PRIMA ENERGY CORP
Form 10-K
March 15, 2004

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

FORM 10-K

þ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2003.

o Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

Commission file number 0-9408

PRIMA ENERGY CORPORATION

(Exact name of Registrant as specified in its charter)

DELAWARE	**84-1097578**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1099 18th Street, Suite 400, Denver, Colorado 80202
(Address of principal executive offices) (Zip Code)

(303) 297-2100
(Registrant s telephone number, including area code)

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

Securities registered pursuant to Section 12(g) of the Act
Common Stock, $0.015 Par Value
(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 o

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

Indicate by checkmark whether the Registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes x No o

The aggregate market value of the 9,221,894 shares of voting stock held by non-affiliates of the Registrant, based upon the closing price of the common stock on June 30, 2003 of $20.82 per share as reported on the Nasdaq National Market, was $191,999,833. Shares of common stock held by each officer and director and by each person who owns 10% or more of the outstanding common stock have been excluded in that such persons may be deemed affiliates.

This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 27, 2004, Registrant had outstanding 12,964,142 shares of Common Stock, $0.015 Par Value, its only class of voting stock.

Document Incorporated by Reference

Parts of the following document are incorporated by reference to Items 10, 11, 12, 13 and 14 of Part III of the Form 10-K Report: Definitive Proxy Statement for the Registrant s 2004 Annual Meeting of Stockholders.

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Code of Ethics for Senior Financial Officers
Subsidiaries of the Registrant
Independent Auditors Consent
Independent Reservoir Engineers & Geologists
Certification of Chief Executive Officer
Certification of Chief Financial Officer
Certifications of CEO and CFO

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PART I

ITEMS 1 and 2. BUSINESS and PROPERTIES

References in this report to Prima, the Company, we, us or our are intended to refer to Prima Energy Corporatio its consolidated subsidiaries. This report contains numerous forward-looking statements that are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. These include, without limitation, statements relating to future drilling and completion of wells, well operations, production, prices, costs and expenses, cash flow, investments, utilization of oilfield service equipment, reserve estimates (including estimates for future net revenues associated with such reserves and the present value of such future net revenues), business strategies, and other plans and objectives of Prima management for future operations and activities and other such matters. The words, believes, plans, intends, estimates, projects, expects, anticipates, strategy, budgeted and simil identify forward-looking statements.

Prima does not undertake to update, revise or correct any of the forward-looking information. Readers are cautioned that such forward-looking statements should be read in conjunction with Prima s disclosures under the heading: Cautionary Statement for the Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995 beginning on page 21 of this report.

General The Company

Prima was incorporated in April 1980 to engage in crude oil and natural gas related exploration, acquisition, development, production, and related business activities. In October 1980, Prima became publicly owned with a $3.6 million common stock offering. Our subsequent activities have primarily been related to oil and gas production operations, but have also included oil and gas property management, oilfield services, and, at times, natural gas gathering, marketing and trading. The substantial majority of Prima s consolidated assets and revenues continue to be related to its oil and gas production operations.

Our principal activities are currently organized into two active operating segments. The larger of these consists of the acquisition, exploration, development and operation of oil and gas properties. The second segment is comprised of oilfield service operations conducted for unaffiliated third parties and for Prima. Though at times in the past we have also been involved in oil and gas marketing and trading, and in gas gathering and compression operations, these activities were not significant during the three years ended December 31, 2003. See Note 7 of Notes to Consolidated Financial Statements included as a part of Item 8 of this Report for financial information pertaining to these industry segments.

Our oil and gas exploration, development and production operations are generally conducted within Prima Oil & Gas Company, a wholly owned subsidiary. We conduct most other activities within wholly owned subsidiaries of Prima Oil & Gas Company, including Action Oil Field Services, Inc. and Action Energy Services for oilfield services.

We have conducted our activities principally in the Rocky Mountain region of the United States. At the end of 2003, Prima owned or controlled mineral leasehold interests in over 510,000 gross, or 390,000 net, acres, predominately in the Denver-Julesburg (D-J) Basin of Colorado, the Powder River, Wind River, Big Horn and Green River Basins of Wyoming, and within the Wasatch Plateau and Overthrust Belt in Utah.

Historically, we have grown our proven oil and gas reserves and production primarily through acquiring oil and gas leaseholds and drilling wells to exploit and develop tight sand and coalbed methane (CBM) properties. Generally, the probability that such properties have hydrocarbons in place is estimated to be relatively high and the viability of establishing proved reserves is largely dependent on several factors, including: the market price for oil and gas; the costs of development, production and marketing; and determination of the amount of recoverable reserves and the rate at which such reserves can be extracted. To a lesser extent, we have added proved reserves through exploration activities and acquisition of properties with proved developed reserves. At the end of 2003, over 90% of our proved oil and gas reserves and production were associated with tight sand properties in the D-J Basin in eastern Colorado and CBM properties in the Powder River Basin in eastern Wyoming. The balance of our proved reserves and production at the end of 2003 related to properties in the Wind River Basin in central Wyoming and non-CBM wells in the Powder River Basin.

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We have identified more than 2,800 potential exploitation and development opportunities on our D-J Basin and Powder River Basin CBM-prospective acreage, of which 485 were assigned proved oil and gas reserves at year-end 2003. Most of the identified non-proved opportunities represent potential CBM drilling locations in the Powder River Basin, with the remainder comprised primarily of recompletion and refracturing projects and other drilling locations in the D-J Basin. This set of identified opportunities includes only those projects that we believe have the potential to be economically viable using future oil and gas prices reflected in commodity futures markets at the end of 2003. We have also developed an inventory of exploratory prospects in other areas, including the Green River Basin in western Wyoming, the Overthrust Belt in northeast Utah and the Uintah Basin in eastern Utah which could, if successfully tested, establish new areas for future exploitation and development activities.

Our oilfield service operations are presently conducted in two areas where Prima has an established base of exploitation and production operations. These are the D-J Basin and the CBM play in the Powder River Basin. Action Oilfield Services, which operates in the D-J Basin, owns various well servicing equipment including eight workover rigs, a swab rig, tractor trailer rigs for water hauling, and oilfield rental equipment, such as pumps, tanks and blowout preventers. Action Energy Services, which operates in the Powder River Basin, owns nine CBM drilling and service rigs. Our service companies provide services to both Prima and other operators, and during 2003 operations provided to unrelated parties generated approximately 12% of Prima s total consolidated revenues. While these operations have typically generated positive earnings and cash flow, and have also enabled us to exert more control over costs and the quality of work performed for some of our well operations, they have not historically constituted a significant portion of Prima s assets or operations.

The following is a brief summary of selected key financial and operating data reported by Prima at December 31, 2003:

- $177,217,000 of assets.
- $56,148,000 of net working capital (with $57,192,000 of cash and marketable securities).
- No long-term debt.
- Estimated net proved reserves of 125,796,000 Mcf of natural gas equivalents (Mcfe), with a pre-tax net present value using a 10% discount factor (PV10) of $239,800,000, based on constant year-end average price realizations of $4.95 per Mcf of natural gas and $32.88 per barrel of oil. The related after-tax standardized measure of discounted future net cash flows was $158,979,000.
- Lease holdings of approximately 473,000 gross (360,000 net) undeveloped acres and 37,000 gross (30,000 net) developed acres.
- Operations of 708 productive wells (91% of the productive wells in which we own a working interest).

For the year ended December 31, 2003, we reported the following:

- Net income of $23,795,000.
- Net cash provided by operating activities of $46,149,000.
- Average daily net production of 35,658 Mcf of natural gas and 1,099 barrels of crude oil (42,252 Mcfe).
- Average price realizations of $3.53 per Mcf of natural gas and $31.71 per barrel of crude oil.

Strategy

Objectives. We seek to create shareholder value by identifying, evaluating and capturing opportunities related to the oil and gas industry. Most of our investment activities have been, and are projected to be, associated with our exploration and production operations, including the acquisition, exploration, development, and exploitation of properties, and production of oil and gas. We have also invested and conducted operations in oilfield services, gas gathering and processing, and in oil and gas marketing and trading, and we intend to continue seeking such opportunities in the future. One of Prima s goals is to be among the lowest-cost full-cycle producers of oil and gas, and to realize among the highest cash flow margins for reinvestment, in the industry. Through our related activities in other segments of the energy business, we seek to complement and reinforce the achievement of goals in our exploration and production operations, and to enhance total returns to shareholders.

Acreage. We seek to acquire oil and gas leaseholds in prospective areas at reasonable costs and with attractive terms. We can potentially benefit from the activities of other operators in these areas as well as from our own activities.

Operations. We generally prefer to operate oil and gas properties in which we own significant economic interests. As operator, we are in a better position to control the costs, timing, quality and safety of work performed, and other factors that can affect the profitability of a property. In some instances, however, we may prefer to retain non-operating interests in properties where another operator has achieved economies of scale or has other operating advantages.

Exploitation. We intend to continue property exploitation activities in our principal operating areas. In the D-J Basin, we plan to continue well refracturing, recompletions and development drilling, to the extent warranted by ongoing results and market conditions. We also plan to continue exploitation activities targeting CBM in the Powder River Basin and conventional reservoirs in the Wind River Basin, depending upon the merits of each activity and subject to regulatory considerations. We generally assess these activities as low-to-moderate risk endeavors that can be undertaken whenever market conditions are projected to be adequate for projects to meet our investment criteria, provided we are able to obtain necessary approvals from regulatory authorities.

Exploration. We generally seek to allocate 5% to 20% of our capital expenditures budget toward higher-risk exploration activities. These activities may include leasehold acquisitions, geologic and geophysical evaluation, and drilling test wells on prospects. Our exploratory prospects can be either internally generated or result from acquiring interests in other operators prospects. The objective of our exploration activities is to expose a portion of our capital to higher-risk projects that we believe have the potential to deliver high rates of return if successful. As compared to individual exploitation opportunities, a successful exploration project could have a more significant impact on Prima s value but the likelihood of success is considerably lower.

Gathering, Marketing and Trading. We elect to market our own natural gas and crude oil production whenever we believe that we can enhance our net price realizations by doing so. At times, Prima may also own assets downstream of the wellhead, including, but not limited to, gathering and compression facilities. We invest in such downstream assets where we believe opportunities exist to enhance Prima s overall project economics by capturing an additional portion of the value chain from the wellhead to the burner tip. We may also gather, compress and market third-party gas, if we expect that project rates of return will be attractive.

Oilfield Services. We believe that we can, at times, achieve better control of the timing, quality and cost of work performed on our wells by owning and operating well servicing equipment. We also intend for these activities to constitute a separate business segment and profit center through providing such services to other operators.

Mergers, Acquisitions and Divestitures. We regularly review merger, acquisition and divestiture opportunities related to the oil and gas industry that could complement or enhance Prima s existing businesses. We intend to pursue, and if possible consummate, such transactions when we believe that they would improve the risk-adjusted returns realized by Prima s shareholders over the long term.

Derivatives. We periodically use commodity futures contracts to mitigate the impact of the volatility of oil and gas prices on a portion of our production and gas marketing activities. Our use of such derivatives is also intended to improve our average oil and gas price realizations over time, to enhance profitability, though such outcome cannot be assured. We may also elect at times to enter into derivatives contracts for volumes that exceed our projected total production, or which increase, rather than decrease, our exposure to a decline in oil and gas prices or expansion of basis differentials. We would consider establishing such positions if our analyses lead us to believe that prices are likely to move in a manner that would generate gains from the positions. Derivative positions for volumes greater than our expected production, or which would increase our exposure to a decline in oil and gas prices or expansion of basis differentials, would be speculative and would be limited in size to an amount that, in management s judgment would not be material to our balance sheet taken as a whole, but they might have a significant positive or negative impact on reported net earnings.

Oil and Gas Properties and Operations

Major Properties

Denver-Julesburg Basin

This basin has been under extensive development since the 1970 s and has been substantially drilled. However, continued development has been supported by improvements in fracturing (or frac) technology to enhance oil and gas recoveries from tight sand reservoirs and by higher oil and gas prices. Because of the additional drilling and well stimulations encouraged by these factors, the D-J Basin continues to be under very active development and basin-wide production is near all-time peak levels.

Our activities in the D-J Basin have been conducted primarily in the Wattenberg Area, which encompasses more than 1,000 square miles, between 20 and 55 miles northeast of Denver, Colorado. We have conducted operations in the D-J basin for more than 20 years, and at the end of 2003 we owned working interests in 455 wells in the area, 436 of which we operated. Our drilling and production activities to date in the D-J Basin have been centered in a portion of the Wattenberg Field where the primary productive reservoirs are found in the Codell and Niobrara formations, which blanket large areas of the field at depths of approximately 7,000 to 7,300 feet. These formations have moderate porosity and low permeability, and require fracture stimulation to establish economic production. Recoverable reserves from any individual wellbore are largely dependent on reservoir quality, sand thickness, and fracture stimulation techniques.

Our D-J Basin wells produce both natural gas and crude oil. Prima s natural gas production in this area averages approximately 1,240 Btu per Mcf at the wellhead. Natural gas liquids (propane, butane, ethane, isobutane, and pentane) are extracted from the well stream and sold separately by third-party gatherer/purchasers but their value is reflected in our wellhead price for natural gas. Our average gas price realizations per Mcf in this area have ordinarily slightly exceeded Rocky Mountain spot prices due to the high Btu content of the gas, but this relationship varies with market conditions and is dependent, in part, on the price levels of natural gas liquids. In 2003, our gas price realizations for D-J Basin production averaged $4.13 per Mcf, compared to the Colorado Interstate Gas (CIG) index average of $4.04 per MMBtu. Our crude oil in this area is sweet and generally commands a price comparable to oil traded on the New York Mercantile Exchange (NYMEX).

Prima s leasehold position in the D-J Basin at the end of 2003 included 19,110 gross (16,570 net) developed acres, and an additional 12,000 gross (11,000 net) undeveloped acres. Our estimated proved reserves in the D-J Basin at that date were approximately 53,753,000 Mcf of natural gas and 4,892,000 barrels of oil, or 83,105,000 Mcfe, representing 66% of our total estimated proved reserve quantities. During 2003, Prima s net production from D-J Basin properties averaged approximately 14,700 Mcf of gas and 1,065 barrels of oil, or 21,100 Mcfe, per day, accounting for 50% of our total oil and gas production and 59% of our oil and gas sales revenues (excluding hedging effects). Our net production from D-J Basin wells was less than 1% lower in 2003 than in 2002, reflecting roughly offsetting effects of natural depletion and new activities.

Codell/Niobrara wells that we recently drilled and completed in this area have generally cost approximately $285,000 and targeted approximately 200,000 to 250,000 Mcfe of gross recoverable reserves per well (excluding refracs, discussed below). At year-end 2003, we controlled approximately 200 potential drill sites in the D-J Basin, with 90 of these attributed proved undeveloped reserves. These proved locations have projected rates of return above 35% using futures prices reflected on forward markets on December 31, 2003. During 2003, we drilled 28 gross (27.0 net) wells in the D-J Basin, all of which were successfully completed and placed on production.

Advancements in refracturing (refrac) stimulation technology have enabled us to add deliverability and reserves from the Codell and Niobrara formations. A refrac is a procedure in which a formation in an older well that has been previously fractured at least once is stimulated by another fracture treatment. We generally target older wells with declining deliverability for restimulation. Prima performed 38 refracs in Wattenberg during 2003, with such activities primarily focused on the Codell formation. These had an average cost of approximately $120,000 and are projected to deliver rates of return in excess of 100% based on actual cash flows through year-end, projected incremental production and futures prices reflected on forward markets on December 31, 2003. At the end of 2003, we had 136 proven D-J Basin refrac projects reflected in our reserve report. During the fourth quarter of 2003, we conducted two well operations to fracture-stimulate the Codell formation for a third time, referred to as a tri-frac. Based on encouraging short-term performance results, we believe that tri-frac operations may provide future opportunities to add reserves and production on many of our existing D-J Basin wells, but none of these are included in estimated proved reserves at the end of 2003.

We plan to continue our development and exploitation activities in the D-J Basin, and are currently budgeting for capital investments in the area aggregating approximately $14 million in 2004. Planned activities include drilling approximately 35 new Codell/Niobrara wells and refracing, tri-fracing or recompleting approximately 50 wells in the Codell and/or the Niobrara formation. Our plans are subject to revision, however, based on economic conditions, performance results, activities conducted in other areas, and other factors. New wells, refracs and recompletion operations in the D-J Basin are characterized by flush production at relatively high rates for a few months, after which relatively shallow decline rates are established at lower production levels. Therefore, we may accelerate these operations when oil and gas prices are high or defer them when prices are low, to enhance the impact on investment returns from the flush production.

Powder River Basin Coalbed Methane

At December 31, 2003, we controlled leaseholds covering approximately 110,000 gross (97,000 net) acres in the Powder River Basin CBM play and had established proved gas reserves totaling approximately 34,965,000 Mcf on a small portion of this acreage. These CBM reserves represented 28% of Prima s total estimated proved oil and gas reserve quantities at the end of 2003. Our net gas production from this area increased from an average of approximately 4,300 Mcf per day in 2002 to 17,700 Mcf per day in 2003, due to performance of our Porcupine-Tuit property where wells placed on-line in 2002 produced for a full year and additional wells were drilled and brought on-line. In 2003, the Powder River Basin CBM area accounted for 42% of our total oil and gas production and 32% of our oil and gas sales revenues (excluding hedging effects). Based on current market conditions and excluding the potential impact of exploratory discoveries or proved property acquisitions, we expect that our future activities in the Powder River Basin CBM area will account for significant portions of our capital expenditures, proved reserve additions and new sources of production during the next several years. There is no certainty, however, that future activities will generate the results that we currently project.

As of December 31, 2003, we had drilled 418 wells and acquired five wells in the Powder River Basin CBM play. At that date, 105 of these were connected to sales lines (including 99 that were producing gas), 153 were waiting on connection to gathering systems (of which 16 were already on pump, in the process of being de-watered), and the remaining wells were sold (most in 2002). We anticipate that approximately 130 of the 153 wells awaiting connection to gathering systems will be connected during the second half of 2004 and will begin gas production after sufficient de-watering has occurred. The remaining wells awaiting hook-up will be connected to a gathering system once wider-scale development occurs in the areas where these wells are located. Based on engineering estimates prepared as of the end of 2003, our reserve report for this CBM area included 254 proved undeveloped locations and identified over 2,350 additional non-proved prospective drill sites on our leaseholds, subject to economic viability that will be dependent upon projected regional gas prices, estimated development and operating costs, future drilling results from activities by Prima and other operators, and other factors. Prima is majority (often 100%) owner and operator of all of the Powder River Basin CBM properties where it owns a working interest.

The CBM play in the Powder River Basin is prospective over a vast geographic area encompassing approximately three million acres in northeastern Wyoming and southeastern Montana. Industry drilling activity to date has primarily been focused in Wyoming, where most of the acreage and thicker coal seams lie. According to the Wyoming Oil & Gas Commission, over 16,000 Powder River Basin CBM wells have been drilled in the state through the end of 2003 and

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approximately 12,000 of these wells were producing an aggregate of approximately 950 MMcf of natural gas per day during December 2003. At times during the past five years, this has been the most active drilling play in the United States. Although activity levels moderated in 2002 and 2003, due to unsettled federal land use issues (discussed below), depressed regional gas prices in 2002, and other factors, significant estimated potential gas reserves remain unexploited in the area.

The primary target coals are found in the Fort Union formation at depths ranging from 600 feet to 2,200 feet. It is common to encounter multiple coal zones varying in thickness from a few feet to over 150 feet between these depths. The methane in coal beds is adsorbed, or attached, within the coal layers and is held in place by water within the coals. When water is produced from the coal seam, the pressure is reduced, allowing the gas to desorb from the coal. Operators in the area have experienced de-watering times ranging from a few days to over one year, with the de-watering time influenced by well density, coal depth, permeability, gas content, structure and other factors. Gas production rates from individual wells in the play have ranged from a few Mcf per day to over 1,000 Mcf per day after sufficient de-watering.

Significant industry CBM drilling activities in this area began in 1994 and have primarily been focused on developing reserves in the Wyodak coal, on the east side of the basin. Typically, costs for these wells (including allocable costs for related surface equipment and infrastructure) averaged $70,000 to $90,000 per well, and yielded gross gas reserves averaging 250,000 to 300,000 Mcf per well. Future drilling operations are expected to be focused on development of the Big George, Wall and other coal seams that are generally deeper and often thicker than the Wyodak coal. We expect that as these deeper, thicker coals are developed, the gas reserves and production per well and the average drilling, completion and operating costs per well will be greater than experienced so far to develop the Wyodak coal seam.

