gas, and impose certain requirements regarding the apportionment of production from fields and individual wells. These regulations may limit the amount of oil and natural gas we can produce from our wells and limit the number of wells or locations at which we can drill. State commissions also establish rules for reclamation of sites, plugging bonds, reporting and other matters.

The oil and natural gas industry in Canada is also subject to extensive controls and regulations imposed by various levels of the government. Canadian federal authorities do not regulate the price of oil and gas in export trade, but rely on market forces to establish those prices. Canada does, however, have legislation that regulates the quantities of oil and natural gas which may be removed from the provinces and exported from Canada. We do not expect any of these controls and regulations to affect us in a manner significantly different than it affects other oil and natural gas companies that have comparable-sized operations.

The province of Alberta has legislation and regulations which govern land tenure, royalties, and production rates. The royalty regime in Canadian provinces is a significant factor in our profitability. Crown royalties are generally determined by government regulations and are typically calculated as a percentage of the value of production.

Operational Hazards

The oil and gas industry is subject to a variety of operating risks, including risks relating to fire, explosion, blowouts, pipe failures, casing collapses, abnormally pressurized formations and environmental hazards relating to oil spills, gas leaks, ruptures and discharges of toxic substances. If any of these events were to occur, we could suffer significant injuries to both life and property, and we could be subject to investigation, penalties and suspension of operations, as well as claims for damages. We maintain insurance against some, but not all, of these potential risks. We can give no assurance that any insurance that we obtain for these risks will be adequate to cover all potential losses or exposures for those types of liability, or that we can obtain any such insurance at commercially reasonable terms.

Employees

We currently have 28 full time employees.

Financial Information About Foreign Operations

We conduct a portion of our business operations in the Canadian province of Alberta. Financial information concerning these operations can be found in Footnotes 6 and 10 to the financial statements included as a part of this report. For financial reporting purposes, we do not allocate any general and administrative expenses to our Canadian operations, nor are they burdened with indirect exploration overhead expenses. We charge direct exploration expenses to the geographic area in which they occur. Because the majority of our exploration efforts occurs in the United States, we allocate only minimal exploration expenses to our Canadian operations. We do not believe there is a significant difference in the business risks of operating in the United States, as compared to operating in Canada.

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ITEM 2. Properties

Our principal properties consist of developed and undeveloped oil and gas leasehold interests. Our developed leases are comprised of properties with existing production, where lease terms continue as long as oil and/or gas is produced. Undeveloped leases include unproven acreage on both public and private lands. The leases have set terms and terminate at the time specified in the lease, unless oil and/or gas in commercial quantities are discovered prior to that time. Our undeveloped leaseholds at December 31, 2003 have remaining lives ranging from one to five years.

Our exploration, development and acquisition activities are focused in the Big Horn Basin (Wyoming), other Rocky Mountain states, the Sacramento Basin (California), and Canada.

We finance our business through cash flows from operations and borrowings under our credit facility. Under the terms of our credit facility, we are required to mortgage our core properties as security for the amounts we borrow. Set forth below is summary information as of and for the year ended December 31, 2003 concerning our proved reserve quantities in our major areas of operations:

	As of December 31, 2003 Proved Reserve Quantities (In 000 s)		
	Crude Oil-Bbls	Natural Gas-Mcf	Boe Total
Big Horn Basin	2,979	1,790	3,277
Other Rockies	5,959	10,965	7,611
Sacramento Basin		14,741	2,457
Canada	821	585	919
Other	185		185
Total	9,944	28,081	14,449

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Big Horn Basin

The Big Horn Basin of northwestern Wyoming has been a focus area for us since 1997. Our operations in the area are managed by our Cody, Wyoming office, which has 12 employees.

Our Big Horn Basin properties are typically long-lived high water cut oil fields which benefit from our expertise in lift optimization and polymer injection technology to reduce water production. We operate 95 wells in the basin, producing 948 Boepd. Our working interests in these wells range from 30% to 100%.

Our most significant asset in the Big Horn Basin is our 100% working interest in the Torchlight Field. During 2003, we continued our water shutoff treatment program in the field, successfully treating five wells. Approximately 45% of the field s current daily production of 310 Bopd is attributable to increased production from successful water shutoff treatments that we completed between 2001 and 2003. In addition, since we assumed operation of the field in January 2000, we have reduced water production by 12,500 barrels per day. We expect to perform six additional water shutoff treatments during 2004.

Other Rocky Mountain States

During July, 2003 we completed the #23-3 BR as the discovery well in our Roosevelt Creek Prospect in Golden Valley County, North Dakota. The #23-3 flowed 142 Bopd from the Nisku Formation at approximately 10,754 - 10,758 feet. We completed a stepout horizontal confirmation well, #11-10 Schieffer, pumping 117 Bopd, in December, 2003. We are a 25% working interest owner in both wells.

We have acquired 63 square miles of proprietary 3D seismic data in the Roosevelt Creek and adjacent Beaver Creek Prospect areas where these two wells were drilled, and have identified drilling opportunities targeting oil in the Bakken, Nisku and Red River Formations. Our year-end independent reserve evaluation from Ryder Scott Company, L.P. included sixteen proved undeveloped drilling locations in these Prospect areas.

We placed two development wells drilled at the end of 2002 on production during 2003 in our Siberia Ridge Field in Southwestern Wyoming. We completed the Anadarko #4-1 Siberia Ridge in the Almond Formation with an initial production rate of 370 Mcf/d, during March, 2003. We are a 50% working interest participant in this infill development well. We recorded initial gas sales from our Samson Resources #28-1 at a rate of 430 Mcf/d in January 2003. We are a 75% working interest owner in this well.

We also have a fee interest in 6,996 net acres of oil shale lands in the Piceance Basin of Colorado. We have not generated material revenues from these properties.

Sacramento Basin

Effective January 1, 2002, we purchased an operated working interest in 27 producing gas wells and associated leasehold primarily in the Todhunters Lake and Willow Slough Fields of Yolo County, California. We closed the acquisition on April 12, 2002 for a net purchase price of $30.0 million. The acquisition included proved developed producing reserves, proved developed behind pipe recompletion opportunities and several drilling opportunities. The acquired properties generated $15.5 million in gross operating profit through December 31, 2003.

During July 2003, we completed three development wells in the Todhunters Lake Field, where we maintain a 100% working interest. The #43-28 and #34-28 IOC were producing at a combined rate of 1.0 MMcf/d from the Upper Mokulmne Sandstone at year-end. Our third development well, the #33-28, was completed as a marginal producer in low permeability sands on the northwestern flank of the field. Initial reserve estimates for the #33-28 were 1.2 Bcf less than pre-drilling expectations. In addition, we dropped a fourth Upper Mokulmne drilling location from PUD classification, resulting in a cumulative reduction in reserves as a result of the 2003 development program of 2.0 Bcf. We also drilled an unsuccessful exploratory well, the #41-29 IOC, as a 75% working interest owner.

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We have maintained an active recompletion program since assuming operation of these properties. Approximately one-half of the current Yolo County production rate of 5.0 MMcf/d is attributable to our recompletion and development drilling program.

We have restricted gas production from the Yolo County assets since acquiring the property to reduce premature abandonment of individual gas zones from accelerated water encroachment or excessive sand production. The #1 Heidrick and McGinnis, which we completed in May, 2001, began producing substantial water volume in the first quarter of 2003, resulting in a reduction of 1.6 Bcf of proven reserves in our year-end 2003 reserve evaluation. During the fourth quarter of 2003, we lost the #12 IOC prematurely to excessive sand production and lost the #2-29 Hess located in the Willow Slough Field to water coning. Cumulatively, these two lost reservoirs were responsible for a reduction in our reserve estimates of 0.7 Bcf.

Our Yolo County assets continue to receive a premium price structure due to the proximity of the end user of the gas. The current net price that we receive is nearly double the wellhead netback at the time the transaction closed.

Our net gas production from the Yolo County properties during 2003 was 2.2 Bcf. Our independent reserve evaluation at year-end 2003 estimates net proven gas reserves of 13.5 Bcf for our Yolo County assets, with a net pretax present value (discounted at 10%) of $34.1 million.

Canada

During February and March 2003, we sold three packages of our Canadian oil and gas properties for approximately $2.4 million, resulting in a gain of approximately $1.2 million ($655,000 net of tax). Our revenue from these Canadian oil and gas properties was approximately $969,000 for 2002 and $1,216,000 for 2001. After the sales, our remaining Canadian asset is our 50% interest in the Cessford Field, which is located in southern Alberta.

Reserves

There are many uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of exploitation expenditures. The data in the following tables represent estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of hydrocarbons that cannot be measured exactly, and estimates of other engineers might differ materially from those shown below. The accuracy of any reserve estimate is also a function of the quality of available data and engineering and geological interpretation and judgment. Drilling, testing and production results after the date of the estimate may justify revisions. Accordingly, our reserve estimates may vary from the quantities of oil and natural gas that we ultimately recover.