To produce gas in this CBM play, wells generally must be hooked-up to a low-pressure gathering system and compression, commonly referred to as screw compression, which typically holds wellhead pressure to less than 10 pounds per square inch gauged (psig). The gas must then move through a gathering system where, at its terminus, gas needs to be further boosted to about 1,400 psig to enter a high-pressure header-system line. This high-pressure boost is commonly referred to as reciprocating (or recip) compression. CBM gas from this area is generally somewhat less than 1,000 Btu per Mcf and may require carbon dioxide extraction to meet interstate pipeline gas quality specifications. Due to relatively high compression and transportation costs, net price realizations for this gas are below Rocky Mountain indices. The amount of the discount varies with the nominal level of the indices, Btu content of the gas, location of the property, fuel use and other factors, but in 2003 Prima s realized price on production from CBM wells averaged $2.87 per Mcf, compared to the CIG index average of $4.04, for a difference of $1.17 per Mcf.

Our CBM-prospective net acreage holdings in the Powder River Basin at the end of 2003 were comprised of approximately 83% federal, 7% state, and 10% fee (private) leases. Generally, the federal leases have an initial ten-year term, state leases have a five-year term, and the terms of fee leases vary from a few months to several years. The primary lease terms of federal acreage have generally been extended for the period that access to the lands has been restricted while an Environmental Impact Statement (EIS) was pending or subject to legal challenge after its completion.

On April 30, 2003, the BLM issued the final Record of Decision (ROD) in relation to its EIS regarding future CBM drilling in the Powder River Basin. Among other conditions for future operations, this ROD requires additional surveys for plant and animal species and cultural artifacts, and noxious weed mitigation. We have filed permit applications for approval by the BLM under the terms of the new EIS, but cannot predict whether or when such permits will be granted. Since the issuance of the final ROD, the BLM has been reviewing their permitting processes in an effort to eventually facilitate issuance to industry of approximately 3,000 drilling permits per year for this area, but actual issuances of permits have so far continued to be made at a fraction of that pace. BLM permit issuances may also be affected for some period by several pending lawsuits that were filed shortly after the ROD was issued, challenging portions of the BLM s decision. At this time, we are unable to predict the outcome of this matter or its impact on our planned operations in the Powder River Basin. A significant portion of the wells we plan to drill in 2004 would require federal permits to be issued by the BLM. However, we do not expect that any limitations on our ability to drill during 2004 will affect the rate of our production until late in the year.

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The Wyoming Department of Environmental Quality (DEQ) is responsible for considering applications for water discharge permits and air discharge permits, which are required to operate natural gas fired compressors. Water produced from CBM wells is generally potable (drinking water quality) and permits to discharge water on the surface had generally been attainable early in development of the eastern side of the basin. However, issuance of permits to surface discharge water was significantly slowed during the past two years in order to allow further study of the potential impacts of the mineral content of the water on agriculture and wildlife. It is expected that, in the future, the Wyoming DEQ will generally require water management techniques other than surface discharge, such as collection in containment reservoirs or treating, in accordance with conditions also outlined in the BLM s EIS. These additional requirements will add to the costs of CBM development and production, but we do not believe that they will materially impact the economic viability of the play. We have not encountered, nor do we expect to encounter, significant difficulties in obtaining air permits for our CBM operations from the DEQ.

The transportation infrastructure in this basin is currently capable of moving approximately 1,500,000 Mcf per day of natural gas, compared to the estimated 950,000 Mcf per day produced in December 2003. Downstream of these header systems serving the Powder River Basin, the pipeline grid has been significantly enhanced over the past year by several interstate pipeline expansions, creating adequate capacity at present to transport gas from the Rocky Mountain region to other markets. We do not currently own firm transportation for our own account, and so are relying on availability of capacity on pipelines in order to market our gas.

We established our first significant Powder River Basin CBM production in 2001 from the Stones Throw property (in the northern part of the play), where gross production rates increased over several months to a level in excess of 8,000 Mcf per day (approximately 6,800 Mcf net) shortly before the time the property was sold in March 2002. In July 2002, we initiated production from 27 wells at our Porcupine-Tuit CBM property (in the southern part of the play). Production from this property increased over the balance of the year and in 2003, as wells de-watered, more wells were drilled and hooked up, and additional third-party-owned compression capacity was installed. At the end of 2003, 85 wells had been drilled and hooked up at Porcupine-Tuit and were producing at a combined gross rate of approximately 25,000 Mcf per day (approximately 19,500 Mcf net). Overall, predominantly reflecting contributions these two properties, Prima s Powder River Basin CBM properties accounted for net production averaging approximately 4,000 Mcf per day, 4,300 Mcf per day, and 17,700 Mcf per day, respectively, in 2001, 2002, and 2003. These early-stage developments primarily targeted relatively shallow Wyodak coals.

During 2003, Prima drilled 76 gross (57.7 net) Powder River Basin CBM wells and our direct capital expenditures on the Powder River Basin CBM play, including surface equipment and related infrastructure, totaled approximately $8.5 million. Activities during the year were focused on Porcupine-Tuit, where we drilled 24 wells, and on project areas in the central part of the basin where most of our core undeveloped land holdings in the play are concentrated. These include our Kingsbury, Cedar Draw and North Shell Draw project areas, located approximately 15 to 25 miles west and northwest of Gillette, Wyoming, where 2003 drilling activities were conducted to continue evaluation and development of four main identified coal seams, from the shallower Lower Anderson coal to the deeper Wall coal, found at depths ranging from 700 feet to 2,000 feet. These areas account for most of the previously-drilled wells that we intend to tie in to a gathering system in 2004. Further west lie additional key project areas where we control significant acreage, including Wild Turkey, where the Big George coal is found at approximately 1,300 feet, and Fortification Creek, which also has multiple developable coal seams at depths ranging from 700 feet to 1,600 feet. We anticipate that it will take some time to establish significant proved CBM reserves and production from these areas, particularly from the deeper coals, as they are untested in much of the basin and extensive de-watering will likely need to occur before commercial quantities of gas production can be realized. Furthermore, it is not assured that these projects will ultimately be successful and that they will yield significant reserves and production.

We are currently budgeting for capital investments in the Powder River Basin CBM play during 2004 of approximately $24 million for drilling costs, production equipment, and related infrastructure costs. Planned activities are focused primarily in the Kingsbury, Cedar Draw, North Shell Draw and Wild Turkey project areas. Our preliminary plans call for drilling an estimated 150 wells and hooking up most of these and 130 previously-drilled wells into gathering systems, as well as investing in infrastructure such as power connections and water management facilities. Due to uncertainties regarding regulatory approvals needed to conduct these activities, we can make no assurance that we will be able to conduct the operations that we have planned or that we will reach the targeted level of capital investments.

Other

Powder River Basin, Conventional. At the end of 2003, Prima owned working interests in 17 gross (12.8 net) conventional wells in the Powder River Basin, and deep-rights (below the coals) under 2,000 gross (1,400 net) developed acres and 160,000 gross (146,500 net) undeveloped acres in the area. Our estimated proved reserves at the end of 2003 from conventional sands in the Powder River Basin totaled 2,602,000 Mcf of natural gas and 60,000 barrels of oil, or 2,964,000 Mcfe, representing 2.4% of our total estimated proved reserve quantities. During 2003, Prima s net production from these properties averaged approximately 1,400 Mcfe per day, accounting for 3.3% of our total oil and gas production and 3.4% of our oil and gas sales revenues (excluding hedging effects). Our net production from Powder River Basin conventional wells was 24% lower in 2003 than in 2002, reflecting natural depletion, as no new wells were drilled. No significant activity is currently planned for 2004.

Cave Gulch (Wind River Basin). At the end of 2003, Prima owned primarily non-operated working interests in 50 gross (3.8 net) wells in the Cave Gulch Field in the Wind River Basin. Our Wind River Basin acreage position is comprised of 1,240 gross (170 net) developed acres and 37,000 gross (23,000 net) undeveloped acres. Prima s estimated proved reserves at the end of 2003 attributable to this area totaled 4,644,000 Mcf of natural gas and 14,000 barrels of oil, or 4,727,000 Mcfe, representing 3.8% of our total estimated proved reserve quantities. During 2003, Prima s net production from the Cave Gulch Field averaged approximately 2,000 Mcfe per day, accounting for 4.7% of our total oil and gas production and 5.3% of our oil and gas sales revenues (excluding hedging effects). Our net production from Cave Gulch wells was 20% higher in 2003 than in 2002, as new wells and recompletions offset natural depletion. Prima s capital investments at Cave Gulch in 2003 aggregated approximately $2.3 million, including costs of participating in drilling 17 gross (1.3 net) wells. The operator has indicated that up to six gross (0.5 net) additional wells are preliminarily planned for 2004, for a projected net Prima investment of approximately $1 million.

Coyote Flats Prospect. Prima s Coyote Flats Prospect is located 15 to 25 miles northwest of Price, Utah, and is approximately 15 miles northwest of the Drunkard s Wash Field, which is expected to ultimately produce in excess of 1.2 Tcf of natural gas from the Cretaceous Ferron coals and sandstones. We control approximately 75,000 gross (73,000 net) undeveloped acres within the prospect area. Data from drilling operations conducted on the Coyote Flats acreage during the 1950 s indicated gas shows from the Emery coal seam interval, the Ferron sand and the Dakota sand. Our primary exploratory objectives at Coyote Flats are coal beds in the Emery member of the Mancos shale and the Ferron sandstone interval. Emery coals are found across the majority of the lease position at depths below 3,000 feet, while the Ferron sandstone is found on the acreage at depths ranging from 5,000 to 8,500 feet.

During the fourth quarter of 2002, we drilled a 100%-owned exploratory well on the Coyote Flats Prospect, to begin to evaluate the Emery coals and the Ferron sandstone. The Scofield-Thorpe #22-41 well was drilled and cased to a total depth of 6,247 feet, before operations were suspended for the winter. The well encountered an aggregate 122 feet of Emery coal, from numerous coal beds, including eight with a thickness exceeding five feet, and the Ferron sandstone section was drilled between 5,991 and 6,247 feet. Encouraging gas shows were encountered while drilling from several of the Emery coal beds and from fractured shales and sandstones in the Ferron section.

In the second half of 2003, Prima initiated completion and testing of the Ferron sandstone reservoirs in the Scofield-Thorpe #22-41 well. We completed a 30-day production test on the well followed by a 7-day pressure build-up test. The test results were encouraging, as gas rates of 1,100 Mcf per day and water rates of 150 bpd were measured, with gradually increasing gas rates and decreasing water rates. During 2004, we plan to conduct follow-up drilling on the Coyote Flats Prospect to further evaluate the Ferron sandstone reservoirs, and we also expect to initiate a multi-well pilot program to test the Emery CBM potential. We may seek a partner to participate in these operations.

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East Clear Creek Prospect. We control approximately 9,000 gross and net acres in our East Clear Creek Prospect, located approximately 15 miles west of Price, Utah. This prospect is one mile east of Clear Creek Field, and two miles west of the Gordon Creek Field, both of which have produced from the Cretaceous Ferron sandstone. The Clear Creek Field produced in excess of 135 Bcf from 16 wells and the Gordon Creek Field was recently producing at a gross rate of approximately 2,700 Mcf per day from five wells placed on line over the past year. Prima has been working with the U.S. Forest Service and the Bureau of Land Management on an EIS that must be completed before drilling permits will be issued on this prospect. We expect to receive a permit to drill a test well on this prospect later this year and plan to drill a well as soon as practicable thereafter that will target the Ferron and Dakota sandstones at a depth of approximately 7,000 feet on a seismically-defined structure.

Flat Canyon Prospect. Prima owns approximately 6,600 gross and net acres under its Flat Canyon Prospect, located in Emery County, Utah. Our acreage immediately offsets the Flat Canyon Field, which was discovered in 1952. The Flat Canyon Field has produced 9.6 Bcf of natural gas and 14,000 barrels of oil from six wells completed in the Cretaceous Ferron sandstones. We plan to test the Cretaceous Ferron and Dakota formations on the prospect at depths between 6,500 and 7,500 feet. Prima is currently working with the U.S. Forest Service and the Bureau of Land Management to permit a well on this prospect.

Christmas Meadows Prospect. Prima currently holds leases or farmout rights representing approximately a 47% working interest in the Table Top Federal Unit, which is comprised of approximately 24,000 gross acres in Summit County, Utah, roughly 30 miles south of Evanston, Wyoming. The Christmas Meadows prospect, within the Unit, is a large seismically-defined anticlinal closure along the Uinta Mountain front, within the Rocky Mountain Overthrust Belt. Several potential pay sands have been identified down to an estimated depth of approximately 18,000 feet. This project has been delayed for several years and the federal leases have been temporarily suspended while the U.S. Forest Service was preparing an EIS and considering a revision of the forest plan for the area. It currently appears that these issues may be near resolution, enabling a test well to be spudded in the second half of 2004 or in 2005. The initial test well is expected to be drilled to a depth of approximately 15,000 feet to test the Frontier and Dakota sandstones. Once operations in the unit are commenced, Prima and its partners will have approximately six months to establish capability of commercial production, otherwise certain leases will expire. We anticipate participating in the test well for all or a portion of our current working interest.

Merna Prospect. Prima owns an average 35% working interest in 74,000 gross acres in the greater Merna area, located in the northern Green River Basin, in Sublette County, Wyoming. The Merna anticlinal structure is 20 miles northwest of the prolific Pinedale Anticline, where the over-pressured Cretaceous Lance and Mesaverde formations are under extensive development. The same objectives are targeted on the Merna Prospect. In late 2002, the Miller Federal #7-4 well was drilled by another operator along the Merna anticline on lands in which Prima had farmed out its 50% working interest. An affiliate of this operator installed a 36-mile natural gas pipeline to facilitate extended production testing and market sales for this well and future wells that might be drilled in the Merna area. The Miller Federal #7-4 well exhibited strong gas shows at high pressure while drilling but subsequent completion of the well in 2003 resulted in only modest production rates. This well and previous drilling in the area have established the presence of a thick Lance sand interval with gas in place, but project success will likely depend on encountering naturally-fractured reservoirs or successful application of fracture stimulation, due to relatively low porosity and permeability. In 2002, a large regional 3-D seismic survey that encompassed a large portion of the Merna Prospect acreage was completed. In late 2003, another operator initiated a test well on Merna acreage in which Prima held an interest. Prima is participating in the Sage Flat Federal #17-20 well, with a 6.3% working interest before payout and a 10.9% working interest after payout. The Sage Flat Federal #17-20 well is located three miles north of the Miller Federal #7-4 well.

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Proved Reserves

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Net proved reserves as of December 31, 2003, 2002 and 2001 were estimated by Prima s engineers and audited by Netherland, Sewell and Associates, Inc., independent petroleum engineers.

The table below sets forth the estimated quantities of net proved reserves attributed to our property interests at the end of each of the last three years, and the present value of estimated future net cash flows attributed to such reserves using prices in effect as of the respective year-end dates, held constant. The average net realizable prices used to estimate proved reserve quantities at the end of 2003, 2002, and 2001, respectively, were as follows: $4.95, $2.64, and $1.94 per Mcf for natural gas; and $32.88, $31.30, and $19.71 per barrel of oil. In accordance with Securities and Exchange Commission guidelines, projected future net cash flows from production of proved reserves were discounted by ten percent per annum to derive present values and the Standardized Measure of discounted future net cash flows after income taxes. The 10% discount factor is not necessarily a market rate, and present value, no matter what discount factor used, is materially affected by assumptions as to future prices and costs and timing of future production, which may prove to be inaccurate. For further information concerning estimated proved reserves and the discounted future net cash flows related to these reserves, see unaudited Supplementary Oil and Gas Information in Note 12 within the Notes to Consolidated Financial Statements.

	2003	2002	2001
Estimated proved natural gas reserves (Mcf)	96,000,000	87,440,000	115,222,000
Estimated proved oil reserves (barrels)	4,966,000	3,944,000	3,394,000
Present value of estimated future net cash flows, before future income tax expense	$239,800,000	$128,843,000	$ 91,905,000
Standardized measure of discounted future net cash flows	$158,979,000	$ 91,279,000	$ 66,801,000

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing and amounts of development expenditures. Oil and gas reserve engineering should be recognized as a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate is a function of the quality of available engineering and geological data and interpretation, and judgment. Results of drilling, testing and production after estimates are prepared may justify revisions. Accordingly, reserve estimates are often materially different from the quantities of oil and natural gas that are ultimately produced. We are not currently aware of any developments subsequent to December 31, 2003 that we believe would warrant a significant upward or downward revision to our estimated proved reserves as of that date. Oil and natural gas prices have historically been volatile and are expected to continue to be so in the future. Changes in product prices affect the economic limits and, therefore, recoverable reserve quantities of oil and gas wells, as well as the present value of estimated future net cash flows and the standardized measure of discounted future net cash flows.

Since January 1, 2003, we have filed Department of Energy Form EIA-23, Annual Survey of Oil and Gas Reserves, as required of operators of domestic oil and gas properties. There are differences between the reserves as reported on Form EIA-23 and reserves as reported herein. Form EIA-23 requires that operators report on total proved developed reserves for operated wells only and that the reserves be reported on a gross operated basis rather than on a net interest basis.

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Production

The following table summarizes information with respect to our producing oil and gas properties for each of the periods shown.

	2003	2002	2001
Quantities sold:			
Natural gas (Mcf)	13,015,000	8,343,000	9,277,000
Oil (barrels)	401,000	373,000	431,000
Total natural gas equivalents (Mcfe)(1)	15,421,000	10,580,000	11,863,000
Average sales price (including hedging effects):			
Natural gas (per Mcf)	$ 3.53	$ 1.97	$ 3.60
Oil (per barrel)	$ 31.71	$ 25.14	$ 25.88
Total natural gas equivalents (per Mcfe)(1)	$ 3.80	$ 2.44	$ 3.76
Average production costs, including production taxes, per Mcfe (1)	$ 0.61	$ 0.49	$ 0.56

(1) Oil production has been converted to a common unit of production (Mcfe of natural gas) on the basis of relative energy content (one barrel of oil to six Mcf of natural gas).

Productive Wells

The following table summarizes our total gross and net productive wells as of December 31, 2003.

	Productive Wells			
	Oil		Gas	
	Gross (1)	Net (2)	Gross (1)(3)	Net (2)(3)
Operated:				
Colorado	21	20.0	415	383.6
Wyoming			272	232.5
Non-operated:				
Colorado			19	8.1
Utah			1	0.4
Wyoming			53	4.7
Total (4)	21	20.0	760	629.3

Additionally, we own royalty interests in 148 gross wells that are not included in the above table.

(1) A gross well is a well in which a working interest is held. The number of gross wells is the total number of wells in which a working interest is owned.

(2) A net well is deemed to exist when the sum of fractional ownership interests in gross wells equals one. The number of net wells is the sum of the fractional working interests owned in gross wells expressed as whole numbers and fractions thereof.

(3) Includes 153 gross (124.1 net) CBM wells in Wyoming that were awaiting hook-up at year-end.

(4) Wells are classified as oil wells or gas wells according to predominate production stream. Multiple completions (28 wells) are counted as one well.

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Developed and Undeveloped Acreage

At December 31, 2003, our oil and gas lease holdings were as follows:

	Developed Acreage (1)		Undeveloped Acreage (2)	
Location	**Gross (3)**	**Net (4)**	**Gross (3)**	**Net (4)**
Denver-Julesburg Basin	19,110	16,570	12,000	11,000
Green River Basin	320	40	86,000	36,000
Powder River Basin	14,870	12,900	177,000	158,000
Uinta Basin	160	160	105,000	102,000
Wind River Basin	1,240	170	37,000	23,000
Other basins	1,500	60	56,000	30,000
Total	37,200	29,900	473,000	360,000

(1) Developed acres are acres spaced or assigned to productive wells.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

(3) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. We have generally been able to obtain extensions of the primary terms of our federal leases for the period that we have been unable to obtain drilling permits due to a pending EIS or related legal challenges. The following table sets forth the expiration periods of the gross and net acres subject to leases summarized in the table of undeveloped acreage, unless such leases are currently held by production from a portion of the lease that has been developed.

	Acres Expiring	
Twelve Months Ending:	**Gross**	**Net**
December 31, 2004	51,000	25,000

December 31, 2005	82,000	56,000
December 31, 2006	34,000	34,000
December 31, 2007	25,000	22,000
December 31, 2008	80,000	73,000
December 31, 2009 and later	126,000	117,000
	398,000	327,000

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Drilling Activities

Certain information with regard to our drilling activities for the years ended December 31, 2003, 2002 and 2001 is set forth below:

	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	67	51.1	55	50.1	123	121.3
Dry						
	67	51.1	55	50.1	123	121.3
Exploratory:						
Productive	52	34.7	18	11.0	14	14.0
Dry					2	0.3
	52	34.7	18	11.0	16	14.3
Total:						
Productive	119	85.8	73	61.1	137	135.3
Dry					2	0.3
	119	85.8	73	61.1	139	135.6

Present Activities

Year-to-date through February 27, 2004, we had drilled nine gross and net wells in the D-J Basin. Six of these wells were producing at that date, one was waiting on tie-in to a sales line and two were waiting on completion. We also restimulated (refraced or tri-fraced) 14 gross (12.8 net) wells in the D-J Basin, all of which have been restored to production. During this same period, we drilled five gross and net wells in the Powder River Basin CBM play and participated in drilling two non-operated (0.1 net) wells in the Cave Gulch area, all of which were waiting on completion as of February 27, 2004.

Natural Gas and Oil Marketing, Trading and Price Risk Management

Prima s marketing and trading activities may include marketing our own production, marketing the production of other owners in wells that we operate, and the purchase and resale of third-party owned production. This oil and gas production is principally sold to end users, marketers, refiners and other purchasers having access to pipeline facilities or the ability to truck oil to local refineries. The marketing of oil and gas can be affected by a number of factors that are beyond our control and which cannot be accurately predicted. At times, we use financial instruments to hedge the price of a portion of our production or production of others that we have committed to purchase for resale.

In 2003, revenues from the sale of Prima s natural gas production, including related hedging effects, totaled $45,911,000, representing 78% of our and gas sales and 65% of our consolidated total revenues. Revenues from the sale of Prima s crude oil in 2003, including hedging effects, totaled $12,711,000, representing 22% of our oil and gas sales and 18% of our consolidated total revenues.

Natural Gas

The terms and conditions of our natural gas sales contracts vary as to price, quantity, term and other conditions, but in general follow 30-day index or day-to-day spot market prices. We occasionally sell gas at a fixed price for periods greater than 30 days as an effective price hedge, but had no such fixed-price sales arrangements in effect at year-end 2003. We currently have two significant purchasers for our natural gas, Duke Energy Field Services, LLC (Duke) and Western Gas Resources, Inc (Western). Neither of these companies is affiliated with Prima and, while loss of either as a purchaser or customer might have a material adverse effect on our business, we believe that we could arrange to sell our gas to alternate customers on reasonably comparable terms.

Natural gas produced in the D-J Basin is high in heating content and must be processed to extract natural gas liquids. Duke purchases most of our D-J Basin gas at the wellhead, under contracts that provide for Prima to receive fixed percentages of the proceeds generated by Duke s sale of residue gas and natural gas liquids after the gas is processed at Duke s plants. Net sales to Duke in 2003 accounted for approximately $19,193,000, or 27% of our total consolidated revenues.

Western purchases much of our gas production in the Powder River Basin, including CBM gas from wells in the Porcupine-Tuit area. This CBM gas, which accounted for over 95% of our sales to Western in 2003, is sold at the inlet to Western s compression facilities at prices based on the monthly CIG index less certain costs for compression and transportation. Net sales to Western in 2003 accounted for approximately $19,062,000, or 27%, of our total consolidated revenues.

Our current gas gathering and marketing agreements generally arrange to get our gas from the wellhead into high-pressure header systems or interstate pipelines. We have not, however, contracted for downstream transportation on a firm basis. As such, we have no liability to pay reservation (demand) charges for header or pipeline capacity, but we also have no assurance that our gas will flow every day and we are at risk that regional imbalances between gas supply and pipeline capacity will unfavorably impact the gas prices that we realize for our production. No significant curtailments of gas production occurred during the three-year period ended December 31, 2003, but limited pipeline capacity did create conditions during several months, particularly between mid-2002 and mid-2003, in which the netback price that we received for our natural gas was significantly below prices being paid for gas elsewhere in the country. Due to expansions of pipeline capacity during 2003, we do not expect such conditions to recur in the near-term.

At times, we have also engaged in purchasing and re-selling third-party gas within our areas of operations. These arrangements typically provide for the purchase of natural gas at a known price or index, with a corresponding sale at a net margin. However, from time to time we may have open purchase or sale commitments without corresponding re-sale contracts, which could result in losses. Prima s Chief Executive Officer reviews such opportunities before commitments are made and we closely monitor the mark-to-market gains or losses of such positions. We had no purchase-for-resale trading obligations outstanding at the end of 2003 and had entered into no commitments after year-end 2003 through February 27, 2004.

Oil

Our oil production is typically sold to refiners, marketers and other purchasers that truck it to local refineries or pipelines. The price is generally based on a prevailing spot market index, such as NYMEX, with adjustments for quality and location. We currently have one significant purchaser of crude oil, Valero Energy Corporation, which accounted for approximately $11,831,000, or 17%, of our total consolidated revenues in 2003. We are not affiliated with Valero and believe that we could sell our crude oil to other purchasers should we lose Valero as a purchaser, though the terms might be less favorable.

Price Risk Management

We sometimes utilize commodity futures, over-the-counter swaps or similar derivatives to mitigate risks related to the volatility of oil and gas prices. Such transactions can also be used to protect against the risk of an expanding differential between NYMEX and Rocky Mountain gas prices, which can occur when Rocky Mountain gas supplies exceed regional demand and pipeline capacity out of the Rocky Mountain region or due to other factors, such as regional weather differences. A portion of these contracts did not meet all of the conditions required for utilization of hedge accounting, but were nevertheless viewed by us as providing considerable revenue protection in the event of declining oil or gas prices. See Item 7A, Quantitative and Qualitative Disclosures about Market Risk, below for additional disclosures relating to derivatives, including our open derivative positions as of February 27, 2004.

Title to Oil and Gas Properties

As is customary in the oil and gas industry, we typically conduct only a preliminary title examination at the time that we acquire leases of properties believed to be suitable for drilling operations. Prior to the commencement of drilling

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operations, however, we engage independent attorneys to conduct a thorough title examination of drill site tracts. Once production from a given well is established, a division order title report is prepared, which indicates the proper parties and percentages for payment of production proceeds, including royalties. We believe that titles to Prima s leasehold properties are good and defensible in accordance with standards generally acceptable in the oil and gas industry.

Oilfield Services

We conduct our oilfield services business under the names of Action Oilfield Services in Colorado and Action Energy Services in Wyoming.

Action Oilfield Services

Action Oilfield Services (AOS) has been active in the D-J Basin since 1986, operating out of a field office and yard near LaSalle, Colorado. AOS owns various well servicing equipment including eight completion rigs, a swab rig, tractor trailer rigs for water hauling, and oilfield rental equipment, such as pumps, tanks and blowout preventers. During 2003, we experienced high utilization rates for our people and equipment due to strong demand for services for well recompletions, re-works and drilling in the area. We intend to continue with our well servicing activities in the D-J Basin and will seek opportunities to profitably expand the business. AOS provides services for Prima as well as third-party operators in the area. During 2003, 22% of AOS s revenues were from activities performed for Prima. AOS fees and costs associated with providing services to Prima are eliminated in the consolidated financial statements. Third-party revenues recorded by AOS in 2003 totaled $6,718,000, or 9.6% of our consolidated revenues.

Action Energy Services

We formed Action Energy Services (AES) in the first quarter of 1999 to conduct CBM well drilling and servicing activities in the Powder River Basin. AES leases an office and yard in Gillette, Wyoming. AES has nine CBM drilling and service rigs and related equipment. During 2003, industry activity levels in the Powder River Basin CBM play were relatively modest, due largely to limited availability of drilling permits on federal lands caused, in part, by the pending status of the EIS early in the year and subsequent legal challenges to the EIS after the record of decision was published at the end of April 2003. As a result, we experienced moderate utilization rates for our people and equipment during the year. However, we believe that activity levels in the area will increase as the underlying causes of the slowdown are addressed and we intend to continue to conduct both drilling and well servicing operations in the Powder River Basin on behalf of both Prima and unaffiliated third parties. During 2003, 30% of AES s revenues were services conducted for Prima, and these revenues and the related costs have been eliminated in consolidation. AES s third-party revenues were $1,858,000 in 2003, accounting for 2.6% of our consolidated revenues.

Other Properties

We lease 15,840 square feet of office space in Denver, Colorado for our corporate headquarters, at an escalating annual cost averaging approximately $275,000 over the seven-year term that commenced December 1, 2000. We lease office space with a yard and shop facilities in Gillette, Wyoming on a month-to-month basis for use in our Powder River Basin oil and gas production and oilfield service operations. We own 160 acres of land in Weld County, Colorado with a shop, office building and yard facilities for use in our D-J Basin oil and gas production and oilfield service operations. At December 31, 2003, this land in Weld County had a net book value of $111,000 and the furniture and office equipment at these three locations had a combined net book value of $195,000.

We own approximately ten acres of surface land with no mineral rights on the western side of Greeley, Colorado. The land, which was acquired in March 2001 in exchange for minor undeveloped mineral rights, is part of a planned 760-acre commercial and office park development. We plan to hold this land, which had a net book value of $944,000 at the end of 2003, for future sale, exchange or development.

Prima is a 6% limited partner in a real estate limited partnership that owns approximately 22 acres of undeveloped land in Phoenix, Arizona for investment. The net book value of this partnership interest was $141,000 at December 31, 2003.

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Competition

All of the businesses in which we operate are highly competitive. Our oil and natural gas operations encounter strong competition from major oil and gas companies, independent operators and others. Competition is particularly intense with respect to the acquisition of desirable undeveloped and developed oil and gas properties. The principal competitive factors in the acquisition of oil and gas properties include the availability and quality of staff and data necessary to identify, investigate and purchase such properties, and the financial resources necessary to acquire and develop such assets. Many of our competitors have appreciably greater financial, technical and other resources and have more experience in the exploration for and production of oil and natural gas than we have.

Competition in oilfield services traditionally involves such factors as price, efficiency, condition of equipment, availability of labor and equipment, reputation and customer relations. Some of our competitors in the oilfield services business are substantially larger than we are and have appreciably greater financial and other resources. The competitive environment within which we operate is uncertain and extremely price oriented. Likewise, other businesses that we may participate in, including gas marketing and trading, and gas gathering and processing, are characterized by significant competition from companies with greater financial resources than Prima and, potentially, better information regarding markets than we have access to.

Regulation

Our businesses are subject to extensive federal, state and local laws and regulations on the exploration for and the development, production and marketing of oil and gas. Oilfield service operations are also subject to various types of regulation by state and federal agencies. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, and numerous federal and state departments and agencies are authorized by statute to issue rules and regulations binding on the oil and gas industry and its operators. The regulatory compliance burden on the oil and gas industry significantly impacts the cost of doing business, and failure to comply with regulations may carry substantial penalties. Under some circumstances, regulations may impose prohibitive costs that render development of an oil and gas property uneconomic or otherwise may impede development of a property. A partial overview of prominent regulations applying to oil and gas operations follows.

Drilling and Production Matters

States in which Prima conducts its gas and oil activities regulate drilling activities and the production and sale of natural gas and crude oil. Such regulations establish and implement requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources. In addition, states may regulate the rate of production and establish maximum daily production allowables for wells on a market demand or conservation basis. At times in the past, the federal government has regulated the prices at which oil and gas could be sold. Sales prices of oil and gas are not currently regulated, but there is no assurance that price controls will not be reinstituted in the future. Congress could re-enact price controls or other regulations in the future.

Environmental Matters

Prima is subject to extensive federal, state and local environmental laws and regulations that, among other things, regulate the discharge or disposal of materials or substances into the environment and otherwise are intended to protect the environment. Numerous governmental agencies issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial administrative, civil and/or criminal penalties and in some cases injunctive relief for failure to comply. Some laws, rules and regulations relating to the protection of the environment may, in certain circumstances, impose strict liability for environmental contamination. Such laws render a person or company liable for environmental and natural resource damages, cleanup costs and, in the case of oil spills in certain states, consequential damages without regard to negligence or fault.

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Other laws, rules and regulations may require the rate of oil and natural gas production to be below the economically optimal rate or may even prohibit exploration or production activities in environmentally sensitive areas. In addition, state laws often require some form of remedial action such as closure of inactive pits and plugging of abandoned wells to prevent pollution from former or suspended operations. Legislation has been proposed and continues to be evaluated in Congress from time to time that would reclassify certain oil and gas exploration and production wastes as hazardous wastes. This reclassification would make such wastes subject to much more stringent and expensive storage, treatment, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant adverse impact on operating costs for the oil and gas industry, including Prima. Initiatives to further regulate the disposal of oil and gas wastes are also proposed in certain states from time to time and may include initiatives at county, municipal and local government levels. These various initiatives could have a similar adverse impact on our operations. The regulatory burden on the oil and natural gas industry increases its cost and risk of doing business and consequently affects its profitability.

Compliance with these environmental requirements, including financial assurance requirements and the costs associated with the cleanup of any spill, could have a material adverse effect upon Prima s capital expenditures, earnings or competitive position. We believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on our competitiveness. Nevertheless, changes in environmental laws and regulations have the potential to adversely affect Prima s operations. For example, the federal Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), also known as the Superfund law, imposes liability, without regard to fault (i.e. strict and joint and several liability) or the legality of the original conduct, on certain classes of persons with respect to the release of a hazardous substance into the environment. These persons include the current or prior owner or operator of the disposal site or sites where the release occurred and companies that transported, disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for the federal or state government to pursue such claims. It is also not uncommon for neighboring landowners and other third parties to file claims for personal injury or property or natural resource damages allegedly caused by the hazardous substances released into the environment. Under CERCLA, certain oil and gas materials and products are, by definition, excluded from the term hazardous substances. However, certain federal courts have held that some wastes associated with the production of crude oil may be classified as hazardous substances under CERCLA.

Similarly, under the federal Resource, Conservation and Recovery Act of 1976, as amended (RCRA), which governs the generation, treatment, storage and disposal of solid wastes and hazardous wastes, certain exploration and production wastes are exempt from the definition of hazardous wastes. This exemption continues to be subject to judicial interpretation and increasingly stringent state interpretation. During the normal course of its operations, Prima generates or has generated in the past exempt and non-exempt wastes, including hazardous wastes that are subject to RCRA and comparable state statutes and implementing regulations. The federal Environmental Protection Agency (EPA) and various state agencies continue to promulgate regulations that limit the disposal and permitting options for certain hazardous and non-hazardous wastes.

The state of Colorado, where a significant portion of Prima s producing properties are located, amended its statute concerning oil and natural gas development in 1994 to provide the Colorado Oil & Gas Conservation Commission (the COGCC) with enhanced authority to regulate oil and gas activities to protect public health, safety and welfare, including the environment. The COGCC has implemented several rules pursuant to these statutory changes concerning groundwater protection, soil conservation and site reclamation, setbacks in urban areas and other safety concerns, and financial assurance for industry obligations in these areas. To date, these rule changes have not adversely affected Prima s operations, as the COGCC is required to enact cost-effective and technically feasible regulations. However, there can be no assurance that, in the aggregate, these and other regulatory developments will not increase the cost of operations in the future.

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Also in Colorado, a number of city and county governments have enacted oil and gas regulations. These ordinances increase the involvement of local governments in the permitting of oil and gas operations, and impose additional restrictions or conditions on the conduct of operations so as to reduce their impact on the surrounding community. Accordingly, these local ordinances have the potential to delay and increase the cost of drilling, refracing and recompletion operations.

In Prima s CBM gas production operations in the Powder River Basin, we typically bring naturally occurring groundwater to the surface as a by-product of the production of methane gas. Federal and state authorities regulate the disposition of this water. To-date, most of the water produced from Prima s wells has been discharged on the surface, in accordance with permits obtained in compliance with federal and state statutes and regulations. However, water disposal alternatives are currently under review by federal and state regulatory authorities and future development of properties in the area may require utilization of other methods. Implementation of such alternatives, potentially including but not limited to, construction of evaporation ponds near the well site and treatment of the water, could add delays and costs in developing and operating these properties. Prima may also explore on or acquire properties in other areas where disposal of produced water will be subject to regulation by federal and state authorities.

A significant portion of Prima s leasehold interests in the Powder River Basin in Wyoming, the Uinta Basin in Utah, and elsewhere in the Rocky Mountain region is federal acreage where mineral rights, and sometimes surface ownership as well, are managed by the Bureau of Land Management (the BLM). Drilling and development of federal minerals and construction activities on federal surface are subject to the National Environmental Policy Act (NEPA). The BLM has delayed drilling on a substantial portion of the federal oil and gas leases held by Prima, as well as those of other operators in these areas, pending completion of environmental impact statements or assessments under NEPA. Delays in obtaining access to these lands, and conditions imposed on development of the properties, may affect the value of Prima s reserves and prospects.

In some circumstances, our operations involve the use of gas-fired compressors to transport collected gas. Operation of these compressors is subject to federal and state regulations for the control of air emissions.

The Federal Water Pollution Control Act (FWPCA) imposes restrictions and strict controls regarding the discharge of produced waters and other oil and gas wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters. The FWPCA and analogous state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of oil and other hazardous substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. State water discharge regulations and the federal National Pollutant Discharge Elimination System permits applicable to the oil and gas industry generally prohibit the discharge of produced water, sand and some other substances into coastal waters. The costs to comply with zero discharges mandated under federal and state law have not had a material adverse impact on Prima s financial condition and results of operations. Some oil and gas exploration and production facilities are required to obtain permits for their storm water discharges. Costs may be incurred in connection with treatment of wastewater or developing storm water pollution prevention plans.

The Oil Pollution Act of 1990 (OPA) imposes regulations on responsible parties related to the prevention of oil spills and liability for damages resulting from spills in waters of the United States. A responsible party includes the owner or operator of an onshore facility, vessel or pipeline, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns strict, joint and several liability to each responsible party for oil removal costs and a variety of public and private damages, including natural resource damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation, or if the party fails to report a spill or to cooperate fully in the cleanup. Even if applicable, the liability limits for onshore facilities require the responsible party to pay all removal costs, plus up to $350 million in other damages. Few defenses exist to the liability imposed by

OPA. Failure to comply with ongoing requirements or inadequate cooperation during a spill event may subject a responsible party to administrative civil or criminal enforcement actions.

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Operating Hazards and Insurance

The oil and natural gas business involves a variety of operating risks, including fires, explosions, blowouts, environmental hazards and other potential events that could adversely affect our ability to conduct operations or cause us to incur substantial losses. Such impairment or losses could reduce or eliminate funds available for exploration, exploitation or acquisitions, or result in loss of properties. In accordance with customary industry practices, we maintain insurance against some, but not all, potential risks and losses. We do not carry business interruption insurance. For some risks, we may elect not to obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable at a reasonable cost. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect us.

Employees and Offices

As of December 31, 2003, we had 146 full-time employees, including 40 in our Denver office and 106 in district and field offices. Of the district and field employees, 22 were employed in Prima s lease and well management operations and 84 were employed with our oilfield service operations. We also contract for the services of independent consultants involved in land, geology, engineering, accounting, regulatory affairs, and other disciplines as needed. We believe that Prima s relations with its employees are good. Prima s principal executive offices are located at 1099 18th Street, Suite 400, Denver, Colorado 80202.

Available Information

Our website address is www.primaenergy.com. We make available free of charge through our internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed with or furnished to the SEC under applicable securities laws as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. Our website information is not incorporated by reference into this Annual Report on Form 10-K.