Further, the future prices that we receive for production and costs may vary, perhaps significantly, from the prices and costs we assumed for purposes of the estimates set forth below. The present value shown should not be construed as the current market value of the reserves, and the 10% discount factor we used to calculate present value (which is mandated by the Securities and Exchange Commission rules) is not necessarily the most appropriate discount rate. Moreover, the present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

The following data for 2003 is based on an evaluation by Ryder Scott Company L.P. of our oil and gas properties as of December 31, 2003. The evaluation of our reserves for 2002 and 2001 was done by us and audited by Fred S. Reynolds & Associates. The PV-10 values (future estimated net pretax revenues discounted at 10%) shown in the following table are not intended to represent the current market value of our estimated net oil and gas reserves. Neither prices nor operating costs have been escalated in this evaluation.

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The following table sets forth summary information with respect to the estimates of our net reserves for each of the years in the three-year period ended December 31, 2003:

	As of December 31,		
	2003	**2002**	**2001**
Reserve Data:			
Oil Mbbls	9,944	10,550	8,581
Gas - MMcf	28,081	36,588	16,579
Mboe	14,624	16,648	11,344
PV-10 value, (in 000 s)	$ 93,969	$ 105,271	$ 28,911
Proved Developed Reserves	79%	86%	92%
Life (years)[a]	13.2	12.5	12.8

[a] Year end reserves divided by annual production

The present value of estimated future net revenues of our reserves was $94 million as of December 31, 2003. This present value is based on a benchmark of prices in effect at that date of $32.55 per barrel of oil and $5.97 per Mcf of gas. Both of these prices were then adjusted for transportation and basis differentials for each property, resulting in net average prices of $29.26 per barrel of oil and $5.36 per Mcf of natural gas at year-end. These prices were 8% and 31% higher, respectively, than prices in effect at the end of 2002.

Proved developed reserves are proved reserves that are expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells where a relatively major expenditure is required to establish production.

We have not filed any estimates of reserves with or included the information contained in this section in any report to any federal agency other than the Securities and Exchange Commission during 2003.

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Production

The following table sets forth our production, average sales prices and average lifting costs by geographic area for 2003, 2002 and 2001:

	2003 Oil (Bbls)	2002 Oil (Bbls)	2001 Oil (Bbls)	2003 Gas (MMcf)	2002 Gas (MMcf)	2001 Gas (MMcf)
Production						
Colorado	233,654	245,478	265,145	38	44	58
Texas	12,221	12,802	13,650			
Montana	21,039	19,475	24,726	30	32	32
Utah	34,405	30,667	34,359			
Wyoming	165,962	193,233	170,282	619	517	551
North Dakota	26,663	33,258	45,445	11	16	28
California				2,473	3,331	539
Total U.S.	493,944	534,913	553,607	3,171	3,940	1,208
Alberta	71,089	88,704	74,596	83	255	281
B.C.		10,237	9,010		3	7
Total Canada	71,089	98,941	83,606	83	258	288
Grand Total	565,033	633,854	637,213	3,254	4,198	1,496
Average Price including the effect of hedging costs						
U.S.	$ 26.97	$ 22.26	$ 22.65	$ 3.73	$ 2.51	$ 4.89
Canada	$ 20.50	$ 20.35	$ 16.43	$ 3.59	$ 2.10	$ 3.13
Total	$ 26.15	$ 21.97	$ 21.84	$ 3.73	$ 2.48	$ 4.55
Average Price excluding the effect of the hedging costs						
U.S.	$ 28.38	$ 22.75	$ 22.65	$ 4.38	$ 2.52	$ 4.89
Canada	$ 20.50	$ 20.35	$ 16.43	$ 3.59	$ 2.10	$ 3.13
Total	$ 27.39	$ 22.38	$ 21.84	$ 4.36	$ 2.49	$ 4.55
Lifting Costs						
U.S.	$ 8.83	$ 7.93	$ 7.32	$ 1.22	$ .89	$ 1.58
Canada	$ 4.13	$ 6.77	$ 5.55	$ .72	$ .61	$ 1.04
Total	$ 8.24	$ 7.75	$ 7.08	$ 1.21	$ .88	$ 1.47

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Productive Wells and Acreage

The location and quantity of our productive wells and acreage as of December 31, 2003 were as follows:

	Gross	Net
Productive Wells:		
Oil:		
United States	618	88.09
Canada	27	13.50
Gas:		
United States	97	40.54
Canada	0	.00
Total Productive Wells	742	142.13
Developed Acreage		
United States	113,222	14,663
Canada	2,160	1,080
Total Developed Acreage	115,382	15,743

Undeveloped Leasehold Acreage

The following table sets forth our undeveloped oil and gas leasehold acreage as of December 31, 2003 by geographic area:

Area	Gross Acreage	Net Acreage
Colorado	20,986	7,127
Texas	1,197	252
Montana	18,108	4,959
Utah	39,803	14,283
Wyoming	38,661	26,152
California	14,463	5,935
North Dakota	47,951	17,804
Total U.S.	181,169	76,512
Alberta	4,000	1,005
Total Canada	4,000	1,005

Grand Total	185,169	77,517

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Drilling Activity

During 2003, we participated in the drilling of 7 gross wells. Of these, 5 were completed as producing oil and gas wells and 2 were plugged and abandoned as dry holes.

	Status	2003	2002	2001
Gross exploratory wells drilled:				
United States	Productive	1	3	
	Dry	2	2	4
Gross development wells drilled:				
United States	Productive	4	3	6
	Dry			1
Canada	Productive			6

	Status	2003	2002	2001
Net exploratory wells drilled:				
United States	Productive	.25	.62	
	Dry	1.00	.73	1.49
Net development wells drilled:				
United States	Productive	3.25	1.75	3.66
	Dry			.55
Canada	Productive			3.00

Symskaya Exploration

During 2003 our 1.1 million acre license to explore for, develop and produce hydrocarbons in the Yenisysk District of the Krasnoyarsk Krai in Russia was canceled. Costs incurred in connection with this prospect in 2003 were related to closing down all operations and interests in Russia.

Delivery Commitments

We are not obligated to provide any fixed or determinable quantities of oil or gas in the future under any existing contracts or agreements.

ITEM 3. Legal Proceedings

We do not have any material threatened or actual legal proceedings.

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

We did not submit any items during the fourth quarter of the fiscal year covered by this annual report to a vote of our security holders, through the solicitation of proxies or otherwise.

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PART II

ITEM 5. Market for the Company s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is traded on the over-the-counter market and quoted over the NASDAQ National Market System under the symbol EQTY. The range of high and low sales prices for our common stock for the quarterly periods in 2003 and 2002, as reported by Nasdaq are set forth below:

Quarter	High	Low
2003 - 4th	$ 4.19	$ 3.11
3rd	$ 4.15	$ 2.07
2nd	$ 3.00	$ 2.08
1st	$ 2.51	$ 1.95
2002 - 4th	$ 2.34	$ 1.72
3rd	$ 2.60	$ 1.51
2nd	$ 2.50	$ 1.89
1st	$ 2.14	$ 1.52

As of February 11, 2004, as shown on the most recent proxy certified listing from our transfer agent, the number of record holders of our common stock was 1,074. Our management believes, after inquiry, that the number of beneficial owners of our common stock is in excess of 4,000.

We have sold no unregistered equity securities, nor have we repurchased any of our outstanding equity securities, during the period covered by this report.

We did not pay any dividends during the year. Currently, the payment of dividends is not allowed under the provisions of our credit facility without obtaining a waiver from the lender. Payment of any future dividends will be at the discretion of our board of directors after taking into account many factors, including our financial condition, operating results, current and anticipated cash needs and plans for expansion.