Cautionary Statement for the Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995

We are including the following cautionary statement to take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statement made by, or on behalf of, Prima. The factors identified in this cautionary statement are important factors (but not necessarily all of the important factors) that could cause actual results to differ materially from those expressed in any forward-looking statement made by, or on behalf of, Prima. Where any such forward-looking statement includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that, while we believe such assumptions or bases to be reasonable and make them in good faith, assumed facts or bases almost always vary from actual results, and the differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, Prima or its management expresses an expectation or belief as to the future results, such expectation or belief is expressed in good faith and believed to have a reasonable basis, but there can be no assurance that the statement of expectation or belief will result, or be achieved or accomplished. We do not undertake to update, revise or correct any of the forward-looking information. Taking into account the foregoing, the following are identified as important risk factors that could cause actual results to differ materially from those expressed in any forward-looking statement made by, or on behalf of, Prima:

Volatility of Oil and Natural Gas Prices**.** Historically, oil and natural gas prices have been volatile and are likely to continue to be volatile. Prices are affected by, among other things, market supply and demand factors, market uncertainty, and actions of the United States and foreign governments and international cartels. These factors are beyond our control. To the extent that oil and gas prices decline, our revenues, cash flows, earnings and operations are adversely impacted. Further, in adversely affecting our cash flows and access to capital, low oil and gas prices could reduce our ability to replace production and grow. Because of the dynamism of, and number of influences on, commodity markets, we cannot accurately predict future oil and natural gas prices.

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Uncertainty of Oil and Natural Gas Reserve Estimates. Estimates of our proved reserves and related future net revenues are based on engineering reports prepared by our engineers and audited by independent engineers. These estimates are based on several assumptions that the Securities and Exchange Commission requires oil and natural gas companies to use, including that oil and natural gas prices in effect as of the end of the year remain constant. Such estimates are inherently imprecise indications of future net revenues. Actual future production, revenues, production taxes, operating expenses, and development costs may vary substantially from estimates. In addition, our reserves might be subject to upward or downward adjustment based on future production, results of future exploration and development, prevailing oil and natural gas prices and other factors.

Risks of Oil and Natural Gas Exploration, Development and Production. The search for oil and natural gas often results in unprofitable efforts, not only from dry holes, but also from wells that, though productive, do not produce oil or natural gas in sufficient quantities to return a profit on the costs incurred. No assurance can be given that our exploration, development and acquisition activities in the future will result in the addition of any oil or natural gas reserves that will be commercially productive. In addition, the costs of drilling, completing and operating wells are often uncertain, and drilling may be delayed or canceled as a result of many factors, including unacceptably low oil and natural gas prices, availability of drilling rigs, oil and natural gas property title problems, government regulation, inclement weather conditions and financial instability of third-party operators and working interest owners.

Need to Replace Reserves. Our future success depends to a significant degree upon our ability to continue to find, develop or acquire additional oil and gas reserves that are economically recoverable. Unless we replace the reserves that we produce through successful exploration, exploitation or acquisition, our proved reserves will decline. Additionally, approximately 30% of our total proved reserves at December 31, 2003 were undeveloped. Recovery of such reserves will require significant capital expenditures and successful drilling and/or recompletion operations. There can be no assurance that we will be successful in our future efforts to develop our proved reserves or replace our production.

Acquisitions Risks. We continually evaluate opportunities for property or corporate acquisitions that could enhance our business. Acquisitions of properties or companies involve assessments of several factors, including recoverable reserves, future oil and gas prices, future capital and operating costs, and potential environmental and other liabilities. Such assessments incorporate estimates and projections that are inherently imprecise and uncertain. In connection with any future acquisitions, we would intend to perform a review of the subject properties consistent with industry practices. However, such review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every property and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. While it is our current intention to continue to concentrate on acquiring properties with development, exploitation and exploration potential located in our core operating areas, we cannot assure you that in the future we will not decide to pursue acquisitions or properties located in other geographic regions. To the extent that such acquired properties are substantially different than our existing properties, our ability to efficiently realize the economic benefits of such transactions may be limited. We may not be able to successfully integrate future property or corporate acquisitions. We seek to make selective niche acquisitions of oil and gas properties, and we will pursue corporate acquisitions that we believe will be accretive. However, integrating acquired properties and businesses involves a number of special risks. These risks include the possibility that management may be distracted from normal business concerns by the need to integrate operations and systems and in retaining and assimilating additional employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results.

Dependence On Transportation Facilities Owned by Others. Our business depends on transportation facilities owned by others. The marketability of our oil and gas production, and the net prices received for such production, depend in part on the availability, proximity and capacity of pipeline systems or processing facilities owned by third parties. The unavailability of, or lack of available capacity on, these systems and facilities could result in curtailment of production, the delay or discontinuance of development plans for properties, and/or reduced price realizations for production. Although we have some contractual control over the transportation of our product, material changes in these business relationships or market conditions could significantly affect our operations. Federal and state regulation of oil and gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

Derivatives. Part of Prima s business strategy is to periodically use commodity futures contracts, including price and basis swaps, collars and options, to mitigate the impact of the volatility of oil and natural gas prices on a portion of our production and gas marketing activities. In certain circumstances, significant reductions in production caused by unforeseen events, or insufficient correlation between a derivative and the market prices that we receive for our production, could require us to make payments under such agreements even though such payments are not offset by revenues from production. To reduce these risks, we generally enter into derivatives for only a portion of our projected production and utilize derivatives closely correlated with our price realizations unless we believe market conditions to fix basis spreads are unfavorable. At times, however, we may decide to enter into derivatives contracts for volumes that match or exceed our projected total production, or contracts that increase, rather than decrease, our exposure to a decline in oil and gas prices or expansion of basis differentials. We would consider establishing such positions if our analyses lead us to believe that prices are likely to move in a manner that would generate gains from the positions. Derivative positions for volumes greater than our expected production, or which would increase our exposure to a decline in oil and gas prices or expansion of basis differentials, would be speculative and would be limited in size to an amount that, in management s judgment would not be material to our balance sheet taken as a whole, but they might have a significant positive or negative impact on reported net earnings.

Derivatives positions might also prevent Prima from receiving the full advantage of increases in oil or natural gas prices, and could expose us to risk of financial loss should a counterparty to one or more of our derivatives contracts fail to perform. The terms of our hedging agreements may also require that we furnish cash collateral, letters of credit or other forms of performance assurance in the event that mark-to-market calculations result in settlement obligations by us to the counterparties. Such performance assurance could encumber our liquidity and capital resources. In accordance with Statement of Financial Accounting Standards (SFAS) No. 133, we record the fair market value of each derivative position as an asset or liability. Changes in the fair market value of our derivatives positions could result in significant fluctuations in net income and stockholders equity from period to period.

Capital Requirements. We anticipate continuing to make substantial expenditures to find, develop, acquire and produce oil and gas reserves. We expect to have sufficient cash provided by operating activities and from available net working capital to fund planned capital expenditures in 2004. However, we have not established a line of credit to provide additional capital to respond to new opportunities. While we believe that we could arrange for borrowings or issuance of securities to fund such opportunities, should lower oil and gas prices or operating difficulties result in our cash flow from operations being less than expected or if capital markets were to deteriorate, we may be unable to obtain additional funds to expand our business.

Demand For Oilfield Services. Our oilfield services operations are dependent on the level of demand in our operating markets. Both short- and long-term trends in oil and gas prices affect demand. Because oil and gas prices are volatile, the level of demand for our services can also be volatile. Although we utilize our service companies in our oil and gas operations, the substantial majority of the demand for their services is dependent on third parties. In addition to oil and gas prices, other factors that can influence activity levels for our oilfield service operations include competition, our reputation, availability of labor, and weather. Further, activity levels in the areas in which we operate can be impacted by the attractiveness of oil and gas investment opportunities in the area relative to other oil and gas investment opportunities.

Competition. We compete with numerous other companies and individuals in virtually all facets of our business, including many that have significantly greater resources than we do. Such competitors may be able to pay more than Prima for desirable assets and experienced personnel. Many competitors may also have greater technical resources and increased staff to evaluate and develop investment opportunities than do we. Domestic oil and gas companies must also compete with imported oil and natural gas, coal, nuclear energy, hydroelectric power and other forms of energy.

Operating Hazards and Uninsured Risks. The oil and gas business involves a variety of operating risks, including risks of fire, explosions and well blow-outs, as well as risks associated with production, marketing, and general economic conditions. We maintain insurance against some, but not all, of these risks, any of which could result in substantial losses. There can be no assurance that insurance carried would be adequate to cover any losses or exposure to liabilities. There also can be no assurance that in the future insurance will continue to be available at premium levels that justify its purchase, or whether it will be available at all.

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Government Regulation. Federal, state and local governments extensively regulate all aspects of the oil and gas industry. Regulations govern such things as drilling permits, environmental protection and pollution control, spacing of wells, the unitization and pooling of properties, water use and disposal, production, royalty rates and various other matters including taxation. As an example, our exploration and development plans for Powder River Basin CBM properties are dependent to a significant degree upon receipt of drilling permits from the federal Bureau of Land Management. On April 30, 2003, the BLM issued a final Record of Decision in relation to its Environmental Impact Statement regarding future CBM drilling in the Powder River Basin. We have filed permit applications for approval by the BLM under the terms of the new EIS, but cannot predict whether or when such permits will be granted. Another instance of governmental regulatory oversight affecting Prima is the Wyoming Department of Environmental Quality s responsibility for considering applications for water discharge permits. Permits to discharge water on the surface had generally been attainable early in development of CBM in the Powder River Basin, but it is expected that, in the future, the Wyoming DEQ will generally require water management techniques other than surface discharge, such as collection in containment reservoirs or treating, which would increase development and operating costs. Additionally, the Colorado Oil & Gas Conservation Commission has promulgated regulations to protect ground water, conserve soil, provide for site reclamation, ensure setbacks in urban areas, generally promote safety concerns and mandate financial assurance for companies in the industry. Oil and gas industry legislation and administrative regulations are periodically changed for a variety of political, economic and other reasons. These regulations may substantially increase the cost of doing business and sometimes prevent or delay the commencement or continuance of any given exploration or development project and may adversely affect the economics of capital projects. At the present time, we cannot predict what effects current and future proposals or changes in existing laws or regulations will have on operations, estimates of oil and natural gas reserves, or future net revenues. The costs of complying, monitoring compliance and dealing with the agencies that administer these regulations can be significant. We could also be subject to substantial penalties if we fail to comply with any regulation.

Environmental Regulation. Our operations are subject to complex and frequently changing environmental laws and regulations adopted by federal, state and local governmental authorities. New laws or regulations, or changes to current practices, could have a material adverse effect on our business. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. We could face significant liabilities to the government and third parties for discharges of oil, natural gas or other pollutants into the air, soil or water, and we might need to spend substantial amounts on investigations, litigation and remediation. We could face material indemnity claims with respect to properties we own or have owned. We cannot be sure that existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced or altered in the future, will not materially adversely affect our results of operations and financial condition.

Key Personnel. We depend on the continued services of our executive officers and other key employees. Loss of the services of any of these people could have a material adverse effect on our operations. We currently do not have employment agreements with any of our key employees, including Richard H. Lewis, who serves as Prima s Chief Executive Officer, President and Chairman of the Board of Directors.

ITEM 3. LEGAL PROCEEDINGS

We are a party to various legal proceedings arising in the ordinary course of its business. As of the date of the filing of this report, none of these is expected to have a material adverse impact on our financial position or results of operations.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of our security holders during the quarter ended December 31, 2003.

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PART II

ITEM 5. MARKET FOR THE REGISTRANT S COMMON STOCK AND RELATED STOCKHOLDER MATTERS

(a) Market Information Prima s common stock trades on the Nasdaq National Market under the symbol PENG. The following table sets forth the Nasdaq high and low sales prices for our common stock for each quarterly period during the years ended December 31, 2003 and 2002.

Year Ended December 31, 2003	HIGH	LOW
Quarter Ended December 31, 2003	$37.50	$25.38
Quarter Ended September 30, 2003	27.01	20.47
Quarter Ended June 30, 2003	24.30	18.02
Quarter Ended March 31, 2003	24.00	18.27
Year Ended December 31, 2002		
Quarter Ended December 31, 2002	$24.49	$20.38
Quarter Ended September 30, 2002	23.00	15.70
Quarter Ended June 30, 2002	26.34	20.23
Quarter Ended March 31, 2002	26.46	19.10

The above quotations are from sources believed to be reliable. They do not include any retail mark-ups, mark-downs or commissions and may not represent actual transactions. On February 27, 2004, the closing sale price for our common stock was $33.79 per share.

(b) Holders of Record Our common stock holders of record at February 27, 2004 totaled 794.

(c) Dividends Holders of common stock are entitled to receive such dividends as may be declared by our Board of Directors. No cash dividends were declared or paid in 2003, 2002 or 2001. Future cash dividends, if any, will be evaluated based, among other things, on our operating results, capital requirements and financial condition at the time.

(d) Securities Authorized for Issuance Under Equity Compensation Plans The following table includes information regarding Prima s equity compensation plans as of the year ended December 31, 2003:

	(a)	(b)	(c)
	Number of securities	Weighted-average	Number of securities remaining available for future issuance under equity

Plan Category	to be issued upon exercise of outstanding options, warrants and rights	exercise price of outstanding options, warrants and rights	compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	979,075	$ 17.51	1,070,125
Equity compensation plans not approved by security holders			
Total	979,075	$ 17.51	1,070,125

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ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth a summary of selected consolidated financial data. This data should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and the Consolidated Financial Statements and notes thereto.

	Years Ended December 31,				
	2003	2002	2001	2000	1999
	(in thousands, except per share amounts)				
Income Statement Data:					
Revenues:					
Oil and gas sales	$ 58,622	$ 25,785	$ 44,548	$ 44,437	$20,644
Gains (losses) on derivative instruments, net	2,320	(2,918)	6,435		
Oilfield services	8,577	8,326	8,090	6,278	4,974
Trading revenues					2,318
Interest, dividend and other	635	597	1,214	1,464	1,286
	70,154	31,790	60,287	52,179	29,222
Expenses:					
Depletion of oil and gas properties	14,956	9,710	9,190	6,150	4,650
Depreciation of other property	1,058	1,088	1,039	1,054	817
Lease operating expense	3,619	3,076	3,295	2,623	2,012
Ad valorem and production taxes	5,783	2,116	3,344	3,421	1,765
Oilfield services	6,510	6,490	5,812	4,585	3,377
General and administrative	3,321	3,255	3,559	2,916	1,712
Impairment of natural gas swap			241		
Trading costs					2,827
	35,247	25,735	26,480	20,749	17,160
Income before income taxes and cumulative effect of change in accounting principle	34,907	6,055	33,807	31,430	12,062
Provision for income taxes	11,515	825	10,650	9,535	3,035
Net income before cumulative effect of change in accounting principle	23,392	5,230	23,157	21,895	9,027

Cumulative effect of change in accounting principle	403		611		
Net income	$ 23,795	$ 5,230	$ 23,768	$ 21,895	$ 9,027
Basic net income per share before cumulative effect adjustment	$ 1.82	$ 0.41	$ 1.82	$ 1.72	$ 0.70
Cumulative effect adjustment	0.03		0.05		
Basic net income per share	$ 1.85	$ 0.41	$ 1.87	$ 1.72	$ 0.70
Diluted net income per share before cumulative effect adjustment	$ 1.79	$ 0.40	$ 1.75	$ 1.65	$ 0.69
Cumulative effect adjustment	0.03		0.05		
Diluted net income per share	$ 1.82	$ 0.40	$ 1.80	$ 1.65	$ 0.69
Balance Sheet Data (end of period):					
Total assets	$177,217	$141,927	$135,444	$104,900	$72,665
Net property and equipment	106,132	93,377	96,005	70,597	44,467
Long-term debt					
Stockholders equity	130,676	107,266	101,740	80,298	58,908
Working capital	56,148	35,954	28,122	25,678	21,408

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This Item 7 contains forward-looking statements which are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. These statements include, without limitation, statements relating to liquidity, financing of operations, continued volatility of oil and natural gas prices, estimates of future production and net cash flows attributable to proved reserves, future expenditures, and other such matters. The words anticipates, believes, expects, intends or estimates and similar expressions identify forward-looking statements. Prima does not undertake to update, revise or correct any of the forward-looking information. Readers are cautioned that such forward-looking statements should be read in connection with Prima s disclosures under the heading: Cautionary Statement for the Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995.

The following discussion is intended to assist in understanding our financial position and results of operations for the three-year period ended December 31, 2003. The Consolidated Financial Statements and notes thereto should be referred to in conjunction with this discussion.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operation are based upon the information reported in our consolidated financial statements. The preparation of these financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our decisions on historical experience and various other sources that are believed to be reasonable under the circumstances, but actual results may differ from our estimates due to changing business conditions or unexpected developments. Policies and estimates that we believe are critical to understanding our business operations and results of operations are detailed below. For additional information on our significant accounting policies, see Notes to Consolidated Financial Statements, particularly Note 1.

Estimates of Proved Oil and Gas Reserves Reserves evaluation is a subjective process of estimating underground accumulations of oil and gas that cannot be directly measured and the economic recoverability of such reserves. There are significant uncertainties inherent in the process, and the accuracy of any reserve estimate is a function of the quality of available data, and of the engineering and geological interpretations and judgments made. Estimates of economically recoverable oil and gas reserves and related future net cash flows necessarily depend upon a number of variable factors and assumptions, such as projected oil and gas prices, operating costs, severance taxes and development costs, all of which may in fact vary considerably from actual future results. Any significant change in these assumptions, or variances from projected well performance, could materially affect the estimated quantity and value of proved reserves, which could affect the carrying value of Prima s oil and gas properties and the amount of depletion expense recorded as reserves are produced and sold. Estimated reserves attributed to undeveloped locations are particularly sensitive to changes in assumptions based on new data from analogous properties or adjustments to projected future prices or costs. Actual production, revenues and expenditures with respect Prima s reserves will likely vary from estimates and such variances may be material.

Full Cost Method We use the full cost method of accounting for our oil and gas activities. Under this method, all costs incurred in the acquisition, development and exploration of oil and gas properties are capitalized into cost centers that are established on a country-by-country basis (we have a single cost center for the United States). Such amounts include the costs of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals, and pre-production operating costs incurred while de-watering CBM wells. Capitalized costs also include salaries, employee benefits, costs of consulting services and other expenses that are directly related to acquisition, development and exploration activities. Costs associated with production and general corporate activities are expensed in the period incurred.

Full Cost Ceiling Limitation Under the full cost method, we are subject to quarterly calculations of a limitation, or ceiling, on the amount that can be capitalized on our balance sheet for oil and gas properties. If net capitalized costs

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exceed the cost center ceiling, a writedown in the carrying value of the properties must be recorded in the amount of the excess. If required, such a non-cash charge would reduce earnings in the period of occurrence but would result in lower depletion expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and requires subjective judgments. Given the volatility of oil and gas prices, it is likely that our estimate of discounted present value of future net cash flows from proved reserves will change in the future. If oil and gas prices decline, even if only for a short period of time, or if we have downward revisions to our estimated proved reserves, it is possible that writedowns of our oil and gas properties could occur. While the quantities of proved reserves require substantial judgment, the assumptions for future prices of oil and gas that are used to calculate the present value of future cash flows from proved reserves do not require judgment. Rules generally prescribe that the ceiling test calculation be based on oil and gas prices in effect as of the balance date of the ceiling test, held constant in the future, and are not based on our assessment of future prices. Under certain circumstances, however, improvements in prices shortly after the balance sheet date of a ceiling test may be utilized to avoid recording a writedown that would otherwise be required.

Unevaluated Costs   Costs associated with unevaluated leasehold acreage and wells that have not yet been determined to be economically productive or non-productive are not initially included in our amortization base. Leasehold and associated costs are either transferred to our amortization base with the costs of drilling related wells or are assessed quarterly for possible impairment or reduction in value, with costs transferred to the amortization base if estimated fair value is below cost. The decision to withhold costs from amortization and the timing of transferring such costs into the amortization base involves a significant amount of judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics, results of nearby drilling, and recent transactions involving acreage in the area.

Other Property and Equipment   Oilfield service equipment and other property and equipment are carried at cost. Renewals and betterments are capitalized, while repairs and maintenance are expensed. Capitalized costs are depreciated using the straight-line method over the estimated useful lives of the assets. The carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including disposal value if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. Changes in such estimates could result in a reduction in the carrying value of our property and equipment.