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ITEM 6. Selected Financial Data

The following table sets forth selected financial data from our operations as of the dates and for the periods indicated. The financial data for each of the five years ended December 31, 2003 are derived from financial statements which have been audited by PricewaterhouseCoopers LLP, our independent public accountants. The following data should be read in conjunction with material contained in the section below entitled Management s Discussion and Analysis of Financial Condition and Results of Operations, which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with our financial statements included elsewhere in this report. For information on our payment of dividends, see Item 5, Market for the Company s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

	Years Ended December 31,				
	2003	2002	2001	2000	1999
	(dollars in millions except per share data)				
Income Statement Information					
Revenues:					
Oil and Gas Sales	$ 30.2	$ 23.7	$ 19.4	$ 23.0	$ 14.7
Loss on oil and gas hedging activities	(2.8)	(0.3)			
Interest income and other	0.4	0.3	0.3	1.1	0.3
Total revenues	$ 27.8	$ 23.7	$ 19.7	$ 24.1	$ 15.0
Costs and expenses:					
Lease operating	8.6	8.3	6.4	6.4	5.8
Depreciation, depletion and amortization	8.1	7.7	4.2	3.6	3.8
Impairment of proven oil and gas properties		0.1	0.4	0.4	0.3
Exploration	0.6	1.3	1.5	2.3	0.8
General and administrative overhead	3.1	2.4	2.4	1.9	1.7
Exploration and production overhead	1.6	1.4	1.4	1.2	1.0
Asset retirement obligations accretion	0.2				
Interest expense	1.1	1.2	0.4	1.1	1.2
Total costs and expenses	23.3	22.4	16.7	16.9	14.6
Income from continuing operations before income taxes	4.5	1.3	3.0	7.2	0.4
Income tax expense	2.1	0.7	1.2	2.4	0.2
Income from continuing operations	2.4	0.6	1.8	4.8	0.2
Income from discontinued operations	0.8	0.4	0.5	0.4	0.2
Income before cumulative effect of accounting change	3.2	1.0	2.3	5.2	0.4
Cumulative effect of accounting change, net of taxes	(1.1)				
Net income	2.1	1.0	2.3	5.2	0.4
Basic per common share information					
Income from continuing operations	$ 0.21	$ 0.05	$ 0.14	$ 0.37	$ 0.02
Income from discontinued operations	0.06	0.03	0.04	0.04	0.01
Cumulative effect of accounting change	(0.09)				

Basic net income per common share	$ 0.18	$ 0.08	$ 0.18	$ 0.41	$ 0.03
Diluted per common share information					
Income from continuing operations	$ 0.20	$ 0.05	$ 0.14	$ 0.36	$ 0.02
Income from discontinued operations	0.06	0.03	0.04	0.04	0.01
Cumulative effect of accounting change	(0.09)				
Diluted net income per common share	$ 0.17	$ 0.08	$ 0.18	$ 0.40	$ 0.03
Other Financial Information					
Net cash provided by operating activities	$ 11.5	$ 9.6	$ 7.6	$ 10.3	$ 4.4
Capital expenditures	4.7	35.9	5.9	3.1	2.4
Balance Sheet Information					
Total assets	$ 76.7	$ 76.8	$ 48.3	$ 47.8	$ 46.1
Long-term debt	29.0	34.5	5.5	8.5	15.0
Stockholders equity	$ 36.0	$ 33.2	$ 34.9	$ 32.6	$ 27.4

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ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations

GENERAL

Our profitability from operations in any particular reporting period will be directly related to the average realized prices of oil and gas sold, the volume of oil and gas produced and the results of acquisition, development and exploration activities. The average realized prices of oil and gas fluctuates from period to period due to market conditions and the results of our hedging activities. The aggregate amount of oil and gas that we produce may fluctuate based on our development and exploitation of oil and gas reserves and other factors. We expect production rates, value-based production taxes, labor and maintenance expenses to be the principal influences on operating costs. Accordingly, our results of operations may fluctuate from period to period.

We use the successful efforts method of accounting for oil and natural gas activities. Under this method, only the cost of successful efforts are capitalized as oil and gas properties. Costs of exploratory dry holes, geological and geophysical costs, delay rentals, general and administrative costs associated with our exploration efforts and other property carrying costs are expensed as incurred.

The prices we received from the sale of oil and natural gas during 2003 were higher than the prices we received during 2002. The prices received for our oil vary from NYMEX prices based on the location and quality of the crude oil. The prices we receive for our natural gas are based upon posted prices in the area where the gas is produced, reduced by transportation charges and processing fees. Transportation costs are comprised of costs paid to a carrier to deliver oil or natural gas to a specified delivery point.

Oil and natural gas production costs consist of lease operating expense and production taxes. Lease operating expense consists of pumpers salaries, utilities, maintenance and other costs necessary to operate our producing properties. Production taxes are assessed by applicable taxing authorities as a percentage of revenues or reserve value.

Exploration expense consists of geological and geophysical costs, delay rentals and costs of unsuccessful exploratory wells. Delay rentals and some overhead costs are typically fixed in nature in the short term. However, other exploration costs are generally discretionary and exploration activity levels are determined by a number of factors, including oil and natural gas prices, availability of funds, quantity and character of investment projects, availability of service providers and competition. Production and exploration overhead expense consists of exploration staff overhead costs, technical and production office expenses and production staff overhead costs that are not directly billed to our producing properties.

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Depletion, depreciation and amortization (DD&A) of capitalized costs of producing oil and natural gas properties is computed using the unit-of-production method based on proved reserves. For purposes of computing DD&A, proved reserves are redetermined as of the end of each year. Because the economic life of each producing well depends upon assumed prices, fluctuations in oil and gas prices impact the level of proved reserves. Higher prices generally have the effect of increasing reserves, which reduces DD&A, while lower prices generally have the effect of decreasing reserves, which increases DD&A expense.

CRITICAL ACCOUNTING POLICIES

A summary of our significant accounting policies is included in Footnote 1 to our financial statements. We believe the application of these accounting policies on a consistent basis enables us to provide timely and reliable financial information about our earnings results, financial condition and cash flows.

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires management to make judgments, estimates and assumptions regarding uncertainties that affect the reported amounts presented and disclosed in the financial statements. Our management reviews these estimates and assumptions based on historical experience, changes in business conditions and other relevant factors that they believe to be reasonable under the circumstances. In any given reporting period, actual results could differ from the estimates and assumptions used in preparing our financial statements.

Critical accounting policies are those policies that may have a material impact on our financial statements and also require our management to exercise significant judgment due to a high degree of uncertainty at the time the estimate is made. Our senior management has discussed the development and selection of our accounting policies, related accounting estimates and the disclosures set forth below with the Audit Committee of our Board of Directors. We believe our critical accounting policies include those addressing the recoverability and useful lives of assets, oil and gas reserve estimates and income taxes.

The computation of our income tax expense requires the interpretation of complex tax laws and regulations in many taxing jurisdictions in the United States and Canada as well as any possible assessments due to audits that may be performed by numerous taxing authorities. Actual income tax expense can differ significantly from management s calculated amounts.

OIL AND GAS RESERVES

Estimates of reserve quantities and related future net cash flows are calculated using unescalated year-end oil and gas prices and operating costs, and may be subject to substantial fluctuations based on the prices in effect at the end of each year. The reserves for 2003 were prepared by Ryder Scott, L.P. For 2002 and 2001, the reserves were prepared by us and audited by Fred S. Reynolds and Associates. The following table sets forth a comparison of year-end reserves, the weighted average prices used in calculating estimated reserve quantities at the end of 2003, 2002 and 2001 (quantities in thousands, except for pricing and per barrel of oil equivalent amounts):

	Year-end proved reserves	Year-end prices

	Oil (Mbbls)	Gas (MMcf)	Boe	Oil	Gas
12/31/03	9,944	28,081	14,624	$ 29.26	$ 5.36
12/31/02	10,549	36,588	16,648	$ 27.01	$ 4.09
12/31/01	8,581	16,579	11,344	$ 16.03	$ 2.15

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IMPAIRMENT OF PROVED OIL AND GAS PROPERTIES

We assess our proved properties on a field-by-field basis for impairment, in accordance with the provisions of Statement of Financial Accounting Standards, or SFAS, No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, whenever events or circumstances indicate that the capitalized cost of oil and natural gas properties may not be recoverable. When making such assessments, we compare the expected undiscounted future net revenues on a field-by-field basis with the related net capitalized costs at the end of each period. When the net capitalized costs exceed the undiscounted future net revenues, the cost of the property is written down to fair value, which is determined using discounted future net revenues. Reserve categories used in the impairment analysis consider all categories of proven reserves and probable and possible reserves, which are risk-adjusted based on our drilling plans and history of successfully developing those types of reserves.

No impairment charges were recorded in 2003. During 2002, we recorded an impairment of oil and gas properties charge of $53,990 associated with a certain field that experienced increased operating costs, declining production, reduced prospectivity due to unsuccessful drilling, and other technical problems that reduced their economic reserves. During 2001, we recorded impairment charges of $404,395.

RESULTS OF OPERATIONS

Comparison of 2003 with 2002

Oil and gas production and sales. Higher crude oil and natural gas prices in 2003 offset payments made pursuant to our hedging arrangements, and lower production volumes from our properties. This allowed us to record oil and gas sales from continuing operations of $27,461,759 in 2003 compared to $23,374,221 in 2002, representing a 17% increase.

We periodically enter into hedging activities for a portion of our oil and natural gas production as a requirement of our bank credit facility, to support our received oil and natural gas prices at targeted levels and to manage our exposure to price fluctuations. During 2003, we had commodity price hedges in place for 1,100 barrels of oil a day until April 30th and 6,000 MMbtu of natural gas per day for the entire year under costless collars. The settlement price of each of the contracts during the year resulted in the Company making payments to the counterparty of approximately $2.8 million. These payments are netted against oil and gas revenues. During 2002 payments of approximately $305,000 were made. As of January 1, 2004, we had 5,000 MMbtu of natural gas per day through April 30, 2004 subject to hedging arrangements under costless collars. During 2003, approximately $1.6 million (net of income taxes, $1.0 million) was reclassified from accumulated other comprehensive income to net income.