Asset Retirement Obligations   Our asset retirement obligations (ARO) primarily represent the estimated present value of amounts we project will be incurred to plug, abandon and remediate our oil and gas properties at the end of their productive lives, in accordance with currently applicable laws and regulations. Statement of Financial Accounting Standards No. 143, which we adopted effective January 1, 2003, requires that an obligation to retire a tangible long-lived asset be recognized as a liability in the period in which it is incurred and becomes determinable, with an offsetting increase in the carrying amount of the associated asset. The fair value of the ARO is measured using expected future cash outflows discounted at an estimated credit-adjusted risk-free interest rate applicable to Prima. The cost of the tangible asset, including the initially recognized ARO, is reflected in the computation of depletion expense relating to our oil and gas properties. In addition, accretion expense is recognized over time, as the discounted ARO liability is accreted to its expected settlement cost. Inherent in the present value calculation of ARO are numerous assumptions and estimates, including ultimate settlement amounts, settlement timing, inflation factors, and applicable discount rates. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance.

Recognition of Oil and Gas Sales Revenue We derive a significant portion of our revenue from the sale of produced natural gas and crude oil. We record revenue in the month in which production is delivered to a purchaser, based on estimates of sales volumes and the applicable unit prices. Purchaser remittances are generally received between 20 and 40 days after the end of the month in which production occurs, but can take longer for properties operated by other operators or initially for new wells. We use our knowledge of our properties, including historical performance, plus published spot market prices and other data, as the basis for our estimates of oil and gas sales revenue. Because we operate virtually all of our significant producing oil and gas properties, we generally have certain gross production data available on a timely basis for wells that account for most of our production. Such field data generally provide reasonably reliable approximations of sales volumes, subject to adjustments for fuel use, metering variances, and other factors. As such, variances between our estimated sales volumes and actual amounts sold have historically been modest. Estimated unit prices are frequently determinable, or can be closely estimated, at the time production is delivered or shortly thereafter. In instances where the price we receive for gas production is determined by percentage-of-proceeds contracts (such as for our D-J Basin wells), our realized prices are dependent on sales prices received for dry gas and natural gas liquids by the operator of the liquid extraction plants and our estimates are prone to increased error, but these have also generally been modest in the past except during periods of exceptional short-term price volatility. All adjustments for differences between estimated and actual sales volumes or prices are recorded in the period in which such variances are discovered through receipt of payment or other data.

Fair Value of Derivative Instruments We periodically enter into derivatives contracts, primarily for the purpose of mitigating risks related to the prices we will receive for future oil and gas production. The fair value of these derivatives can be very volatile, primarily due to the high volatility of the underlying commodity prices. The estimated fair values of derivative instruments are recorded on our consolidated balance sheets. For derivatives that don t qualify for hedge accounting treatment, changes in fair value are recorded as gains or losses in the income statement as they occur. For instruments that qualify for hedge accounting treatment, changes in fair value net of related income taxes are recorded directly to stockholders equity until the hedged production is sold, at which time realized gains or losses are included in reported oil and gas sales revenue. In determining the amounts to be recorded before derivatives positions are settled, we must estimate the fair values of such contracts. Our estimates are based upon various factors, including contract settlement dates, specified volumes and prices, quoted closing prices on the NYMEX or over-the-counter and, where applicable, volatility and the time value of options. For fixed-price contracts, such prices are compared to futures prices estimated as of the valuation date, and the resulting projected future cash inflows or outflows are discounted to calculate the fair value of the derivative positions. The calculation of the fair value of collars and floors may require the use of the Black-Scholes option-pricing model, although market quotations are used to establish fair value when available. We frequently validate our valuation estimates using independent third party quotations.

Depletion The capitalized costs of our evaluated oil and gas properties, plus estimated future capital costs related to our proved reserves, are amortized on a unit-of-production method based on our estimate of total proved reserves. The quantities of estimated proved oil and gas reserves and amounts of future development costs are significant components of amortization, and revisions in such estimates would alter the amount of depletion expense recorded per unit of production. In the absence of offsetting changes to estimates, if estimated reserve volumes increase or decrease, then the amortization rate per unit of production will change inversely; however, when estimated future capital costs change, the amortization rate moves in the same direction.

Income Taxes We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared. We, therefore, estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating loss carryforwards. Any differences between estimates we initially used and amounts subsequently determined to be appropriate are recorded in the period in which our estimate is revised.

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Liquidity and Capital Resources

Our principal sources of liquidity have been internal generation of cash flow from operations, proceeds from occasional asset sales, and existing net working capital. Additional potential sources of capital include borrowings and issuances of common stock or other securities.

Net cash provided by operating activities totaled $46,149,000 in 2003, compared to $21,524,000 in 2002 and $43,008,000 in 2001. Our net working capital increased from $35,954,000 at the end of 2002 to $56,148,000 on December 31, 2003. Our cash equivalents and short-term investments also increased in 2003, from $38,007,000 at the beginning of the year to $57,192,000 at the end of 2003. Prima had no outstanding long-term debt, capital lease agreements or guarantees at either date. Our operating lease agreements, and other commitments and contingencies, are disclosed in Note 8 of the Notes to Consolidated Financial Statements.

Prima s revenues and cash flows are substantially derived from oil and gas sales, which are dependent on oil and gas sales prices and production volumes. Historically, oil and gas sales prices have been volatile and our average price realizations in 2003 were 56% higher, on an Mcfe basis, than in 2002. Combined with a 46% increase in net production volumes, these improved prices led to a 127% growth in Prima s oil and gas sales revenue from 2002 to 2003, from $25,785,000 to $58,622,000, including hedging effects. The increase in our oil and gas sales revenue was the primary factor accounting for higher earnings and cash flow in 2003. Prima s future revenues will continue to be significantly affected by volatility in oil and gas prices. As further discussed below, prices for oil and Rocky Mountain natural gas to-date in 2004 and as reflected in futures markets for the balance of the year are modestly higher than in 2003, and we are projecting an increase of up to 5% in Prima s net production volumes.

Our capital investments on oil and gas properties totaled $26,856,000 during 2003, compared to $22,252,000 in 2002 and $35,248,000 in 2001. During 2003, we expended $12,409,000 for exploitation and development of properties in the D-J Basin, $8,506,000 for costs incurred on Powder River Basin CBM properties, $3,016,000 for exploration and development of other properties, $801,000 for acreage costs, and $2,124,000 of capitalized overhead. Additional uses of funds in 2003 included $1,422,000 for other fixed assets, predominantly oilfield service equipment and facilities, and $815,000 for treasury stock repurchases net of proceeds from stock option exercises.

Excluding acquisitions, Prima s preliminary plans for 2004 provide for capital investments of approximately $45 million. Our current projected allocation for these capital investments is approximately as follows: $14 million for development of properties in the D-J Basin; $24 million for exploitation of CBM properties in the Powder River Basin; and $7 million for other costs, including higher-risk exploration activities, acreage acquisitions, oilfield services equipment, and capitalized overhead. This budget is preliminary and may be adjusted upward or downward in response to new developments during the year.

Expected 2004 activities include: drilling approximately 35 wells and re-fracturing or re-completing approximately 50 wells in the D-J Basin; drilling an estimated 150 CBM wells in the Powder River Basin and hooking up most of these and 130 previously-drilled CBM wells; participation in up to six wells in the Cave Gulch area; and continued exploratory operations on Prima s Coyote Flats Prospect in Utah and the Merna Prospect in the Green River Basin. A test well may also be initiated this year on the Christmas Meadows prospect in the Table Top Unit, along the Overthrust Belt in northeastern Utah. These activities are dependent on securing drilling permits and other required regulatory approvals, among other factors.

The CBM activities planned for 2004 include additional drilling to further develop the Porcupine-Tuit field, which currently produces from a relatively shallow Wyodak coal, and operations to evaluate and develop deeper unproved coals within our Kingsbury, Cedar Draw, North Shell Draw and Wild Turkey project areas. We anticipate that these deeper coals will need to be de-watered for a period of time, perhaps a year or more, before significant gas production rates are established. As a result, these activities may not generate significant additions to proved reserves in the current year, but

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if our expectations are met they would be expected to result in additions to proved reserves and increased production over the following two to three years.

We intend to fund these planned capital investments with cash flow from operations and available working capital. Our expectations as to cash provided by operating activities are predicated on projections of oil and gas production volumes and oil and gas prices, among other factors. Although not budgeted, we also continue to seek acquisitions that we believe will enhance our existing businesses. An acquisition could be consummated using cash reserves, bank borrowings, and/or through issuance of debt or equity securities.

Without contributions from new exploration or acquisitions, we are projecting that our current year oil and gas production will total between 15.6 Bcfe and 16.1 Bcfe, which compares to 15.4 Bcfe in 2003. Approximately 40% of current year production is projected to come from Powder River Basin CBM properties. Most of this is expected to be derived from currently producing Porcupine-Tuit wells that will exhibit depletion-related declines during the year. Contributions from new wells in the Powder River Basin are expected to begin during the third quarter and increase as de-watering occurs. Overall, excluding acquisitions or discoveries, Prima s net production is projected to decline during 2004 until late in the year when production from new CBM wells is expected to ramp up.

Natural gas is currently expected to account for more than 80% of Prima s total oil and gas production in 2004. Gas prices have been strong during the past several months in response to a number of factors, including recent declines in North American natural gas production and relatively high prices for oil, which can be substituted for natural gas in some applications if economically advantageous.

As of February 27, 2004, average prices for the 2004 CIG monthly index that have been published (January through March) plus the average of the quoted prices for the remainder of 2004 CIG contract months in over-the-counter futures markets combine to average $4.76 per MMBtu of natural gas. These compare to the average closing prices for the CIG monthly index during 2003 of $4.04 per MMBtu of natural gas. There is no assurance, however, that prices reflected in futures markets will actually be realized, except to the extent that fixed price or hedging contracts are entered into.

As of the close of business on February 27, 2004, we had open contracts for forward sales of 700,000 MMBtu of natural gas per month for the months of April 2004 through October 2004, at an average NW Rockies (Opal location) price of $4.41 per MMBtu. An additional 350,000 MMBtu of natural gas have been forward-sold for November 2004, at an average CIG price of $4.00 per MMBtu. Both of these indices are highly correlated with changes in Prima s net well-head price realizations and are expected to represent effective hedges. With respect to crude oil, as of February 27, 2004 we had entered into forward-sale NYMEX contracts covering a total of 95,000 barrels applying to the contract months of April through September 2004, at an average price of $31.27 per barrel. These are also assessed as effective hedges. Combined, these positions total approximately 5,820,000 Mcfe of volumes relating to the balance of 2004. Prima has realized net losses totaling $442,000 on effective and ineffective hedging contracts closed for the months of January through March 2004.

In 2001, Prima s Board of Directors approved a repurchase program of up to 5% of our common stock then outstanding, or approximately 640,000 shares. As of December 31, 2003, approximately 291,000 shares remained subject to repurchase under this authorization.

Results of Operations

As noted, our primary source of revenues is the sale of oil and natural gas production. Because of significant fluctuations in oil and natural gas prices and variances in production volumes, our operating results for any period are not necessarily indicative of future operating results. Oil and gas prices have historically been volatile and are likely to continue to be volatile. Prices are affected by, among other things, market supply and demand factors, market uncertainty, and actions of the United States and foreign governments and international cartels. These factors are beyond our control. Our revenues, cash flows, earnings and operations are adversely affected when oil and gas prices decline. Natural gas has typically represented approximately 80% of our total oil and gas production mix. After reaching record high levels early in 2001, gas prices declined significantly until early 2003 when prices again approached record levels, and prices have generally remained at favorable levels into 2004. These price movements have significantly impacted our operating results, as more fully described below. We cannot accurately predict future oil and natural gas prices, but historically oil and gas supply and demand have responded to changes in price levels to correct from short-lived extreme levels of high or low prices.

In addition to factors affecting global or national markets for oil and natural gas, our business is subject to regional influences on natural gas markets. Gas production in the Rocky Mountain area, where Prima s producing properties are located, generally exceeds regional consumption needs and the surplus is transported via pipelines to other markets. Rocky Mountain gas has typically sold for a lower price than gas produced in the Gulf Coast region or in areas closer to major consumption markets that rely on gas delivered from outside the region. The size of the discount has varied widely based on seasonal factors, structural factors, and other supply and demand influences. From 1991 through 2003, CIG gas prices have averaged approximately $0.65 per MMBtu less than the average for gas at Henry Hub, but the amount of this discount has ranged on an annual basis between $0.26 (1999) and $1.40 (2003), and monthly variances in index prices have ranged between an $0.11 premium (January 1993) and a $4.27 discount (March 2003). Basis differentials widened considerably beginning in May 2002, resulting in depressed regional prices for Rocky Mountain gas for several months despite relatively strong gas prices in other areas of the country. In early 2003, Rocky Mountain gas prices improved but basis differentials remained wide, as prices in other regions increased as much or more. Beginning in May 2003, when significant expansions in pipeline capacity were completed and placed in service, basis differentials began to significantly narrow. NYMEX-versus-CIG differentials during the four calendar quarters of 2003 averaged sequentially $2.82, $1.51, $0.81 and $0.47, and recent forward market quotes indicate expectations of average differentials during the next year of approximately $0.70 to $0.80. Future basis differentials, which we expect to have an important impact on our operating results, may vary substantially from the current indications on futures markets due to a number of factors, including but not limited to, the timing, size and location of pipeline expansions and the timing, size and location of changes in regional gas deliverability.

Since historically most of Prima s revenues have been derived from oil and gas sales, our profitability has been primarily determined by oil and gas production volumes and average margins realized per unit of production. Oil and gas prices, over which we have little control, can vary significantly from period to period and are a key determinant of profitability. We also look at all of our costs, other than those directly related to oilfield service operations, on a per-Mcfe basis. Our average prices and costs per Mcfe for the last three years are summarized in a table below. Generally, on a per unit basis: ad valorem and production taxes have varied with the level of oil and gas prices, at 8% to 10%; lease operating expenses have been relatively stable, at $0.24 to $0.29 per Mcfe; and general and administrative expenses have varied inversely with production volumes, ranging from $0.22 to $0.31 per Mcfe. The remaining cost that we consider in measuring margins for oil and gas production is depletion expense, which represents the average per-unit capital investment for our proved oil and gas reserves, including net costs incurred to-date plus estimated future development costs related to such proved reserves. Depletion expense has increased during the past three years, from an average $0.77 per Mcfe in 2001 to $0.96 per Mcfe in 2003, including $1.05 per Mcfe in the fourth quarter of the year based on year-end estimated proved oil and gas reserves. These increases reflect higher finding and development costs than our earlier historical average, including higher estimates of future development costs per Mcfe for proved undeveloped reserves. These developments reflect a combination of factors including, among others:

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generally higher costs for leaseholds and oilfield services in a high commodity price environment;

elective development of locations on the periphery of the established productive area in the D-J Basin, with smaller reserve targets; and

limited proved reserves additions to date in the Powder River Basin CBM area, as work on federal acreage has been deferred pending resolution of matters relating to the EIS, and as CBM development has gradually moved from the primary areas of initial development in the play toward the west where Prima s undeveloped lease holdings are concentrated.

Prima s margins generally remained strong, on average, during the three years ended December 31, 2003, reflecting favorable oil and gas prices and combined related costs at or below $1.80 per Mcfe (see table below). We expect our future profitability to continue to be largely determined by commodity prices and our success in growing reserves and production at reasonable average costs per unit. There can be no assurance that future oil and gas prices will be favorable or that we will be successful in adding reserves at an acceptable cost and growing our production.

Except in 2002, when we sold our Stones Throw CBM property two months into the year while it was producing approximately 6,800 net Mcf per day, Prima s net production has grown each year since 1988, including a 46% improvement from 2002 to 2003. Proved reserves have not been increased during the past three years though, as reserves were produced, properties were sold, estimates of proved undeveloped CBM reserves were lowered pending accumulation of additional data as industry activity in the area was slowed by regulatory matters, and while Prima made limited investments in activities that would add new proved reserves in the short term. During this three-year period, our net investments in oil and gas properties represented approximately 76% of total cash provided by operations and focused primarily on development of proved undeveloped reserves and activities in the Powder River Basin CBM play and the Coyote Flats prospect in Utah where operations are still ongoing to evaluate the properties. We anticipate that these operations will continue to be among our most important near-term activities undertaken for purposes of establishing new proved reserves and expanding production, though favorable results cannot be assured.

The following table, which presents selected operating data, is followed by further discussion of our results of operations for the periods indicated:

	2003	2002	2001
Proved reserves at end of year (Mcfe)	125,796,000	111,104,000	135,586,000
Production:			
Natural gas (Mcf)	13,015,000	8,343,000	9,277,000
Oil (barrels)	401,000	373,000	431,000
Total natural gas equivalents (Mcfe)	15,421,000	10,580,000	11,863,000
Revenue:			
Natural gas sales	$ 45,911,000	$ 16,413,000	$ 33,392,000
Oil sales	$ 12,711,000	$ 9,372,000	$ 11,156,000
Total oil and gas sales	$ 58,622,000	$ 25,785,000	$ 44,548,000
Avg. sales price (including hedging effects):			
Natural gas (per Mcf)	$ 3.53	$ 1.97	$ 3.60
Oil (per barrel)	$ 31.71	$ 25.14	$ 25.88
Total natural gas equivalents (per Mcfe)	$ 3.80	$ 2.44	$ 3.76
Expenses (per Mcfe):			
Depletion of oil and gas properties	$ 0.97	$ 0.92	$ 0.77

Lease operating expense	$ 0.23	$ 0.29	$ 0.28
Ad valorem and production taxes	$ 0.38	$ 0.20	$ 0.28
General and administrative expense	$ 0.22	$ 0.31	$ 0.30
	$ 1.80	$ 1.72	$ 1.63

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2003 vs. 2002

For the year ended December 31, 2003, we reported net income of $23,795,000, or $1.82 per diluted share, on revenues of $70,154,000. These amounts compare to net income of $5,230,000, or $0.40 per diluted share, on revenues of $31,790,000, for the year ended December 31, 2002. Total expenses, other than income taxes, were $35,247,000 in 2003 compared to $25,735,000 in 2002. Revenues increased $38,364,000 or 121%, expenses increased $9,512,000 or 37%, and net income increased $18,565,000 or 355% in 2003.

During 2003, we recognized $2,734,000 of total gains relating to oil and gas derivatives, comprised of $414,000 of hedging gains that were included in our reported oil and gas sales and $2,320,000 of separately reported gains on derivative instruments that did not qualify for hedge accounting. The net gains recognized on derivative instruments not qualifying for hedge accounting (which consisted primarily of NYMEX gas swaps without corresponding swaps for Rocky Mountain basis differentials) included related mark-to-market adjustments to fair value during the year.

Our revenues for 2002 included $3,376,000 of aggregate losses from oil and gas derivatives, including hedging losses of $458,000 plus $2,918,000 of reported losses on derivative instruments not qualifying for hedge accounting. The $2,918,000 of losses on non-qualifying hedges included $4,464,000 of net unrealized losses that primarily represented reversals of unrealized mark-to-market gains recognized in the prior year. These reversals occurred because mark-to-market gains on natural gas futures positions held at December 31, 2001 were reduced as gas prices escalated in 2002 before the contracts were settled.

Oil and gas sales reported for 2003 totaled $58,622,000, compared to $25,785,000 for 2002, an increase of 127%. The large improvement in such sales was due to a 46% year-over-year increase in production volumes and a 56% increase in the average price realized per equivalent unit of oil and gas production.

The following information excludes hedging effects (whereas the table above includes hedging effects). Our oil and gas sales in 2003 were $58,208,000, compared to $26,243,000 in 2002, an increase of $31,965,000 or 122%.The average sales price received by us for natural gas production in 2003 was $3.51 per Mcf, compared to $1.98 per Mcf in 2002, an increase of $1.53 per Mcf, or 77%. The average price received per barrel of oil was $31.38 in 2003, compared to $26.08 in 2002, representing an increase of $5.30 per barrel or 20%. On an Mcf equivalent basis, the average price received was $3.77 per Mcfe in 2003 compared to $2.48 per Mcfe in the prior year, representing an overall 52% increase in average prices. The portion of our total oil and gas revenues that was derived from natural gas was 78% in 2003 compared to 63% in 2002.