Average 2003 received commodity prices were much higher than the prior year received price ($26.15 in 2003 compared to $21.97 in 2002 for oil and $3.73 in 2003 compared to $2.48 in 2002 for natural gas). These average received prices take into consideration the hedging payments discussed above and any deductions for product quality and transportation charges. Excluding the effects of hedging, the average received prices for 2003 were $27.39 for oil and $4.36 for natural gas compared to $22.38 and $2.99, respectively, in 2002.

Oil production declined from 634,000 barrels in 2002 to 565,000 barrels in 2003. Approximately 26,000 barrels of this decline is attributed to the Canadian properties that we sold in 2003. The balance of the oil production decline is attributable to normal production declines as our properties mature. Gas production in 2003 of 3,254,000 Mcf also declined from 4,198,000 Mcf in 2002. The decline in gas production is attributable to earlier than anticipated depletion of some of the Sacramento Basin gas properties acquired in 2002 and to our change in operating philosophy whereby production on other properties was restrained to prevent premature depletion of the reservoir.

Other income. Included in 2003 other income is approximately $50,000 in non-recurring sales of proprietary 3-D seismic data. No such sales took place in 2002.

Lease operating costs. Lease operating costs in 2003 increased by approximately 3% or $260,633. The increase is primarily attributable to higher value based production taxes on the higher revenue received.

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Depreciation, depletion and amortization (DD&A). DD&A increased approximately 6% or 439,011 from 2002 to 2003. The increase is the result of a reduction in year-end reserves on properties which depleted earlier than originally projected.

Impairment of proved oil and gas properties. As discussed previously, included in the statement of operations for 2003 and 2002 are non-cash charges for the impairment of proved oil and gas properties in the amount of $0 and $53,990, respectively.

3-D seismic and exploration expenses. We participated in one 3-D seismic survey during 2002. The survey was a 24 square mile survey adjacent to our Beaver Creek Prospect in North Dakota. Our share of the cost, approximately $215,000, was charged to expense during the year. During 2003 we did not participate in any new surveys. Approximately $25,000 of costs associated with the 2002 surveys were incurred during 2003.

Lower exploration costs in 2003 reflected lower dry hole costs incurred during the year. We drilled two dry holes in each year. The majority of the 2002 dry hole expense was associated with one higher cost well in which we had a 47.5% working interest. The two dry holes in 2003 were lower cost than the dry holes in 2002. Dry hole costs in 2002 were approximately $471,000 higher than the amount recorded in 2003.

General and administrative expenses. General and administrative expenses increased approximately $687,000, or 29%, from 2002. The increase is attributable to charges incurred in connection with the process of exploring strategic alternatives. These costs include legal, outside consultants, travel and other process related charges. Insurance costs, shareholder expenses, employee benefits and fees associated with the Company s credit facility also contributed to the increase.

Production and exploration overhead expenses. Production and exploration overhead expenses are salaries and benefits for employees who oversee our production and exploration activities and costs related to maintaining our technical office in Denver, Colorado and our operations office in Cody, Wyoming. These costs increased from $1.4 million to $1.6 million in 2003, representing approximately a 14% increase. This increase is primarily due to higher employee benefit costs in 2003.

Interest and income taxes. During the year we repaid $5.5 million of principal on our credit facility. Lower interest costs in 2003 reflect the lower balances outstanding under the credit facility.

Income tax expense for both periods reflects the results of operations, as well as the utilization of various credits and other tax attributes. Details concerning the components of the tax provision can be found in Footnote 4 to our financial statements.

Discontinued operations. During February and March 2003, we sold three packages of Canadian oil and gas properties for approximately $2.4 million, resulting in a gain of approximately $1.2 million ($655,168 net of tax). In accordance with the provisions of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets , the results of operations and gain on sale of these properties have been reflected as discontinued operations. Revenue from these Canadian oil and gas properties was approximately $150,000 for 2003, $969,000 for 2002 and $1,216,000 for 2001. After the sales, our remaining Canadian asset is our 50% interest in the Cessford Field located in southern Alberta.

Other comprehensive income (loss). Other comprehensive income (loss) for the period reflects the change in the fair value of our commodity hedges, net of income taxes, that were in place at December 31, 2003. The fair value is computed by the counterparty using a financial modeling technique including a type of Black-Scholes method. The counterparty valued the hedges at December 31, 2003 at ($969,025) as compared to ($1,917,968) at December 31, 2002. These amounts are reflected as a liability in the balance sheet as fair value of financial instruments. The tax effected amounts of the change, ($598,132), is reported in other comprehensive income for 2003. We do not intend to terminate our current commodity hedges prior to their expiration date.

Change in Accounting. In August 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, Accounting for Asset Retirement Obligations. SFAS 143 was effective for the Company beginning January

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1, 2003. The most significant impact of this standard on the Company was a change in the method of accruing for site restoration costs associated with its oil and gas properties. Under SFAS 143, the fair value of asset retirement obligations is recorded as a liability when incurred, which is typically at the time the assets are placed in service. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities are accreted for the change in their present value and the initial capitalized costs are depreciated over the useful lives of the related assets.

We used an expected cash flow approach to estimate our asset retirement obligations under SFAS 143. Upon adoption at January 1, 2003, we recorded a retirement obligation of $3,147,061, an increase in property and equipment cost of $1,997,619, an increase in accumulated depreciation, depletion and amortization of $535,255 and a cumulative effect of accounting change, net of benefit from taxes, of $1,061,865.

Comparison of 2002 with 2001

Oil and gas production and sales. Gas volumes from the Sacramento Basin gas properties acquired in 2002 offset slightly lower oil volumes and lower natural gas prices as compared to 2001. This allowed us to record oil and gas sales of $23,374,221 in 2002, compared to $19,374,434 in 2001, a 21% increase. Gas revenues from the assets acquired in 2002 were approximately $7.9 million.

We periodically enter into hedging activities for a portion of our oil and natural gas production as a requirement of our bank credit facility, to support our received oil and natural gas price at targeted levels and to manage our exposure to price fluctuations. Starting in May 2002 we had commodity price hedges in place for 1,100 barrels of oil a day and 8,000 MMbtu of natural gas per day under costless collars. The settlement price of each of the contracts during the year resulted in our making payments to the counterparty of approximately $305,000. These payments are netted against oil and gas revenues. No such payments were made in 2001, as we had no volumes of oil or natural gas subject to hedging agreements.

Year-end 2002 received commodity prices were much higher than the prior year-end ($27.01 in 2002, compared to $16.03 in 2001 for oil and $4.09 in 2002, compared to $2.15 in 2001 for natural gas). However, average oil prices received for the full year 2002 were only slightly higher compared to the prior year. The average 2001 price received was $21.84 per barrel. After taking into consideration the hedging costs discussed above, the average oil price received in 2002 was $21.97 per barrel.

Average received gas prices were down sharply for 2002 when compared to 2001. After taking into consideration the hedging costs discussed above, the average gas price received in 2002 was $2.48 per Mcf compared to $4.55 per Mcf in 2001, or a 45% decrease.

Oil production remained relatively constant from 637,000 barrels in 2001 to 634,000 barrels in 2002. Gas production in 2002 was substantially higher in 2002 when compared to 2001, 4,198,000 Mcf compared to 1,496,000 Mcf in 2001. The oil production decline is attributable to normal production declines as our properties mature. The increase in gas production is attributable to the acquisition of the Sacramento Basin gas properties during the year. Production from the acquired properties was approximately 3.0 Bcf of gas.

Other income. Included in 2001 other income was $85,000 in non-recurring property sales recognized in the first quarter of the year. In 2002 these non-recurring property sales were minimal.

Lease operating costs. Lease operating costs in 2002 increased by approximately 28%, or about $1.87 million. Costs associated with the Sacramento Basin acquired gas properties accounted for approximately $1.0 million of the increase. The additional increase results from an adjustment in the fourth quarter of 2001 to reverse the accrual of $888,000 of prior years production taxes and other operating costs.

Depreciation, depletion and amortization (DD&A). DD&A per unit charges increased 22%, from $4.73 per Boe in 2001 to $5.75 per Boe in 2002. This increase is primarily the result of DD&A attributable to the acquired gas properties. The acquired gas properties have a shorter life than our other assets, thus DD&A on a per unit basis increased. DD&A charges attributable to the acquired assets was approximately $3.8 million.

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Impairment of proved oil and gas properties. As discussed previously, included in the statement of operations for 2002 and 2001 are non-cash charges for the impairment of proved oil and gas properties in the amount of $53,990 and $404,395, respectively.

3-D seismic and exploration expenses. We participated in one new 3-D seismic survey during 2002. The survey was a 24 square mile survey adjacent to our Beaver Creek Prospect in North Dakota. Our share of the cost, approximately $215,000, was charged to expense during the year. During 2001, we participated in two surveys with higher working interests, resulting in an expense of approximately $698,000.