Our natural gas production totaled 13,015,000 Mcf in 2003 compared to 8,343,000 Mcf in 2002, representing an increase of 4,672,000 Mcf, or 56%. Our oil production totaled 401,000 barrels and 373,000 barrels in 2003 and 2002, respectively, representing an increase of 28,000 barrels, or 8%. Total production was 84% natural gas and 16% oil in 2003, compared to 79% gas and 21% oil in the prior year. This increase was due to Powder River Basin CBM operations, which generated net gas production of 6,474,000 Mcf in 2003, compared to 1,576,000 Mcf in 2002. Prima s CBM production to date has largely been attributable to the Stones Throw property, which was sold March 5, 2002, and the Porcupine-Tuit property, which began producing from 27 wells during the third quarter of 2002. Production from Porcupine-Tuit increased during the second half of 2002 and in 2003 as de-watering occurred, new wells were drilled and brought on-line, and additional compression capacity was installed by the gathering company. At the end of 2003, Prima had 85 wells on-line at Porcupine-Tuit producing at a combined net daily rate of approximately 19,500 Mcf.

Our depletion expense for oil and gas properties in 2003 was $14,956,000 or $0.97 per Mcfe, compared to $9,710,000, or $0.92 per Mcfe, in 2002, an increase of $5,246,000 or 54%. The increase in the per-unit depletion rate primarily reflects higher average costs per Mcfe for 2003 reserve additions than our historical average and increased estimates for future development costs. Depreciation of other fixed assets, which include service equipment, office furniture and equipment, and buildings, was $1,058,000 and $1,088,000 for 2003 and 2002, respectively.

Lease operating expenses (LOE) totaled $3,619,000 for the year ended December 31, 2003 compared to $3,076,000 for the year ended December 31, 2002, an increase of $543,000 or 18%. The increase was primarily associated with the additional CBM production in 2003. On a per-unit-of-production basis, LOE decreased from $0.29 in 2002 to $0.23 in 2003. Ad valorem and production taxes were $2,116,000 and $5,783,000 in 2002 and 2003, respectively, an increase of $3,667,000 or 173%. Production taxes fluctuate with revenues and changing mill levy rates, and averaged 9.9% of total oil and gas sales excluding hedging effects in 2003 compared to 8.1% in 2002, reflecting a greater portion of oil and gas sales attributable to properties in Wyoming, which has higher production tax rates than Colorado. Total lifting costs (LOE plus ad valorem and production taxes) were $0.61 per Mcfe for 2003 compared to $0.49 per Mcfe for 2002.

Oilfield services revenues include well servicing fees from completion and swab rigs, CBM drilling rigs, trucking, water hauling, equipment rentals, and other related activities. Services are provided to both Prima and unaffiliated third parties, but intercompany billings are eliminated in consolidation. Revenues from third parties totaled $8,577,000 for the year ended December 31, 2003 compared to $8,326,000 for the year ended December 31, 2002, an increase of $251,000, or 3%. Costs of oilfield services provided to third parties were $6,510,000 in 2003 compared to $6,490,000 for 2002, an increase of $20,000 or less than 1%. Approximately 24% of fees billed by the service companies in 2003 were for Prima managed properties, compared to 19% in 2002. A 10% year-over-year increase in billings before intercompany eliminations, which was attributable to stronger demand for services, was partially offset by the increased portion of work performed on Prima-operated properties.

General and administrative expenses (G&A), net of third party reimbursements and amounts capitalized, were $3,321,000 for the year ended December 31, 2003 compared to $3,255,000 for the year ended December 31, 2002. Net G&A costs increased by 2% or $66,000. Higher total costs were partially offset by increased reimbursements of management and operator fees from third parties. These fees increased from $405,000 in 2002 to $601,000 in 2003, due to having more third party ownership in CBM wells drilled in 2003 than in prior years. Capitalized G&A was $2,124,000 in both 2003 and 2002.

Our provision for income taxes was $11,515,000 for the year ended December 31, 2003 compared to $825,000 for the year ended December 31, 2002. Our effective tax rate increased to 33% in 2003 from 13.7% in 2002. The higher effective tax rate in 2003 was primarily attributable to a $28,852,000, or 476%, increase in pre-tax income without a proportionate change in permanent differences. The effective tax rates in both years were less than statutory rates due to permanent differences in book and tax basis income, consisting primarily of statutory depletion deductions and, in 2002, Section 29 tax credits. The statutory provision under which Section 29 tax credits were generated by production from certain wells expired at the end of 2002.

Proved oil and gas reserves: From the end of 2002 to the end of 2003, our proved oil and gas reserves increased by 14,692 MMcfe, from 111,104 MMcfe to 125,796 MMcfe. The 13% year-over-year increase in proved reserves was due to additions of 15,482 MMcfe from extensions, discoveries and acquisitions, and 19,382 MMcfe of net positive revisions, partially offset by 15,421 MMcfe of net production and 4,751 MMcfe of net proved reserves sold or swapped for other assets. The extensions, discoveries and acquisitions were primarily attributable to activities in the D-J Basin and revisions were largely due to the effect of higher gas prices. Other activities during 2003, including operations in the Powder River Basin CBM play and Prima s Coyote Flats prospect in Utah, were primarily associated with development of proved undeveloped reserves or related to properties still being evaluated for proved oil and gas reserves.

2002 vs. 2001

For the year ended December 31, 2002, we reported net income of $5,230,000, or $0.40 per diluted share, on revenues of $31,790,000. These amounts compared to net income of $23,768,000, or $1.80 per diluted share, on revenues of

$60,287,000, for the year ended December 31, 2001. Total expenses, other than income taxes, were $25,735,000 in 2002 compared to $26,480,000 in 2001. Revenues decreased $28,497,000 or 47%, expenses decreased $745,000 or 3%, and net income decreased $18,538,000 or 78% in 2002.

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Our revenues for 2002 included $3,376,000 of aggregate losses from oil and gas derivatives, comprised of hedging losses of $458,000 included in our oil and gas sales, plus $2,918,000 of separately reported losses on derivative instruments that did not qualify for hedge accounting. The derivative instruments that didn t qualify for hedge accounting were principally NYMEX gas swaps for which we did not elect to enter into corresponding swaps for Rocky Mountain basis differentials. The related $2,918,000 of losses consisted of $1,546,000 of net amounts received on positions closed in 2002, offset by $4,464,000 of net unrealized losses recorded primarily to reverse unrealized mark-to-market gains recognized in the prior year, as mark-to-market gains on positions held at December 31, 2001 declined when gas prices escalated in 2002 before the contracts were settled. During 2001, we recognized $9,816,000 of gains from oil and gas derivatives, consisting of hedging gains of $3,381,000, realized ineffective hedging gains of $2,057,000, and unrealized mark-to-market gains of $4,378,000.

Oil and gas sales reported for 2002 totaled $25,785,000, compared to $44,548,000 for 2001, a decrease of 42%. The lower revenues were due to an 11% year-over-year decrease in production volumes and a 35% decrease in the average price realized per equivalent unit of natural gas and oil production. Excluding hedging effects, our oil and gas sales reported for 2002 were $26,243,000, compared to $41,167,000 for 2001, a decrease of $14,924,000 or 36%.

Prima s natural gas production totaled 8,343,000 Mcf in 2002 compared to 9,277,000 Mcf in 2001, representing a decrease of 934,000 Mcf, or 10%. Our oil production totaled 373,000 barrels and 431,000 barrels in 2002 and 2001, respectively, representing a decrease of 58,000 barrels, or 13%. On an equivalent unit basis, production declined from 11,863,000 Mcfe in 2001 to 10,580,000 Mcfe in 2002. Total production was 79% natural gas and 21% oil in 2002, compared to 78% gas and 22% oil in the prior year. Our Stones Throw CBM property, which was sold in March 2002, contributed 298,000 net Mcf during the two months the property was owned in 2002, compared to 1,321,000 Mcf in 2001, largely accounting for the declines in gas volumes and net equivalent units. Gas production from the Porcupine-Tuit CBM property, which was initiated at the end of July 2002, roughly offset oil and gas production declines on other properties. Such declines were attributable to a high level of drilling and well recompletion activity in the first half of 2001, in response to a strong commodity price environment, followed by reduced activity levels in the second half of 2001 and in 2002 in response to a significant decline in Rocky Mountain gas prices.

The following information excludes hedging effects (whereas the table above includes hedging effects). The average sales price received by us for natural gas production in 2002 was $1.98 per Mcf, compared to $3.24 per Mcf in 2001, a decrease of $1.26 per Mcf, or 39%. The average price received per barrel of oil was $26.08 in 2002, compared to $25.68 in 2001, representing an increase of $0.40 per barrel or 2%. On an Mcf equivalent basis, the average price received was $2.48 per Mcfe in 2002 compared to $3.47 per Mcfe in the prior year, representing an overall 29% decline in average prices. The portion of our total oil and gas revenues that was derived from natural gas was 63% in 2002 compared to 73% in 2001.

Our depletion expense for oil and gas properties in 2002 was $9,710,000, or $0.92 per Mcfe, compared to $9,190,000, or $0.77 per Mcfe, in 2001, an increase of $520,000 or 6%. The increase in the per-unit depletion rate primarily reflects a decline in estimated proved reserve quantities related to Powder River Basin CBM properties. These adjustments are discussed below. Depreciation of other fixed assets, which include service equipment, office furniture and equipment, and buildings, was $1,088,000 and $1,039,000 for 2002 and 2001, respectively.

Lease operating expenses totaled $3,076,000 for the year ended December 31, 2002 compared to $3,295,000 for the year ended December 31, 2001, a decrease of $219,000 or 7%. The decrease was primarily attributable to the sale of the Stone s Throw CBM wells in March 2002. On a per-unit-of-production basis, LOE increased slightly, from $0.28 in 2001 to $0.29 in 2002. Ad valorem and production taxes were $2,116,000 and $3,344,000 for the same periods, a decrease of $1,228,000 or 37%. Production taxes fluctuate with revenues and changing mill levy rates, and averaged 8.1% of total oil and gas sales excluding hedging effects in both 2002 and 2001. Total lifting costs (LOE plus ad valorem and production taxes) were $0.49 per Mcfe for 2002 compared to $0.56 per Mcfe for 2001.

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Oilfield services revenues from third parties totaled $8,326,000 in 2002 compared to $8,090,000 in 2001, an increase of $236,000, or 3%. Costs of oilfield services provided to third parties were $6,490,000 in 2002 compared to $5,812,000 for 2001, an increase of $678,000 or 12%. Approximately 19% of fees billed by the service companies in 2002 were for Prima managed properties, compared to 34% in 2001. Lower total billings in 2002, caused by the effects on demand of relatively low Rocky Mountain gas prices and pending regulatory decisions relating to Powder River Basin CBM development, were offset by the reduced portion of services performed on behalf of Prima. The disproportionate increase in costs associated with services provided third parties primarily reflects a change in the mix of activities conducted for both Prima and other operators, including a greater weighting of high margin services provided to Prima in 2002 which were eliminated in consolidation.

General and administrative expenses, net of third party reimbursements and amounts capitalized, were $3,255,000 for the year ended December 31, 2002 compared to $3,559,000 for the year ended December 31, 2001. Net G&A costs decreased by $304,000 or 9% due to increased third party reimbursements and greater amounts capitalized. Third party reimbursements of management and operator fees increased from $371,000 in 2001 to $405,000 in 2002, due to having increased third party ownership in properties drilled or refractured in the current year. Capitalized G&A increased from $1,753,000 in 2001 to $2,124,000 in 2002, reflecting increased costs associated with exploration, exploitation and development activities.

Our provision for income taxes was $825,000 for the year ended December 31, 2002 compared to $10,650,000 for the year ended December 31, 2001, a decrease of $9,825,000 or 92%. Our effective tax rate decreased to 13.7% in 2002 from 31.5% in 2001. The effective tax rates in both years were less than statutory rates due to permanent differences in book and tax basis income, consisting primarily of statutory depletion deductions and Section 29 tax credits. The lower effective tax rate in 2002 was primarily attributable to a $27,752,000, or 82%, decrease in pre-tax income without a proportionate change in permanent differences.

Proved oil and gas reserves: From the end of 2001 to the end of 2002, our proved oil and gas reserves declined by 24,482 MMcfe, from 135,586 MMcfe to 111,104 MMcfe. The year-over-year decline primarily reflected 8,259 MMcfe of property sales and exchanges, most of which was accounted for by the Stones Throw property disposition, and net revisions aggregating 16,614 MMcfe. Estimated additions to proved reserves from extensions, discoveries and acquisitions in 2002 totaled 10,971 MMcfe, slightly greater than total production during the year of 10,580 MMcfe. Most of Prima s investments in 2002 were directed toward activities that did not add, nor were expected to add, significant incremental proved reserves during the year, including:

- development of previously-established proved reserves in the D-J Basin and at the Porcupine-Tuit CBM property;
- pilot projects in the Powder River Basin designed to evaluate and develop deeper coal seams, which will generate proved reserves additions in future periods if our expectations are met;
- exploration on the Coyote Flats prospect in Utah, where the initial test well had not yet been completed and determination of commerciality was still pending; and
- exploratory acreage acquisitions.

Net revisions to proved reserves during the year were primarily attributable to Prima s Powder River Basin CBM properties and reflected incorporation of additional data from activities conducted by Prima and other operators, as well as certain regulatory developments. The revisions reflected the following adjustments to previous estimates:

- we increased estimated future development and operating costs, to reflect rising costs for certain services and arrangements with surface owners;

we increased projected costs for water disposal due to anticipated regulatory actions;

we incorporated expectations of longer lead times for property development, due primarily to anticipated regulatory constraints;

we modified the projected production profile, to provide for longer de-watering times; and,

we excluded all undrilled locations for which economic runs indicated expected returns above 10%, but less than 20%, to more closely approximate our internal hurdle rate.

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As a result, our estimated reserves at the end of 2002 generally excluded properties with thinner, shallower coals that we did not anticipate developing at that time, as we focused planned activities on reserve targets assessed as being larger with higher potential economic returns. At December 31, 2002, these higher-potential reserve targets were not proved. Generally, such targets are deeper and thicker coals than the Wyodak coals that were extensively developed in the initial phases of the industry s exploitation of CBM potential in the Powder River Basin. At the end of 2002, these deeper coals were in the early stages of evaluation and development by Prima and other operators in the area.

New Accounting Pronouncements

In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity to improve the accounting for certain financial instruments that, under previous guidance, issuers could account for as equity. SFAS No. 150 requires that those instruments be classified as liabilities in statements of financial position. SFAS No. 150 does not apply to features embedded in a financial instrument that is not a derivative in its entirety. In addition to its requirements for the classification and measurement of financial instruments within its scope, SFAS No. 150 also requires disclosures about alternative ways of settling the instruments and the capital structure of entities, all of whose shares are mandatorily redeemable. Most of the guidance in Statement 150 is effective for all financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. As we have no such financial instruments, we do not anticipate any impact on our financial position or results of operations upon adoption.

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141, Business Combinations, and SFAS No. 142, Goodwill and Other Intangible Assets, to companies in the extractive industries, including oil and gas companies. The issue is whether the Financial Accounting Standards Board (FASB) intended to require companies to classify the costs of mineral rights held under lease or other contractual arrangements associated with extracting oil and gas as intangible assets in balance sheets, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, we have included the costs of such mineral rights associated with extracting oil and gas as a component of our investments in oil and gas properties. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify the costs associated with mineral rights as a separate category of intangible assets on balance sheets, we would be required to reclassify approximately $27 million at December 31, 2003 and $26 million at December 31, 2002 out of oil and gas properties and into a separate intangible assets line item. Our results of operations and cash flows would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full-cost accounting rules.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our primary market risks relate to changes in prices received on sales of natural gas and oil production. We periodically enter into derivative contracts to mitigate a portion of this commodity price risk, or in an effort to enhance profitability. Such derivatives consist of commodity futures or price swaps (agreements with counterparties to exchange floating prices for fixed prices), and options on such futures or price swaps. Generally, these instruments reduce our exposure to decreases in gas and oil prices, or increases in differentials between NYMEX and Rocky Mountain gas prices, but they also typically limit the benefits we realize from increases in prices or narrowing of basis differentials. When hedging only a portion of our exposure to changes in prices, we are able to partially benefit from increases in gas and oil prices or improvements in basis differentials, but we remain exposed to market risk on the portion of our production not covered by such derivatives. We also retain risks related to the ineffective portion of such derivatives instruments, when applicable.

We may enter into derivatives positions intended to offset risks associated with downward price movements in benchmark NYMEX oil and gas prices, as well as basis swaps to protect us from increases in the differential between NYMEX and Rocky Mountain gas prices. Our derivatives contracts generally represent cash flow hedges that are determined to be qualifying or non-qualifying for hedge accounting treatment in accordance with the provisions of SFAS 133. At times, however, we may consider establishing derivative positions that do not represent cash flow hedges. See

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Note 1 and Note 5 of Notes to Consolidated Financial Statements for additional information with respect to derivatives and related accounting policies.

Personnel who we believe have appropriate skills and experience execute all derivatives transactions. The personnel involved in these activities must follow prescribed trading limits and parameters that are regularly reviewed by our Chief Executive Officer. Our Chief Executive Officer approves all derivatives transactions before being entered into and our Board of Directors regularly reviews outstanding positions and hedging strategy. We use only conventional derivatives instruments and attempt to manage our credit risk by entering into derivatives contracts only with financial institutions that we believe to be reputable and which carry an investment grade rating.

Following are disclosures regarding our market risk instruments. Investors and other users are cautioned to avoid simplistic use of these disclosures. Users should realize that the actual impact of future commodity price movements will likely differ from the amounts disclosed below due to ongoing changes in risk exposure levels and concurrent adjustments to positions. It is not possible to accurately predict future movements in natural gas and oil prices.

During 2003, we sold 401,000 barrels of produced oil. A hypothetical decrease of $3.14 per barrel (10% of average prices for the period exclusive of hedging transactions) would have decreased our revenues by $1,259,000 for the period. We sold 13,015,000 Mcf of produced natural gas during the same period. A hypothetical decrease of $0.35 per Mcf (10% of average prices for the period exclusive of hedging transactions) would have decreased our revenues by $4,555,000 for the period.

We have realized net losses totaling $442,000 on positions closed out in 2004 relating to contract months of January through March 2004. At the close of business on February 27, 2004, the fair value of our remaining oil and gas derivatives instruments reflected a net loss of $2,474,000, as shown below:

Time Period	**Market Index**	**Total Volumes (MMBtu or Bbls)**	**Average Contract Price**	**Fair Value**
Natural Gas Futures				
April October 2004	NW Rockies	4,900,000	$ 4.41	$(1,818,000)
November 2004	CIG	350,000	4.00	(343,000)
Crude Oil Futures				
April September 2004	NYMEX	95,000	31.27	(313,000)
Total Net Fair Value				$(2,474,000)

All of the derivative positions scheduled above are considered to be effective hedges. Combined, these positions total approximately 5,820,000 Mcfe of volumes.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our Consolidated Financial Statements are attached at the end of this Annual Report on Form 10-K. An index to these Consolidated Financial Statements is also included in Item 15(a) of this Annual Report on Form 10-K.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Since our inception, there has not been any Form 8-K filed under the Securities Exchange Act of 1934 reporting a change in accountants in which there was a reported disagreement on any matter of accounting principles or practices or financial statement disclosure.

ITEM 9A. CONTROLS AND PROCEDURES

Prima s principal executive officer and principal financial officer have evaluated the effectiveness of our disclosure controls and procedures, as such term is defined in Rule 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, within 90 days of the filing date of this Annual Report on Form 10-K. Based upon their evaluation, our principal executive officer and principal financial officer concluded that Prima s disclosure controls and procedures are effective as of the end of the period covered by this report. There were no significant changes in our internal controls or in other factors that could significantly affect these controls, since the date the controls were evaluated.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

ITEM 11. EXECUTIVE COMPENSATION

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Pursuant to instruction G(3) to Form 10-K, Items 10, 11, 12, 13 and 14 are omitted because we intend to file a definitive proxy statement pursuant to Regulation 14A under the Securities Exchange Act of 1934 not later than 120 days after the close of the fiscal year. The information required by such Items will be included in the definitive proxy statement to be filed for our annual meeting of stockholders and is hereby incorporated by reference.

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a)(1) Financial Statements

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(a)(2) Financial Statement Schedules

Financial statement schedules have been omitted because they are not applicable or the information required therein is included elsewhere in the financial statements or notes thereto.