Higher exploration costs in 2002 reflected higher dry hole costs incurred during the year. We drilled two dry holes in 2002 compared to five in 2001. The majority of the 2002 dry hole expense was associated with one well in which we had a 47.5% working interest. The working interest percentages for all of the dry holes in 2001 were much lower than 47.5%. Dry hole costs in 2002 were approximately $315,000 higher than the amount recorded in 2001.

General and administrative expenses. General and administrative expenses in 2002 were relatively unchanged from the prior year. Costs incurred in both 2002 and 2001 were approximately $2.4 million. Lower compensation related costs and other administrative costs in 2002 were offset by higher insurance expense, shareholder costs and costs associated with the pursuit of acquisition and divestiture opportunities during the year.

Production and exploration overhead expenses. Production and exploration overhead expenses are salaries and benefits for employees who oversee our production and exploration activities and costs related to maintaining our technical office in Denver, Colorado and our operations office in Cody, Wyoming. These costs were only slightly lower in 2002 when compared to 2001, $1.42 million compared to $1.44 million.

Interest and income taxes. Higher interest costs in 2002 reflect higher balances outstanding under our credit facility. The increase in the amount outstanding resulted from our 2002 property acquisition. The acquisition was paid for through borrowing approximately $31.5 million dollars during the second quarter of 2002.

Income tax expense for both periods reflects the results of operations, as well as the utilization of various credits and other tax attributes. Details concerning the components of the tax provision can be found in Footnote 4 to our financial statements.

Other comprehensive loss. Other comprehensive loss for the period reflects the change in fair value of our commodity hedges, net of income taxes, that were in place at December 31, 2002. The fair value is computed by the counterparty using a financial modeling technique including a type of Black-Scholes method. The counterparty valued the hedges at December 31, 2002 at ($1,917,988). This amount is included as a liability in the balance sheet as fair value of financial instruments and the tax effected amount, ($1,208,908), is reported in accumulated other comprehensive income for 2002. We do not intend to terminate our current commodity hedges prior to their expiration date.

LIQUIDITY AND CAPITAL RESOURCES

During 2003, we paid $5.5 million in principal on our credit facility, reducing the year-end amount outstanding to $29 million. We believe the cash flow from our properties will support the amount of debt outstanding and provide cash flow that will give us opportunities to continue to grow our asset value.

Our cash balances increased by 273% from the amount at December 31, 2002. Our current assets to current liabilities ratio increased to 3.59 to 1 at December 31, 2003 compared to 1.63 to 1 at the end of 2002. This increase is due primarily to the increase in cash at year-end. In anticipation of costs associated with the possible outcome of the strategic alternatives evaluation process, cash has been retained rather than paying down our credit facility.

Capital expenditures decreased 87% over 2002 levels, to approximately $4.7 million. The 2002 capital expenditures included $30.7 million for the properties acquired during the year.

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Our $75 million revolving credit facility with Bank One Texas, N.A. was secured by placing customary liens on the majority of the Company s properties in 2002. The facility had a current borrowing base commitment of $36 million at December 31, 2003. The facility has a LIBOR or a prime interest rate option; the weighted average interest rate on debt outstanding at December 31, 2003 was 3.40%.

The borrowing base commitment under our credit facility is subject to a redetermination as of April 1 and October 1 of each year, with estimated future oil and gas prices used in the evaluation determined by the lender. As of December 31, 2003, we had $7,000,000 of remaining availability on the facility. We are in compliance with all facility covenants.

Cash flow from operating activities of $11.5 million was 21% higher than the amount recorded during 2002. Increased oil and gas revenues was the primary driver for the increase.

The decrease in accounts payable in 2003 reflected less operational activity at the end of the year when compared to year-end 2002. Income taxes receivable decreased due to refunds that were received as a result of the tax net operating loss incurred in prior years.

We believe that our capital resources from existing cash balances, cash flow from operating activities, and funds available under our credit facility are adequate to meet the requirements of our business. However, future cash flows are subject to a number of variables, including the level of production and oil and natural gas prices. We cannot assure that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures or that increased capital expenditures will not be undertaken. We believe we have adequate liquidity to maintain our operations as they currently exist.

Contractual Obligations and Contingent Liabilities and Commitments.

We have no significant off-balance sheet transactions or similar instruments and we are not a guarantor of any other entities debt or other financial obligations.

The following table sets forth payments due by period for contractual obligations as of December 31, 2003:

	Total	0-3 Years
Revolving credit facility	$ 29,000,000	$ 29,000,000

RECENTLY ISSUED FINANCIAL ACCOUNTING STANDARDS

We have reviewed all recently issued, but not yet adopted accounting standards in order to determine their effects, if any, on the results of our operations or financial position. Based on that review, we believe that none of the recently issued pronouncements will have any significant effects on our future earnings or operations. Further discussion of recently issued accounting standards is found in Footnote 11 to our financial statements.

OFF BALANCE SHEET ARRANGEMENTS

None.

CAUTIONARY STATEMENTS

The preceding discussion and analysis should be read in conjunction with the consolidated financial statements, including the notes thereto, appearing elsewhere in this annual report on Form 10-K and in conjunction with the disclosures regarding forward looking statements set forth at the beginning of this report on Form 10-K.

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ITEM 7A Quantitative and Qualitative Disclosures about Market Risk

The primary objective of the following information is to provide historical and forward-looking quantitative and qualitative information about our potential exposure to market risks. We are exposed to various market risks, including, without limitation, fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position.

The following analysis presents the effect on earnings, cash flows and financial position as if the hypothetical changes in market risk factors occurred on December 31, 2003. Only the potential impacts of hypothetical assumptions are analyzed. This analysis does not consider other possible effects that could impact our business.

Interest rate risk. At December 31, 2003 the amount outstanding under our credit facility was $29.0 million. The weighted average interest rate for this facility was 3.40%. Assuming constant debt levels, the impact on earnings and cash flow for the next twelve month period from December 31, 2003 due to a one percent change in interest rates would be approximately $290,000 before taxes.

Commodity price risk. Oil and gas commodity markets are influenced by global as well as regional supply and demand. Worldwide political events can also impact commodity prices. Pricing for oil and natural gas production has been volatile and unpredictable for many years. In accordance with our current credit facility and to hedge exposure to changing commodity prices, we periodically enter into financial hedge contracts. Hedging may limit our exposure to adverse price changes; however hedging also limits the benefit of price increases and is subject to a number of risks, including the credit risk associated with the creditworthiness of the counterparty to the hedge. For additional information, see Footnote 1 to our financial statements.

During 2003, we made net payments to the counterparty of $2,765,247 under the hedge agreements in place. This amount is netted against our oil and gas revenue. We made payments of $305,425 in 2002.

We account for our hedging activity pursuant to SFAS 133, and accordingly we include the fair value of these hedges ($969,025 liability at December 31, 2003) on our balance sheet. Fair value represents the value computed by a counterparty using a financial modeling technique including a type of Black-Scholes method. As these contracts qualify and have been designated as cash flow hedges, we determine gains and losses on them resulting from market price changes at least quarterly and reflect them in accumulated other comprehensive income (loss) until the period in which the hedge is settled. At that time, the amount paid to or received from the counterparty is included in oil and gas revenue. We do not intend to terminate our current commodity hedges prior to their expiration date.

The hedges we had in place at December 31, 2003 were costless collars. We utilize collars that establish a price between a floor and ceiling to hedge natural gas prices. The table below sets forth our natural gas collars in place at December 31, 2003. We have no hedging arrangements for oil production at December 31, 2003.

	Per Day MMbtu	Average Floor MMbtu	Average Ceiling MMbtu	Fair Value of Financial Instrument Asset/ (Liability)

					(thousands)
Gas					
01/01/04	04/30/04	5,000	$ 3.00	$ 4.43	$ (969)

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ITEM 8. Financial Statements and Supplementary Data

Report of Independent Auditors

To the Stockholders and Board of

Directors of Equity Oil Company:

In our opinion, the financial statements as listed in Item 15(a) of this Form 10-K, present fairly, in all material respects, the financial position of Equity Oil Company (the Company) at December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America. 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 of these statements in accordance with auditing standards generally accepted in the United States of America, which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the financial statements, the Company changed the manner in which it accounts for asset retirement costs as of January 1, 2003.

PricewaterhouseCoopers LLP

/s/ PricewaterhouseCoopers LLP

Salt Lake City, UT
February 24, 2004

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EQUITY OIL COMPANY

BALANCE SHEETS

DECEMBER 31, 2003 AND 2002

	2003	2002
ASSETS		
Currents assets:		
Cash and cash equivalents	**$ 5,032,922**	$ 1,348,024
Accounts receivable	**3,945,189**	3,934,324
Operator advances	**494,293**	462,149
Federal, state and foreign income taxes receivable	**412,193**	1,054,927
Deferred income taxes	**59,300**	28,460
Other current assets	**117,707**	215,177
Total current assets	**10,061,604**	7,043,061
Property and equipment, at cost (successful efforts method):		
Unproved oil and gas properties	**4,893,684**	9,058,761
Proved oil and gas properties:		
Developed leaseholds	**35,280,714**	33,044,907
Intangible drilling costs	**72,033,090**	72,407,581
Equipment	**32,812,826**	31,332,238
Other property and equipment	**1,396,142**	1,331,490
	146,416,456	147,174,977
Less accumulated depreciation, depletion and amortization	**(80,270,860)**	(78,148,866)
	66,145,596	69,026,111
Other assets	**499,335**	731,184
Total assets	**$ 76,706,535**	$ 76,800,356
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable	**$ 1,408,238**	$ 2,157,291
Accrued liabilities	**319,821**	406,681
Federal, state and foreign income taxes payable	**105,393**	170,399
Fair value of derivative financial instruments	**969,025**	1,584,988
Total current liabilities	**2,802,477**	4,319,359
Asset retirement obligation	**3,242,383**	
Fair value of derivative financial instruments		333,000
Revolving credit facility	**29,000,000**	34,500,000
Deferred income taxes	**5,657,168**	4,398,319
Total liabilities	**40,702,028**	43,550,678
Commitments (Note 6)		

Stockholders equity:		
Common stock, $1 par value:		
Authorized: 25,000,000 shares		
Issued: 12,877,936 shares in 2003; and 12,856,661 shares in 2002	**12,877,936**	12,856,661
Paid in capital	**3,758,562**	3,738,263
Retained earnings	**21,970,229**	19,855,106
Accumulated other comprehensive loss	**(610,776)**	(1,208,908)
	37,995,951	35,241,122
Less treasury stock, 848,000 shares, at cost	**(1,991,444)**	(1,991,444)
	36,004,507	33,249,678
Total liabilities and stockholders equity	**$ 76,706,535**	$ 76,800,356

The accompanying notes are an integral part of the financial statements.

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EQUITY OIL COMPANY

STATEMENTS OF OPERATIONS

for the years ended December 31, 2003, 2002 and 2001

	2003	2002	2001
REVENUES AND OTHER INCOME			
Oil and gas sales	**$ 27,461,759**	$ 23,374,221	$ 19,374,434
Other income	**362,874**	309,282	344,378
	27,824,633	23,683,503	19,718,812
EXPENSES			
Leasehold operating costs	**8,592,380**	8,331,747	6,394,221
Depreciation, depletion and amortization	**8,113,644**	7,674,633	4,197,543
Impairment of proved oil and gas properties		53,990	404,395
Equity loss in Symskaya Exploration, Inc.	**56,559**	178,512	161,494
Leasehold abandonments	**32,342**	5,686	3,198
3-D Seismic	**25,025**	215,339	697,676
Exploration	**449,191**	908,379	594,336
General and administrative	**3,096,628**	2,409,304	2,440,241
Production and exploration overhead	**1,605,378**	1,424,116	1,444,458
Accretion expense	**219,220**		
Interest	**1,096,609**	1,176,375	431,108
	23,286,976	22,378,081	16,768,670
Income from continuing operations before income taxes	**4,537,657**	1,305,422	2,950,142
Provision for income taxes	**2,105,878**	658,246	1,197,543
Income from continuing operations	**2,431,779**	647,176	1,752,599
Discontinued operations (Note 1)			
Income from operations of properties sold, net of provision for income taxes of $52,812, $359,956 and $361,135, respectively	**90,041**	353,901	528,518
Gain on sale of properties, net of provision for income taxes of $453,940	**655,168**		
Income before cumulative effect of accounting change	**3,176,988**	1,001,077	2,281,117
Cumulative effect of change in accounting, net of benefit from income taxes of $622,832	**(1,061,865)**		
NET INCOME	**$ 2,115,123**	$ 1,001,077	$ 2,281,117
Proforma net income reflecting adoption of SFAS 143		$ 902,805	$ 2,191,617

The accompanying notes are an integral part of the financial statements.

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EQUITY OIL COMPANY

STATEMENTS OF OPERATIONS

for the years ended December 31, 2003, 2002 and 2001

Continued

	2003	2002	2001
Basic income per common share			
Income from continuing operations	$ .21	$ .05	$ .14
Income from discontinued operations	.06	.03	.04
Income before cumulative effect of accounting change	.27	.08	.18
Cumulative effect of change in accounting	(.09)		
NET INCOME	$ .18	$ .08	$ .18
Diluted income per common share			
Income from continuing operations	$ .20	$ .05	$ .14
Income from discontinued operations	.06	.03	.04
Income before cumulative effect of accounting change	.26	.08	.18
Cumulative effect of change in accounting	(.09)		
NET INCOME	$ .17	$ .08	$ .18
Proforma net income per share, reflecting adoption of SFAS 143			
Basic		$ .07	$ .17
Diluted		$ .07	$ 17
Weighted average shares outstanding			
Basic	12,014,000	12,300,094	12,680,068
Diluted	12,403,240	12,429,710	12,946,226

The accompanying notes are an integral part of the financial statements.

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EQUITY OIL COMPANY

STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

for the years ended December 31, 2003, 2002 and 2001

	2003	2002	2001
Net income	**$ 2,115,123**	$ 1,001,077	$ 2,281,117
Other comprehensive income (loss):			
Unrealized losses on financial instruments, net of benefit of income taxes of $235,138 in 2003 and $709,080 in 2002	**(400,886)**	(1,208,908)	
Reclassification adjustment for losses included in net income, net of benefit from income taxes of $585,970.	**999,018**		
Comprehensive income (loss)	**$ 2,713,255**	$ (207,831)	$ 2,281,117

The accompanying notes are an integral part of the financial statements.

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EQUITY OIL COMPANY

STATEMENT OF CHANGES IN STOCKHOLDERS EQUITY

for the years ended December 31, 2003, 2002 and 2001

	Common Stock		Paid in		Accumulated Other Comprehensive (Loss)/	Treasury Stock		Total Stockholders
	Shares	**Amount**	**Capital**	**Retained Earnings**	**Income**	**Shares**	**Amount**	**Equity**
Balance at January 1, 2001	12,819,212	$ 12,819,212	$ 3,719,865	$ 16,572,912	$	164,600	$ (528,302)	$ 32,583,687
Net income				2,281,117				2,281,117
Common stock issued on exercise of stock options	32,449	32,449	(19,347)					13,102
Income tax benefit from exercise of stock options			35,245					35,245
Balance at December 31, 2001	12,851,661	12,851,661	3,735,763	18,854,029		164,600	(528,302)	34,913,151
Net income				1,001,077				1,001,077
Common stock issued on exercise of stock options	5,000	5,000	2,500					7,500
Other comprehensive loss					(1,208,908)			(1,208,908)
Treasury stock purchase						683,400	(1,463,142)	(1,463,142)
Balance at December 31, 2002	12,856,661	12,856,661	3,738,263	19,855,106	(1,208,908)	848,000	(1,991,444)	33,249,678
Net income				2,115,123				2,115,123
Other comprehensive income					598,132			598,132
Common stock issued on exercise of stock options	21,275	21,275	9,300					30,575
Income tax benefit from exercise of stock options			10,999					10,999
Balance at December 31, 2003	12,877,936	$ 12,877,936	$ 3,758,562	$ 21,970,229	$ (610,776)	848,000	$ (1,991,444)	$ 36,004,507

The accompanying notes are an integral part of the financial statements.

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EQUITY OIL COMPANY

STATEMENTS OF CASH FLOWS

for the years ended December 31, 2003, 2002 and 2001

	2003	2002	2001
Cash flows from operating activities:			
Net income	**$ 2,115,123**	$ 1,001,077	$ 2,281,117
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**8,113,644**	7,674,633	4,197,543
Accretion expense	**219,220**		
Impairment of proved oil and gas properties		53,990	404,395
Property abandonments	**114,867**		
Equity loss in Symskaya Exploration, Inc.	**56,559**	178,512	161,494
(Gain) loss on sale of oil and gas properties	**(1,264,489)**	17,791	(81,824)
Cumulative effect of change in accounting	**1,061,865**		
Change in other assets	**(5,150)**	7,633	82,228
Deferred income tax expense	**1,500,010**	579,881	990,379
Increase (decrease) from changes in:			
Accounts receivable and operator advances	**(43,009)**	(1,466,477)	2,541,941
Other current assets	**97,470**	(183,383)	26,873
Accounts payable and accrued liabilities	**(835,916)**	833,492	(762,534)
Income taxes payable/receivable	**588,728**	862,164	(2,236,392)
Asset retirement obligation	**(175,754)**		
Net cash provided by operating activities	**11,543,168**	9,559,313	7,605,220
Cash flows from investing activities:			
Advances to Symskaya Exploration, Inc.	**(56,559)**	(178,512)	(161,494)
Capital expenditures	**(4,673,168)**	(35,909,432)	(5,871,044)
Proceeds from sale of oil and gas properties	**2,340,882**	18,000	184,638
Net cash used in investing activities	**(2,388,845)**	(36,069,944)	(5,847,900)
Cash flows from financing activities:			
Payments on revolving credit facility	**(5,500,000)**	(8,000,000)	(3,000,000)
Payment of revolving credit facility fees		(646,673)	
Borrowings under revolving credit facility		37,000,000	
Treasury stock purchase, 608,400 shares at cost		(1,463,142)	
Proceeds from stock option exercises	**30,575**	7,500	13,102
Net cash provided by (used in) financing activities	**(5,469,425)**	26,897,685	(2,986,898)
Net increase (decrease) in cash	**3,684,898**	387,054	(1,229,578)
Cash and cash equivalents at beginning of year	**1,348,024**	960,970	2,190,548
Cash and cash equivalents at end of year	**$ 5,032,922**	$ 1,348,024	$ 960,970

Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Income taxes	**$ 792,016**	$ 326,458	$ 2,656,395
Interest	**$ 1,096,609**	$ 1,176,375	$ 431,108
Supplemental disclosures of non-cash investing activities:			
Property and equipment additions included in accounts payable	**$**	$	$ 1,482,156

The accompanying notes are an integral part of the financial statements.