(b) Reports on Form 8-K

During the quarter ended December 31, 2003, Prima filed the following current report on Form 8-K:

Report dated November 6, 2003, reporting earnings for the quarter and nine months ended September 30, 2003, and providing an update of commodity hedging transactions, operating activities and 2003 production forecasts.

(c) Exhibits

The following exhibits are filed with or are incorporated by reference into this report on Form 10-K.

Exhibit No.	Document
3.1	Certificate of Incorporation of Prima Energy Corporation, Delaware, as filed August 18, 1988. (Incorporated by reference to Registration of Securities of Certain Successor Issuers on Form 8-B dated January 20, 1989.)
3.2	Certificate of Amendment of Certificate of Incorporation of Prima Energy Corporation filed May 1, 1989. (Incorporated by reference to Annual Report on Form 10-K for Prima Energy Corporation for the

	year ended June 30, 1989.)
3.3	Bylaws of Prima Energy Corporation. (Incorporated by reference to Registration of Securities of Certain Successor Issuers on Form 8-B dated January 20, 1989.)
3.4	Certificate of Amendment of the Certificate of Incorporation of Prima Energy Corporation. (Incorporated by reference to Quarterly Report on Form 10-Q for Prima Energy Corporation for the quarter ended June 30, 1997.)

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Exhibit No.	Document
3.5	Certificate of Amendment of the Certificate of Incorporation of Prima Energy Corporation. (Incorporated by reference to Quarterly Report on Form 10-Q for Prima Energy Corporation for the quarter ended September 30, 2000.)
3.6	Certificate of Amendment of the Certificate of Incorporation of Prima Energy Corporation. (Incorporated by reference to Quarterly Report on Form 10-Q for Prima Energy Corporation for the quarter ended June 30, 2001.)
4.1	Rights Agreement dated as of May 23, 2001, between Prima Energy Corporation and Computershare Trust Company, Inc., as Rights Agent, including the form of Certificate of Designation, Powers, Preferences and Rights of Series A Participating Preferred Stock dated May 29, 2001, the Form of Right Certificate, and the Summary of Rights to Purchase Preferred Shares. (Incorporated by reference to Current Report on Form 8-K for Prima Energy Corporation dated May 23, 2001.)
10.1	Prima Energy Corporation Employee Stock Ownership Plan (Incorporated by reference to Annual Report on Form 10-K for Prima Energy Corporation for the year ended June 30, 1989.)
10.2	Prima Energy Corporation 1993 Stock Incentive Plan. (Incorporated by reference to Annual Report on Form 10-K for Prima Energy Corporation for the year ended December 31, 1993.)
10.3	Agreement of Lease between Denver-Stellar Associates LP, Landlord and Prima Energy Corporation, Tenant, effective December 1, 2001. (Incorporated by reference to Annual Report on Form 10-K for Prima Energy Corporation for the year ended December 31, 2000.)
10.4	Prima Energy Corporation Non-Employee Directors Stock Option Plan. (Incorporated by reference to Quarterly Report on Form 10-Q for Prima Energy Corporation for quarter ended March 31, 2002.)
10.5	Prima Energy Corporation 2001 Stock Incentive Plan. (Incorporated by reference to Quarterly Report on Form 10-Q for Prima Energy Corporation for the quarter ended March 31, 2002.)
14.1	Prima Energy Corporation Code of Ethics for Senior Financial Officers
21.1	Subsidiaries of the Registrant
23.1	Independent Auditors Consent
23.2	Independent Reservoir Engineers and Geologists Consent

31.1	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended
31.2	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a) /15d-14(a) of the Securities Exchange Act of 1934, as amended
32.1	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 USC Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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INDEPENDENT AUDITORS REPORT

Prima Energy Corporation:

We have audited the accompanying consolidated balance sheets of Prima Energy Corporation (the Company) and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of income, cash flows, stockholders equity, and comprehensive income for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company and its subsidiaries at December 31, 2003 and 2002, and the results of their operations and their 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.

As discussed in Note 1 to the consolidated financial statements, in 2001 the Company adopted Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities and in 2003 the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations.

DELOITTE & TOUCHE LLP

March 11, 2004
Denver, Colorado

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PRIMA ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2003 and 2002

ASSETS

	2003	2002
CURRENT ASSETS		
Cash and cash equivalents	$ 55,918,000	$ 36,263,000
Available for sale securities, at market	1,274,000	1,744,000
Receivables (net of allowance for doubtful accounts: $281,000 and $304,000)	10,759,000	7,492,000
Inventory	1,012,000	940,000
Other	938,000	818,000
Total current assets	69,901,000	47,257,000
OIL AND GAS PROPERTIES, at cost, accounted for using the full cost method:		
Proved	150,575,000	130,948,000
Unproved	27,317,000	20,570,000
Less accumulated depreciation, depletion and amortization	(76,478,000)	(62,980,000)
Oil and gas properties net	101,414,000	88,538,000
OTHER PROPERTY AND EQUIPMENT, at cost		
Oilfield service equipment	9,737,000	9,457,000
Furniture and equipment	713,000	712,000
Field office, shop and land	451,000	478,000
	10,901,000	10,647,000
Less accumulated depreciation	(6,183,000)	(5,808,000)
Other property and equipment net	4,718,000	4,839,000
OTHER ASSETS	1,184,000	1,293,000

	$177,217,000	$141,927,000

See accompanying notes to consolidated financial statements.

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PRIMA ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS (cont d.)
DECEMBER 31, 2003 and 2002

LIABILITIES AND STOCKHOLDERS EQUITY

	2003	2002
CURRENT LIABILITIES		
Accounts payable	$ 3,722,000	$ 3,129,000
Amounts payable to oil and gas property owners	2,620,000	3,192,000
Ad valorem and production taxes payable	3,477,000	3,864,000
Accrued and other liabilities	1,951,000	893,000
Derivatives, at fair value	1,983,000	225,000
Total current liabilities	13,753,000	11,303,000
AD VALOREM TAXES, non-current	3,634,000	2,077,000
ASSET RETIREMENT OBLIGATIONS	1,903,000	
DEFERRED INCOME TAX LIABILITY	27,251,000	21,281,000
Total liabilities	46,541,000	34,661,000
STOCKHOLDERS EQUITY		
Preferred stock, $0.001 par value, 2,000,000 shares authorized; no shares issued		
Common stock, $0.015 par value, 35,000,000 shares authorized; 13,312,548 and 13,064,048 shares issued	200,000	196,000
Additional paid-in capital	8,455,000	5,250,000
Retained earnings	131,265,000	107,470,000
Accumulated other comprehensive loss	(1,598,000)	(115,000)
Treasury stock, 348,406 and 236,538 shares, at cost	(7,646,000)	(5,535,000)
Stockholders equity net	130,676,000	107,266,000
	$177,217,000	$141,927,000

See accompanying notes to consolidated financial statements.

PRIMA ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 and 2001

	2003	2002	2001
REVENUES			
Oil and gas sales	$58,622,000	$25,785,000	$44,548,000
Gains (losses) on derivative instruments, net	2,320,000	(2,918,000)	6,435,000
Oilfield services	8,577,000	8,326,000	8,090,000
Interest, dividend and other income	635,000	597,000	1,214,000
	70,154,000	31,790,000	60,287,000
EXPENSES			
Depreciation, depletion and amortization:			
Depletion of oil and gas properties	14,956,000	9,710,000	9,190,000
Depreciation of property and equipment	1,058,000	1,088,000	1,039,000
Lease operating expense	3,619,000	3,076,000	3,295,000
Ad valorem and production taxes	5,783,000	2,116,000	3,344,000
Oilfield services	6,510,000	6,490,000	5,812,000
General and administrative	3,321,000	3,255,000	3,559,000
Impairment of natural gas swap			241,000
	35,247,000	25,735,000	26,480,000
Income before income taxes and cumulative effect of change in accounting principle	34,907,000	6,055,000	33,807,000
Provision for income taxes	11,515,000	825,000	10,650,000
Net income before cumulative effect of change in accounting principle	23,392,000	5,230,000	23,157,000
Cumulative effect of change in accounting principle (net of income taxes of $217,000 and $265,000)	403,000		611,000
NET INCOME	$23,795,000	$ 5,230,000	$23,768,000

Basic net income per share before cumulative effect of change in accounting principle	$	1.82	$	0.41	$	1.82
Cumulative effect of change in accounting principle		0.03				0.05
BASIC NET INCOME PER SHARE	$	1.85	$	0.41	$	1.87
Diluted net income per share before cumulative effect of change in accounting principle	$	1.79	$	0.40	$	1.75
Cumulative effect of change in accounting principle		0.03				0.05
DILUTED NET INCOME PER SHARE	$	1.82	$	0.40	$	1.80

See accompanying notes to consolidated financial statements.

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PRIMA ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 and 2001

	2003	2002	2001
OPERATING ACTIVITIES			
Net income	$ 23,795,000	$ 5,230,000	$ 23,768,000
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	16,014,000	10,798,000	10,229,000
Deferred income taxes	6,416,000	(977,000)	9,123,000
Cumulative effect of change in accounting principle	(403,000)		
Unrealized derivative activities	(685,000)	4,464,000	(4,378,000)
Tax benefits from stock option plans	1,913,000	1,250,000	732,000
Other	108,000	298,000	224,000
Changes in operating assets and liabilities:			
Receivables	(3,275,000)	(1,698,000)	3,096,000
Inventory	(72,000)	475,000	(6,000)
Other current assets	89,000	89,000	241,000
Accounts payable and payables to owners	21,000	2,743,000	(2,130,000)
Production taxes payable	1,170,000	(633,000)	1,504,000
Accrued and other liabilities	1,058,000	(515,000)	605,000
Net cash provided by operating activities	46,149,000	21,524,000	43,008,000
INVESTING ACTIVITIES			
Additions to oil and gas properties	(26,856,000)	(22,252,000)	(35,248,000)
Purchases of other properties	(1,422,000)	(1,142,000)	(1,958,000)
Purchases of available-for-sale securities	(552,000)	(272,000)	(125,000)
Proceeds from sales of oil and gas property	1,765,000	14,577,000	57,000
Proceeds from sales of securities	1,177,000	929,000	166,000
Proceeds from sales of other property and equipment	209,000	375,000	212,000
Net cash used in investing activities	(25,679,000)	(7,785,000)	(36,896,000)
FINANCING ACTIVITIES			
Treasury stock purchased	(2,111,000)	(1,669,000)	(3,866,000)
Proceeds from exercise of stock options	1,296,000	856,000	526,000
Other			183,000

Net cash used in financing activities	(815,000)	(813,000)	(3,157,000)
Increase in cash and cash equivalents	19,655,000	12,926,000	2,955,000
Cash and cash equivalents, beginning of year	36,263,000	23,337,000	20,382,000
CASH AND CASH EQUIVALENTS, end of year	$ 55,918,000	$ 36,263,000	$ 23,337,000

See accompanying notes to consolidated financial statements.

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PRIMA ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 and 2001

	Common Stock		Additional Paid-In	Retained	Accumulated Other Comprehensive Income	Treasury Stock		
	Shares	Amount	Capital	Earnings	(Loss)	Shares	Amount	Total
BALANCES, January 1, 2001	12,793,373	$192,000	$1,760,000	$ 78,472,000	$ (126,000)		$	$ 80,298,000
Net income				23,768,000				23,768,000
Exercise of stock options	96,550	1,000	525,000					526,000
Tax benefit from exercise of non-qualified stock options			732,000					732,000
Other comprehensive income					152,000			152,000
Treasury stock purchased						155,351	(3,866,000)	(3,866,000)
Other			130,000					130,000
BALANCES, December 31, 2001	12,889,923	193,000	3,147,000	102,240,000	26,000	155,351	(3,866,000)	101,740,000
Net income				5,230,000				5,230,000
Exercise of stock options	174,125	3,000	853,000					856,000
Tax benefit from exercise of non-qualified stock options			1,250,000					1,250,000
Other comprehensive loss					(141,000)			(141,000)
Treasury stock purchased						81,187	(1,669,000)	(1,669,000)
	13,064,048	196,000	5,250,000	107,470,000	(115,000)	236,538	(5,535,000)	107,266,000

BALANCES, December 31, 2002								
Net income				23,795,000				23,795,000
Exercise of stock options	248,500	4,000	1,292,000					1,296,000
Tax benefit from exercise of non-qualified stock options			1,913,000					1,913,000
Other comprehensive loss					(1,483,000)			(1,483,000)
Treasury stock purchased						111,868	(2,111,000)	(2,111,000)
BALANCES, December 31, 2003	13,312,548	$200,000	$8,455,000	$131,265,000	$(1,598,000)	348,406	$(7,646,000)	$130,676,000

See accompanying notes to consolidated financial statements.

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PRIMA ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 and 2001

	2003	2002	2001
Net income	$23,795,000	$5,230,000	$23,768,000
Other comprehensive income (loss):			
Change in fair value of hedges	(2,029,000)	(690,000)	3,475,000
Reclassification adjustment for realized (gains) losses on hedges included in net income	(414,000)	458,000	(3,381,000)
Deferred income tax benefit (expense) related to change in fair value of hedges	904,000	86,000	(35,000)
Change in fair value of available-for-sale securities	155,000	(16,000)	147,000
Reclassification adjustment for realized (gains) losses included in net income	(66,000)	25,000	1,000
Deferred income tax expense related to change in fair value of available-for-sale securities	(33,000)	(4,000)	(55,000)
	(1,483,000)	(141,000)	152,000
COMPREHENSIVE INCOME	$22,312,000	$5,089,000	$23,920,000

See accompanying notes to consolidated financial statements.

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PRIMA ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 and 2001

1. ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

Business and Basis of Presentation

The accompanying consolidated financial statements include the accounts of Prima Energy Corporation and its wholly owned subsidiaries, herein collectively referred to as Prima or the Company. Prima s primary business is the exploration for, and the acquisition, development and production of, crude oil and natural gas. The Company is also engaged in oil and gas property operations and oilfield services, and, at times, has engaged in natural gas gathering, marketing and trading. Prima s activities have been conducted predominantly in the Rocky Mountain region of the United States.

The Company s proportionate share of capital expenditures, production revenue and operating expenses from working interests in oil and gas properties is included in the consolidated financial statements. All significant intercompany transactions have been eliminated. Certain amounts in prior years have been reclassified to conform to the classifications at December 31, 2003.

Use of Estimates

The preparation of the Company s financial statements in conformity with generally accepted accounting principles 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 these estimates.

Comprehensive Income

Comprehensive income consists of net income, unrealized gains and losses on marketable equity securities held for sale, and the effective component of derivative instruments classified as cash flow hedges, net of income tax effects. Comprehensive income is presented in the Consolidated Statements of Comprehensive Income.

The balances of after-tax components comprising accumulated other comprehensive income (loss) as of December 31 are presented in the following table:

	2003	2002	2001
Unrealized gain (loss) on effective component of derivative instruments	$(1,626,000)	$ (87,000)	$ 59,000
Unrealized gain (loss) on marketable equity securities	28,000	(28,000)	(33,000)
Accumulated other comprehensive income (loss)	$(1,598,000)	$(115,000)	$ 26,000

Consolidated Statements of Cash Flows

Cash in excess of daily requirements has generally been invested in money market accounts and other cash equivalents with maturities of three months or less. Such investments are deemed to be cash equivalents for purposes of the consolidated financial statements.

Cash paid for income taxes was $2,153,000, $1,187,000 and $905,000 for the years ended December 31, 2003, 2002 and 2001, respectively. No interest was paid in 2003, 2002 or 2001.

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Estimated Fair Value of Financial Instruments and Available for Sale Securities

The carrying amount of cash equivalents approximates fair value because of the short maturity and high credit quality of those investments.

Marketable securities are classified as available for sale, and are carried on the balance sheet at market value. Unrealized gains and losses, net of deferred income taxes, are generally reported as other comprehensive income and as an adjustment to stockholders equity. If a decline in market value below cost is assessed as being other than temporary, such impairment is included in the determination of net income. Available-for-sale securities are readily marketable and available for use in Prima s operations should the need arise. Therefore, the Company has classified such securities as current assets. Realized gains and losses are determined on the specific identification method.

Commencing with its adoption of Statement of Financial Accounting Standards (SFAS) No. 133 on January 1, 2001, Prima has recognized all derivatives on its balance sheet at their estimated fair values. The fair values of these contracts are determined based on various factors, including contract volumes and prices, contract settlement dates, quoted closing prices on the NYMEX or over-the-counter and, where applicable, volatility and the time value of options. The calculation of the fair value of collars and floors requires the use of the Black-Scholes option-pricing model, but market quotations are generally available. Substantially all of the Company s derivatives positions are valued based upon reported settlement prices on the NYMEX or as quoted in relatively liquid over-the-counter markets by a number of market makers.

Inventory

Inventory consists of various tubular goods and surface production facility equipment intended to be used in Prima s oil and gas operations, and is stated at the lower of cost or market value using the first-in, first-out valuation method.

Oil and Gas Properties

Prima utilizes the full cost method of accounting for oil and gas producing activities. Under this method, all costs associated with property acquisition, exploration and development, including costs of unsuccessful exploration and asset retirement obligations, are capitalized within a cost center. Prima s oil and gas properties are all located within the United States, which constitutes a single cost center. No gain or loss is recognized upon the sale or abandonment of undeveloped or producing oil and gas properties unless the sale represents a significant portion of oil and gas properties and the gain significantly alters the relationship between capitalized costs and proved oil and gas reserves of the cost center. Depreciation, depletion and amortization of oil and gas properties is computed on the units-of-production method based on proved reserves. Amortizable costs include estimates of future development costs of proved reserves. Prima invests in unevaluated oil and gas properties for the purpose of exploration for proved reserves. The costs of such assets, including exploration costs on properties where a determination of whether proved oil and gas reserves will be established is still pending, are included in unproved oil and gas properties at the lower of cost or estimated fair market value and are not subject to amortization.

Capitalized costs of oil and gas properties may not exceed an amount equal to the present value, discounted at 10%, of the estimated future net cash flows from proved oil and gas reserves plus the cost, or estimated fair market value if lower, of unproved properties. Should capitalized costs exceed this ceiling, an impairment is recognized. The present value of estimated future net cash flows is computed based on revenues derived using oil and natural gas prices and projected future production of proved reserves as of the balance sheet date, less estimated future expenditures to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Prima did not recognize any impairment loss during the three-year period ended December 31, 2003.

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141, Business Combinations, and SFAS No. 142, Goodwill and Other Intangible Assets, to companies in the extractive industries, including oil and gas companies. The issue is whether the Financial Accounting Standards Board (FASB) intended to require companies to classify the costs of mineral rights held under lease or other contractual arrangements associated with extracting oil and gas as intangible assets in balance sheets, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, we have included the costs of such mineral rights associated with extracting oil and gas as a component of our investments in oil and gas properties. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify the costs associated with mineral rights as a separate category of intangible assets on balance sheets, we would be required to reclassify approximately $27 million at December 31, 2003 and $26 million at December 31, 2002 out of oil and gas properties and into a separate intangible assets line item. Our results of operations and cash flows would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full-cost accounting rules.

Other Property and Equipment

Other (non-oil and gas) property and equipment is recorded at cost. Renewals and betterments that substantially extend the useful lives of the assets are capitalized. Maintenance and repairs are expensed when incurred. Depreciation is provided using the straight-line method over the estimated useful lives of the assets, ranging from three to 15 years. Such long-lived assets are evaluated for impairment to determine if current circumstances and market conditions indicate that the carrying amount of an asset may not be recoverable. Prima did not recognize any impairment loss during the three-year period ended December 31, 2003.

Asset Retirement Obligations

Effective January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*. SFAS No. 143 provides that, if the fair value for an asset retirement obligation can be reasonably estimated, the liability should be recognized in the period in which it is incurred. Oil and gas producing companies typically incur such liabilities upon drilling or acquiring wells. Under the method prescribed by SFAS No. 143, an asset retirement obligation is recorded as a liability at its estimated present value at the asset s inception, with an offsetting charge to property cost. The corresponding property cost, less the estimated undiscounted salvage value, is then included in the calculation of depletion cost for oil and gas properties. Periodic accretion of discount of the estimated liability is also recorded in the income statement. Prior to adoption of SFAS No. 143, we accrued for any estimated asset retirement obligation, net of estimated salvage value, as part of our calculation of depletion, depreciation and amortization. Under this method, the estimated net cost of the obligation would be recognized over the life of the property on a unit-of-production basis, with the estimated obligation netted in property cost as part of the accumulated depreciation, depletion and amortization balance. Based on our experience that salvage values have generally equaled or exceeded abandonment costs for the types of properties that Prima has owned to date, such net costs have been negligible.