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EQUITY OIL COMPANY

NOTES TO FINANCIAL STATEMENTS

1. Significant Accounting Policies:

A. The Company:

Equity Oil Company (Equity or the Company) is a Colorado corporation engaged in oil and gas exploration, development and production in the United States and Canada.

B. Cash and Cash Equivalents:

The Company considers all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents.

C. Accounting for Oil and Gas Operations:

The Company reports using the successful efforts method of accounting for oil and gas operations. The use of this method results in capitalization of those costs identified with the acquisition, exploration and development of properties that produce revenue or, if in the development stage, are anticipated to produce future revenue. Costs of unsuccessful exploration efforts are expensed in the period in which it is determined that such costs are not recoverable through future revenues. Exploratory geological and geophysical costs are expensed as incurred. The costs of development wells are capitalized whether productive or nonproductive.

The Company annually assesses undeveloped oil and gas properties for impairment. Any impairment recorded represents management s estimate of the decline in realizable value experienced during the year. The unamortized costs of proved properties which management determines are not recoverable are written off in the period such determination is made. The net capitalized costs of proved oil and gas properties are measured for impairment based on a comparison of the expected undiscounted future net revenues from each field with the related net capitalized costs at the end of each period. When the net capitalized costs exceed the undiscounted future net revenues, the carrying value is written down to fair value, which is determined using discounted future net revenues from the field. Reserve categories used in the impairment analysis considered all categories of proven reserves and probable and possible reserves, which are risk-adjusted based on the Company s drilling plans and history of successfully developing those types of reserves.

The provision for depreciation, depletion and amortization (DD&A) of proved oil and gas properties is computed using the unit-of-production method, based on proved oil and gas reserves.

Revenues associated with oil and gas sales are recorded when the rights and responsibilities of ownership passes and are net of royalties.

D. Concentration of Credit Risk:

Substantially all of the Company s accounts receivable are within the oil and gas industry, primarily from purchasers of oil and gas (see Note 6). Although diversified within many companies, collectability is dependent upon the general economic conditions of the industry. The receivables are not collateralized and, to date, the Company has experienced minimal bad debts. The majority of the Company s cash and cash equivalents is held by one financial institution located in Salt Lake City, Utah, and by one financial institution in Calgary, Alberta.

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1. Significant Accounting Policies, Continued

E. Equipment:

The provision for depreciation of equipment (other than oil and gas equipment) is based on the straight-line method using asset lives as follows:

Office equipment	10 years
Automobiles	3 years

When equipment is retired or otherwise disposed of, the cost and accumulated depreciation are removed from the accounts and any resulting gain or loss is included in the statement of operations.

F. Asset Retirement Obligation

In August 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, Accounting for Asset Retirement Obligations. SFAS 143 was effective for the Company beginning January 1, 2003. The most significant impact of this standard on the Company was a change in the method of accruing for site restoration costs associated with its oil and gas properties. Under SFAS 143, the fair value of asset retirement obligations is recorded as a liability when incurred, which is typically at the time the assets are placed in service. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities are accreted for the change in their present value and the initial capitalized costs are depreciated over the useful lives of the related assets.

The Company used an expected cash flow approach to estimate its asset retirement obligations under SFAS 143. Upon adoption at January 1, 2003, the Company recorded a retirement obligation of $3,147,061, an increase in property and equipment cost of $1,997,619, an increase in accumulated depreciation, depletion and amortization of $535,255 and a cumulative effect of accounting change of $1,061,865, net of benefit from taxes of $622,832.

The following table summarizes the change in the Company s asset retirement obligation liability during 2003:

Balance, December 31, 2002	$
Liability recorded upon adoption of SFAS 143	3,147,061
Accretion expense	219,220
Additions to asset retirement obligations	51,856
Payments	(175,754)
Balance, December 31, 2003	$ 3,242,383

At December 31, 2003, there are no assets legally restricted for purposes of settling asset retirement obligations. There was no impact on the Company s cash flows as a result of adopting SFAS 143 since the cumulative effect of change in accounting method and the charges to expense for depreciation and accretion are non-cash transactions.

The Company s estimated asset retirement obligation liability at January 1, 2002 was approximately $2.9 million.

The SFAS 143 impact on net income for the period ended December 31, 2003 was additional expense of approximately $369,000, or $0.03 per common share.

G. Intangible Assets

SFAS No. 141, Business Combinations, and SFAS No. 142, Goodwill and Intangible Assets, were issued by the FASB in June 2001 and became effective for the Company on July 1, 2001 and

Continued

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1. Significant Accounting Policies, Continued

January 1, 2002, respectively. SFAS No. 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, SFAS No. 141 requires companies to disaggregate and report separately certain intangible assets from goodwill. SFAS No. 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS No. 142, goodwill and certain other intangible assets are not amortized but rather are reviewed annually for impairment. One interpretation being considered relative to these statements is that oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves from both undeveloped and developed leaseholds should be classified separately from oil and gas properties as intangible assets on the Company s balance sheets. In addition, the disclosures required by SFAS No. 141 and No. 142 relative to intangible assets would be included in the notes to financial statements. Historically, the Company has included these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves as part of oil and gas properties, even after SFAS No. 141 and No. 142 became effective.

This interpretation of SFAS No. 141 and No. 142 would only affect the Company s balance sheet classification of oil and gas leaseholds. The Company s results of operations and cash flows would not be affected, since these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves would continue to be amortized in accordance with accounting rules for oil and gas companies provided in SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies.

At December 31, 2003 and 2002 the Company had net undeveloped leaseholds of approximately $1,992,800 and $2,562,000, respectively, that would be classified on the Company s balance sheet as intangible undeveloped leaseholds and net developed leaseholds of approximately $21,300,700 and $24,552,000, respectively, that would be classified as intangible developed leaseholds if the Company applied the interpretation currently being discussed.

The Company will continue to classify its oil and gas mineral rights held under lease and other contractual rights representing the right to extract such reserves as tangible oil and gas properties until further guidance is provided.

H. Foreign Operations:

Operations and investments in Canada have been translated into U.S. dollar equivalents at the average rate of exchange in effect at the transaction date. Foreign currency translation gains or losses during 2003, 2002 and 2001 were not material.

I. Net Income Per Common Share:

Basic earnings per share is computed by dividing the net income by the weighted average number of common shares outstanding. Diluted earnings per share is computed by dividing the net income by the sum of the weighted average number of common shares and the effect of dilutive unexercised stock options. As a result of dilutive options, 389,241, 129,600 and 266,200 shares of common stock were included in the computation of diluted net income per share. Options to purchase 862,000, 1,695,200, and 1,391,600 shares of common stock at prices ranging from $2.50 to $5.125 per share were outstanding at December 31, 2003, 2002 and 2001, respectively, but were not included in the computation of diluted earnings per share because the effect would have been antidilutive.

J. Discontinued Operations

During February and March 2003, three packages of Canadian oil and gas properties were sold for approximately $2.4 million, resulting in a gain of approximately $1.2 million ($655,168 net of tax). In accordance with the provisions of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, the results of operations and gain on sale of these properties have

Continued

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1. Significant Accounting Policies, Continued

been reflected as discontinued operations. Revenue from these Canadian oil and gas properties was approximately $150,000, $969,000 and $1,216,000 for 2003, 2002 and 2001, respectively. After the sales, the Company s remaining Canadian asset is its 50% interest in the Cessford Field located in southern Alberta.

K. 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 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 the reporting period. Actual results could differ from those estimates.

Significant estimates with regard to these financial statements include the estimates of proved oil and gas reserve volumes used in determining DD&A and impairment provisions and future dismantling and abandonment costs.

L. Derivative Instruments and Hedging Activities

The Company periodically enters into oil and gas financial instruments as required by its bank credit facility and to manage its exposure to oil and gas price volatility. The instruments are usually placed with counterparties that the Company believes are minimal credit risks. It is the Company s policy to only enter into derivative contracts with investment grade rated counterparties deemed by management to be competent and competitive market makers. The oil and gas reference prices upon which the price hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company.

The financial instruments are accounted for in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities , which established new accounting and reporting requirements for derivative instruments and hedging activities effective January 1, 2001. The adoption of SFAS No. 133 had no financial statement impact at the date of adoption. SFAS No. 133, as amended, requires that all derivative instruments subject to the requirements of the statement be measured at fair value and recognized as assets or liabilities in the balance sheet. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation is established at the inception of a derivative. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of SFAS No. 133, changes in fair value, to the extent effective, are recognized in other comprehensive income (loss) until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value of a derivative resulting from ineffectiveness or an excluded component of the gain/loss is recognized immediately in revenue in the statement of operations.

The terms of the Company s current credit facility require that not later than thirty days subsequent to the date of the new facility (April 12, 2002), not less than 50% of the Company s projected monthly production be hedged at price levels and terms acceptable to the lender. As of December 31, 2003, the Company had commodity price hedges in place for 5,000 MMbtu of natural gas per day thru April 30, 2004 under a costless collar. The hedge has a floor of $3.00 per MMbtu and a ceiling of $4.43 per MMbtu. The settlement price of each of the contracts for months during the year resulted in cash payments of $2,765,247 from the Company to the counterparty. During 2002 payments of $305,425 were made to the hedge counterparty. No hedging transaction occurred in 2001.

The fair value of the hedges at December 31, 2003, as computed by the counterparty, was a liability of $969,025. This amount is shown on the balance sheet as fair value of financial instruments. The Company does not intend to terminate the current commodity hedges prior to their expiration date.

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1. Significant Accounting Policies, Continued

M. Stock Based Compensation Plans

At December 31, 2003, the Company had one stock-based compensation plan. (See note 5). The Company applies APB Opinion No. 25 and related interpretations in accounting for this plan. Accordingly, no compensation cost has been recognized for options granted to employees under its fixed stock option plan.

On December 31, 2002, the FASB issued SFAS No. 148, Accounting for Stock Based Compensation Transition and Disclosure, which amends SFAS No. 123. SFAS No. 148 requires more prominent and frequent disclosures about the effects of stock-based compensation, which the Company has adopted for the period ending December 31, 2002. The Company continues to account for its stock based compensation according to the provisions of APB Opinion No. 25.

Had compensation cost for the Company s stock options been recognized based upon the estimated fair value on the grant date under the fair value methodology prescribed by SFAS No. 123, as amended by SFAS No. 148, the Company s net earnings and earnings per share would have been as follows:

	2003	2002	2001
Net Income, as reported	$ 2,115,123	$ 1,001,007	$ 2,281,117
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects.	14,221	135,144	75,563
Less: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(163,510)	(167,228)	(230,736)
Pro forma net income	$ 1,965,834	$ 968,923	$ 2,125,944
Net Income per share			
Basic: As reported	$ .18	$ .08	$ .18
Pro forma	$ .16	$ .08	$ .17
Diluted: As reported	$ .17	$ .08	$ .18
Pro forma	$ .16	$ .08	$ .16

2. Impairment of Proved Oil and Gas Properties:

The Company recorded non-cash impairment charges related to oil and gas properties of $0, $53,990, and $404,395 for 2003, 2002 and 2001, respectively.

3. Yolo County California Asset Acquisition:

During the second quarter of 2002, the Company purchased interests in 27 producing and 16 non-producing gas wells and associated undeveloped leaseholds located in Yolo County, California. This Sacramento Basin acquisition was completed on April 12, 2002 with an effective date of January 1, 2002. The interests acquired are working interests and the Company assumed operations of the properties on May 1, 2002. The total consideration for the properties was $32.0 million. Net proceeds from the effective date to the date of closing were netted against the purchase price and thus approximately $30.0 million was paid at closing.

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3. Yolo County California Asset Acquisition, Continued

The following unaudited pro forma financial information for the years ended December 31, 2002 and 2001 assumes the Yolo County asset acquisition occurred as of the beginning of the respective years. The pro forma results for 2002 and 2001 combine the Company s historical results for the year ended December 31, 2002 and 2001 with the historical results of the acquired assets for the same periods, after giving effect to certain adjustments, including additional DD&A and interest expense associated with the acquired assets. The pro forma results have been prepared for illustrative purposes only. Such information does not purport to be indicative of the results of operations which actually would have resulted had the acquisition occurred on the dates indicated, nor is it indicative of the results that may be expected in any future periods.

	2002	2001
Revenues	$ 27,242,068	$ 58,685,409
Net Income	$ 5,065,891	$ 25,189,562
Basic net income per common share	$ 0.41	$ 1.99
Basic weighted average shares outstanding	12,300,094	12,680,068
Diluted net income per common share	$ 0.41	$ 1.95
Diluted weighted average shares outstanding	12,429,710	12,946,226

4. Income Taxes:

The Company accounts for income taxes in accordance with SFAS No. 109, Accounting for Income Taxes. Deferred income taxes are provided using enacted tax rates applied to the difference between the tax basis of an asset or liability and its reported amount in the financial statements that will result in taxable or deductible amounts in future years when the reported amount of the asset or liability is recovered or settled, respectively.

	2003	2002	2001
Income from continuing operations before Federal, State and non-U.S. income taxes consists of the following:			
United States	$ 3,607,902	$ 1,445,347	$ 2,692,789
Canada	929,755	(139,925)	257,353
Total	$ 4,537,657	$ 1,305,422	$ 2,950,142

The provision for income taxes from continuing operations consists of the following:

	2003	2002	2001
Currently payable:			
U.S. income taxes (including alternative minimum tax)	$	$	$ 97,096
State income taxes	77,533	2,408	2,500

Canadian income taxes	528,335	75,957	107,568
Deferred tax expense	1,500,010	579,881	990,379
	$ 2,105,878	$ 658,246	$ 1,197,543

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4. Income Taxes, Continued

The components of the net deferred tax liability as of December 31, 2003 and 2002 consist of the following:

	2003	2002
Deferred tax assets:		
AMT credit carryforward	$ 445,563	$ 445,563
State income taxes	28,834	924
Deferred compensation	30,466	27,535
Geological and geophysical costs	443,126	516,709
Asset retirement obligation	1,198,709	
Foreign tax credit carryforward		104,486
Fair value of financial instruments	358,249	709,080
Statutory depletion carryforward		428,780
Net operating loss carryforward	387,112	1,468,779
	2,892,059	3,701,856
Valuation allowance		(104,486)
Total deferred tax asset	2,892,059	3,597,370
Deferred tax liabilities:		
Property and equipment	8,456,591	7,909,584
Other assets	33,336	57,645
Total deferred tax liability	8,489,927	7,967,229
Net deferred tax liability	$ 5,597,868	$ 4,369,859

The net deferred tax liability as of December 31, 2003 and 2002 is reflected in the balance sheets as follows:

Current deferred tax asset	$ (59,300)	$ (28,460)
Long-term deferred tax liability	5,657,168	4,398,319
	$ 5,597,868	$ 4,369,859

The provision for income taxes from continuing operations differs from the amount that would be provided by applying the statutory U.S. Federal income tax rate to income before income taxes for the following reasons:

	2003	2002	2001

Federal statutory tax expense	$ 1,542,803	$ 443,843	$ 1,003,048
Increase (reduction) in taxes resulting from:			
State taxes (net of federal benefit)	131,026	44,558	88,927
Canadian taxes (net of foreign tax credits)	606,453	226,540	323,418
Excess allowable percentage depletion	(198,692)	(107,899)	(253,978)
Other	24,288	51,204	36,128
Provision for income taxes	$ 2,105,878	$ 658,246	$ 1,197,543

At December 31, 2003, the Company had approximately $446,000 of alternative minimum tax credit carryforwards which can be carried forward indefinitely, and a net operating loss carryforward of approximately $1,047,000 which will begin to expire in 2021.

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5. Stock-Based Compensation Plan:

Under the 2000 Equity Oil Company Incentive Stock Option Plan, the Company may grant options to its employees, directors and consultants to purchase up to 1.2 million shares of common stock. The Company also has unexercised options outstanding under previous stock option plans. The options may take the form of incentive stock options or nonstatutory stock options. The exercise price of each option equals the market price of the Company s stock on the date of grant, and an option s maximum term is 10 years. Options are granted from time to time at the discretion of the Board of Directors, and vest over periods of one to five years from the grant date.

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 used for grants in 2003, 2002 and 2001, respectively: expected volatility of 50, 55 and 57 percent, risk-free interest rates of 2.0, 4.1 and 4.8 percent; expected life of 5 to 7 years and dividend yield of zero for each year.

	2003		2002	2001
Stock Options	**Shares (000)**	**Weighted-Average Exercise Price**	**Shares (000)**	