Natural Gas Imbalances

Prima utilizes the accrual method of accounting for natural gas revenues whereby revenues are recognized as the Company s entitlement share of gas is produced and sold based on its net revenue interests in the properties. The Company records a receivable (payable) to the extent it receives less (more) than its proportionate share of gas revenues. Imbalance positions were not significant at the end of 2003 or 2002.

Oilfield Services and Operator Fees

Fees earned from providing oilfield services and operating wells for third parties are recorded when the services are performed. Fees charged non-affiliates for oilfield services are recognized as income. Fees charged non-affiliates for operating oil and gas properties are recorded as a reduction of general and administrative expenses, unless fees exceed total costs, in which case any excess is recorded as revenue.

Income Taxes

Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income tax assets and liabilities represent the estimated future tax return consequences of those differences, which will either be taxable or deductible when the assets and liabilities are recovered or settled. Deferred income taxes are also recognized for tax credits that are available to offset future federal income taxes. Deferred income taxes are measured by applying currently-enacted tax rates.

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Derivative Instruments and Hedging Activities

Prima periodically enters into derivative contracts to mitigate risks associated with downward price movements in benchmark NYMEX gas and oil prices or, in the case of basis swaps, to protect the Company from increases in the differential between NYMEX and Rocky Mountain gas prices. These derivatives contracts generally represent cash flow hedges that are determined to be qualifying or non-qualifying for hedge accounting treatment in accordance with the provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. Derivatives may be entered into in an effort to enhance profitability, as well as mitigate risks.

SFAS 133 prescribes that the fair value of all derivatives should be recognized as either assets or liabilities on the balance sheet. SFAS 133 also establishes requirements for designation and documentation of hedging relationships and ongoing effectiveness assessments. Hedge effectiveness is measured based on the relative changes over time in the fair values of a derivative and the related hedged item. If a cash flow hedge qualifies for hedge accounting under SFAS 133, and is so designated by the Company, changes in the fair value of the derivative are recorded initially in other comprehensive income and then recognized in the income statement when the hedged item affects earnings. If a derivatives position does not qualify for hedge accounting under SFAS 133, or if the Company so elects, changes in the fair value of the derivative are immediately recognized in earnings. Prima generally elects to use hedge accounting when conditions to do so are satisfied.

The Company has determined that pursuant to SFAS 133 requirements, and based on its current sources of oil and gas production, that swaps, collars, puts or floors that are based on NYMEX oil prices or Rocky Mountain gas prices qualify for hedge accounting. Derivatives based on NYMEX gas prices will not so qualify unless corresponding transactions are entered into to hedge basis differentials between NYMEX and Rocky Mountain indices. In addition, stand-alone basis differential swaps, sales of call options, and positions that do not mitigate risk do not qualify for hedge accounting.

The adoption of SFAS 133 as of January 1, 2001 resulted in the recognition of a current asset of $1,241,000, a current liability of $549,000, net-of-tax cumulative effect adjustments reducing other comprehensive income by $129,000, and an increase in net income by $611,000. The $611,000 is reflected as the cumulative effect of a change in accounting principle in the December 31, 2001 financial statements.

Stock-Based Compensation

At December 31, 2003, Prima had stock-based compensation plans in effect, which are more fully described in Note 9. The Company accounts for stock-based compensation using the intrinsic value recognition and measurement principles prescribed in Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees (APB No. 25) and related interpretations. No stock-based compensation expense for employees or non-employee directors is reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant.

For disclosure purposes, the fair value of options is measured at the date of grant using the Black-Scholes option valuation model, which was developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. Such option valuation models also require the input of highly subjective assumptions, including the projected life of the options and expected stock price volatility. Because options issued under Prima s stock-based compensation plans have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the estimated fair value, these valuation models do not necessarily provide a reliable measure of the fair value of such stock options.

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The following assumptions were utilized to estimate the fair values of options granted during the three years ended December 31, 2003, using the Black-Scholes Valuation Model:

	2003	2002	2001
Expected dividend yield	0%	0%	0%
Expected price volatility	48%	41%	43%
Risk free interest rate	3.5%	2.9%	5.1%
Expected life of options (in years)	6	6	6

Based on the above, the estimated weighted average fair values of employee stock options granted during 2003, 2002 and 2001 were $12.05, $11.52 and $16.04 respectively. The weighted average fair values of non-employee directors options granted during 2003, 2002 and 2001 were $11.81, $9.04 and $12.49, respectively.

For purposes of pro forma disclosures, the estimated fair values of option grants are amortized to expense over the options vesting periods. The following table illustrates the effects on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS No. 123.

	2003	2002	2001
Net Income			
As reported	$23,795,000	$5,230,000	$23,768,000
Add stock-based employee compensation expense included in reported net income, net of related tax effects			
Less stock-based employee compensation expense determined under fair value based method for all awards, net of related income tax effects	1,004,000	888,000	409,000
Pro forma	$22,791,000	$4,342,000	$23,359,000
Basic Net Income per Share			
As reported	$ 1.85	$ 0.41	$ 1.87
Pro forma	$ 1.78	$ 0.34	$ 1.83
Diluted Net Income per Share			
As reported	$ 1.82	$ 0.40	$ 1.80
Pro forma	$ 1.74	$ 0.33	$ 1.77

Earnings Per Share

Basic net income per share is computed by dividing net income by the weighted average common shares outstanding during the period. Diluted net income per share includes the potential dilution that could occur upon exercise of the options to acquire common stock described in Note 9, computed using the treasury stock method. The treasury stock method assumes that the increase in the number of shares issued is reduced by the number of shares that could have been repurchased by the Company with the proceeds from exercise of the options (assuming an acquisition cost equal to the average market price of the common shares during the reporting period).

New Accounting Pronouncements

In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity to improve the accounting for certain financial instruments that, under previous guidance, issuers could account for as equity. SFAS No. 150 requires that those instruments be classified as liabilities in statements of financial position. SFAS No. 150 does not apply to features embedded in a financial instrument that is not a derivative in its entirety. In addition to its requirements for the classification and measurement of financial instruments within its scope, SFAS No. 150 also requires disclosures about alternative ways of settling the instruments and the capital structure of entities, all of whose shares are mandatorily redeemable. Most of the guidance in Statement 150 is effective for all financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. As we have no such financial instruments, we do not anticipate any impact on our financial position or results of operations upon adoption.

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2. AVAILABLE-FOR-SALE SECURITIES

Prima s available-for-sale securities are comprised of marketable equity securities, including closed-end bond funds. During the years ended December 31, 2003 and 2002, the Company sold securities with a market value of $1,177,000 and $929,000, which resulted in realized gains of $66,000 in both years. The Company determined that there was an other-than-temporary decline in the fair market value of an individual security in its portfolio at the end of 2002 and, accordingly, an impairment loss of $91,000 was recognized that year. Other net unrealized losses on securities are included in accumulated other comprehensive income, net of deferred income taxes of $17,000 and $(16,000), respectively, at December 31, 2003 and 2002. The changes in net unrealized losses on securities for the years ended December 31, 2003 and 2002 were as follows:

	2003	2002
Net unrealized gain (loss), end of year	$ 45,000	$(44,000)
Net unrealized (loss), beginning of year	(44,000)	(53,000)
Net change in unrealized gain (loss)	$ 89,000	$ 9,000

The components of fair value as of December 31, 2003 and 2002 were as follows:

	2003	2002
Cost (including reinvested distributions)	$1,229,000	$1,788,000
Gross unrealized gains	61,000	46,000
Gross unrealized losses	(16,000)	(90,000)
Fair value	$1,274,000	$1,744,000

3. ASSET RETIREMENT OBLIGATIONS

Our asset retirement obligations primarily represent the estimated present value of the amounts we project will be incurred to plug, abandon and remediate our oil and gas properties at the end of their productive lives, in accordance with applicable laws and regulations. Our adoption of SFAS No. 143 as of January 1, 2003 resulted in the recognition of an increase in the carrying value of our oil and gas properties of $2,252,000, an increase in our deferred tax liability of $217,000, an increase in other non-current liabilities of $1,632,000, and a net-of-tax adjustment increasing net income by $403,000, which was recorded as the cumulative effect of a change in accounting principle. The estimated pro forma effects on periods prior to 2003 were not material. A reconciliation of Prima s recorded liability at the end of

2003 for asset retirement obligations is as follows:

Upon adoption at January 1, 2003	$1,632,000
Liabilities incurred	235,000
Liabilities settled	
Accretion expense	149,000
Revision to estimate	(113,000)
	$1,903,000

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4. EARNINGS PER SHARE AND COMMON STOCK

The following table reconciles the numerator and denominator used in the calculation of basic and diluted net income per share.

	Income (Numerator)	Shares (Denominator)	Per Share Amount
Year Ended December 31, 2003:			
Basic Net Income per Share	$23,795,000	12,824,123	$ 1.85
Effect of Stock Options		237,497	
Diluted Net Income per Share	$23,795,000	13,061,620	$ 1.82
Year Ended December 31, 2002:			
Basic Net Income per Share	$ 5,230,000	12,770,716	$ 0.41
Effect of Stock Options		450,660	
Diluted Net Income per Share	$ 5,230,000	13,221,376	$ 0.40
Year Ended December 31, 2001:			
Basic Net Income per Share	$23,768,000	12,731,181	$ 1.87
Effect of Stock Options		487,970	
Diluted Net Income per Share	$23,768,000	13,219,151	$ 1.80

In January 2001, Prima s Board of Directors approved a repurchase program of up to 5% of the Company s common stock then outstanding or approximately 640,000 shares. In 2003, the Company purchased 111,868 treasury shares for $2,111,000. The total of 348,406 shares repurchased to date represents approximately 2.7% of the shares then outstanding, or 54% of the shares authorized for repurchase under the program. As of December 31, 2003, approximately 291,000 shares remained subject to repurchase under this authorization.

5. DERIVATIVES CONTRACTS

Prima periodically enters into derivative contracts to mitigate risks associated with downward price movements in benchmark NYMEX oil and gas prices or, in the case of basis swaps, to protect the Company from increases in the differential between NYMEX and Rocky Mountain gas prices. While such hedges can reduce the adverse effects of oil and gas price declines, they may also limit the benefits of price increases. These derivatives contracts generally represent cash flow hedges that are determined to be qualifying or non-qualifying for hedge accounting treatment in accordance with the provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. Derivatives may be entered into in an effort to enhance profitability, as well as mitigate risks.

The Company has entered into various cash flow hedges related to its oil and gas production. Some of these derivatives have qualified for hedge accounting, while others have been non-qualifying. The derivative instruments not qualifying for hedge accounting have principally been NYMEX gas swaps for which we did not enter into corresponding swaps for Rocky Mountain basis differentials. The following table summarizes the income statement effects of these transactions for the years shown:

	2003	2002	2001
Realized gains (losses) on derivatives qualifying for hedge accounting, included in oil and gas sales	$ 414,000	$ (458,000)	$3,381,000
Realized gains on non-qualifying hedges	1,636,000	1,546,000	2,057,000
Unrealized gains (losses) on non-qualifying hedges	684,000	(4,464,000)	4,378,000
Aggregate amounts reported on consolidated statements of income	$2,734,000	$(3,376,000)	$9,816,000

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In addition, $427,000 of realized losses on closed derivatives positions that qualified for hedge accounting were included in other comprehensive income at December 31, 2003 and will be included as a reduction of oil and gas sales in 2004, as the related production months occur.

As of December 31, 2003, Prima reported a net current liability of $1,983,000, representing the fair value of its open derivatives contracts at that date. These positions are summarized below:

Time Period	Market Index	Total Volumes (MMBtu or Bbls)	Contract Price	Fair Value
Natural Gas:				
February March 2004	NYMEX	600,000	$ 6.38	$ 172,000
February November 2004	CIG	3,500,000	4.00	(2,030,000)
Oil:				
February June 2004	NYMEX	75,000	30.08	(125,000)
Total Net Fair Value				$(1,983,000)

Oil and gas prices are volatile and the market value of these derivatives changes as the underlying commodity futures prices change. Actual gains or losses realized will depend on the applicable futures prices in effect at the time such positions are closed. Mark-to-market adjustments could result in significant earnings volatility.

6. INCOME TAXES

The provision for income taxes consists of the following components:

	2003	2002	2001
Current:			
Federal	$ 4,713,000	$1,636,000	$ 2,067,000
State	386,000	166,000	(275,000)
	5,099,000	1,802,000	1,792,000
Deferred:			
Federal	4,090,000	(429,000)	8,732,000
State	412,000	(35,000)	782,000

	4,502,000	(464,000)	9,514,000
Tax credits	2,131,000	(513,000)	(391,000)
Provision for income taxes	$11,732,000	$ 825,000	$10,915,000

During 2003, 2002 and 2001, the Company recognized income tax deductions of $5,171,000, $3,375,000 and $1,979,000, respectively, from the exercise of nonqualified stock options. Stockholders equity has been credited in the amount of $1,913,000, $1,250,000 and $732,000 for the income tax benefit of these deductions. The provisions for income taxes in 2003 and 2001 included $217,000 and $265,000, respectively, of expense that was netted in the cumulative effects of changes in accounting principle. During 2001, Prima recognized taxable income of $207,000 from short-swing profits and stockholders equity was reduced in the amount of $77,000 for the current income tax expense associated with this income.

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The significant components of deferred tax assets and liabilities included on the balance sheet are as follows:

	2003	2002
Deferred Tax Assets:		
Minimum tax credit carryforwards	$ 110,000	$ 2,241,000
State income taxes	764,000	648,000
Derivatives	734,000	83,000
Asset retirement obligations	704,000	
Other	247,000	310,000
Total Deferred Tax Assets	2,559,000	3,282,000
Deferred Tax Liabilities:		
Intangible drilling costs	28,192,000	22,666,000
Depreciation	843,000	742,000
Land held for investment	370,000	370,000
Other	1,000	589,000
Total Deferred Tax Liabilities	29,406,000	24,367,000
Net Deferred Tax Liabilities	$26,847,000	$21,085,000

A reconciliation of income tax computed at the federal statutory tax rate to the Company s effective tax rate follows:

	2003	2002	2001
Federal statutory income tax rate	34.0%	34.0%	34.0%
Percentage depletion	(1.4)	(6.3)	(1.2)
Section 29 credits		(15.8)	(3.0)
State taxes, net of federal benefits	1.4	1.5	1.0
Other	(1.0)	0.3	0.7
Effective tax rate	33.0%	13.7%	31.5%

At December 31, 2003, Prima had minimum tax credit carryforwards of approximately $110,000, which may be carried forward indefinitely.

7. SEGMENT INFORMATION

The Company organizes its activities in operating segments that consist of 1) the acquisition, exploration, development and operation of oil and gas properties and the development, production and sale of oil and natural gas and 2) providing oilfield services for wells which it operates and for third parties. The Company s activities have been conducted primarily in the Rocky Mountain region of the United States, which is one geographic area.

The information below presents the operating segment data for the Company on the basis used by management in deciding how to allocate resources and in assessing performance. The following table sets forth revenues, operating earnings before income taxes, identifiable assets, depreciation, depletion and amortization expense and capital expenditures for the years ended December 31, 2003, 2002 and 2001. This information is presented on the basis used by management, which is the same basis used in the preparation of the Company s consolidated financial statements.

	2003	2002	2001
Revenues			
Oil & gas (including derivative effects)	$ 60,942,000	$ 22,867,000	$ 50,983,000
Oilfield services	11,333,000	10,325,000	12,207,000
	72,275,000	33,192,000	63,190,000
Corporate	635,000	597,000	1,214,000
Intersegment eliminations	(2,756,000)	(1,999,000)	(4,117,000)
Per financial statements	$ 70,154,000	$ 31,790,000	$ 60,287,000
Operating Earnings			
Oil & gas (including derivative effects)	$ 36,584,000	$ 7,965,000	$ 34,913,000
Oilfield services	1,746,000	1,094,000	2,083,000
	38,330,000	9,059,000	36,996,000
Corporate	(2,932,000)	(2,906,000)	(2,624,000)
Intersegment eliminations	(491,000)	(98,000)	(565,000)
Per financial statements	$ 34,907,000	$ 6,055,000	$ 33,807,000
Identifiable Assets			
Oil & gas	$112,267,000	$ 95,300,000	$100,200,000
Oilfield services	5,942,000	6,322,000	7,218,000
	118,209,000	101,622,000	107,418,000
Corporate	59,008,000	40,305,000	28,026,000
Per financial statements	$177,217,000	$141,927,000	$135,444,000
Depreciation, Depletion and Amortization			
Oil & gas	$ 14,956,000	$ 9,710,000	$ 9,190,000
Oilfield services	977,000	832,000	767,000

	15,933,000	10,542,000	9,957,000
Corporate	81,000	256,000	272,000
Per financial statements	$ 16,014,000	$ 10,798,000	$ 10,229,000
Capital Expenditures			
Oil & gas	$ 26,856,000	$ 22,252,000	$ 35,248,000
Oilfield services	1,358,000	868,000	1,539,000
	28,214,000	23,120,000	36,787,000
Corporate	65,000	274,000	419,000
Per financial statements	$ 28,279,000	$ 23,394,000	$ 37,206,000

Total revenue by operating segment includes both sales to unaffiliated customers, as reported in the Company s consolidated income statement, and intersegment sales that are eliminated in consolidation, which represent oilfield services provided for Company-operated wells. Oilfield services revenue is priced and accounted for consistently for both unaffiliated and intersegment sales.

Identifiable assets by operating segment are those assets that are used in the Company s operations in each segment. Corporate assets are principally cash, cash equivalents and available-for-sale securities.

Following is a table summarizing the percentage of sales made to each customer that accounted for over 10% of the Company s consolidated revenues. Although the loss of any of these customers could have a material adverse effect on Prima, the Company believes it would be able to locate other customers to purchase its production.

	2003	2002	2001
Duke Energy Field Services, LLC	27%	33%	31%
Western Gas Resources, Inc.	27	*	*
Valero Energy Corporation	17	29	16

* Less than 10%

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8. COMMITMENTS AND CONTINGENCIES

Prima entered into a seven-year office space lease for its Denver headquarters effective December 1, 2000. Related office lease expense totaled $316,000, $295,000 and $282,000 for the years ended December 31, 2003, 2002 and 2001, respectively. Future minimum annual rentals under this non-cancelable operating lease are as follows:

Year ending December 31, 2004	$ 317,000
Year ending December 31, 2005	317,000
Year ending December 31, 2006	317,000
Year ending December 31, 2007	290,000
	$1,241,000

The Company is aware of various legal and regulatory proceedings in several states, including Colorado and Wyoming, concerning calculation of royalties and production taxes payable by oil and gas producers. Prima is not a named party in any such proceeding, but could potentially be impacted by the outcome of one or more of them. No assessment can be made at the present time as to the likelihood or magnitude of any such impact.

From time to time, the Company may be involved in litigation that arises in the ordinary course of business operations. As of the date of this report, the Company is not a party to any litigation that it believes could reasonably be expected to have a material adverse effect on its business or results of operations.

9. BENEFIT PLANS

Employee Stock Option Plans

Under Prima s 1993 Stock Incentive Plan and 2001 Stock Incentive Plan, 2,650,000 shares of the Company s common stock were reserved for issuance pursuant to options granted to key employees at exercise prices no less than fair market value on the dates of grant. The 1993 Plan terminated in September of 2003. Options granted to date under the plans vest ratably over three to five years, and expire ten years from the date of grant. A summary of options granted, exercised and outstanding during the three years ended December 31, 2003 is as follows:

	Number of Shares	Weighted Average Exercise Prices
Balance at December 31, 2000	911,975	$ 5.49
Granted during 2001	216,000	32.53
Exercised in 2001	(86,425)	5.01
Forfeited in 2001	(3,600)	9.39

Outstanding at December 31, 2001	1,037,950	11.14
Granted during 2002	171,500	25.36
Exercised in 2002	(174,125)	4.79
Forfeited in 2002	(109,000)	25.91
Outstanding at December 31, 2002	926,325	13.20
Granted during 2003	130,750	23.92
Exercised in 2003	(226,000)	4.84
Forfeited in 2003	(9,500)	28.92
Outstanding at December 31, 2003	821,575	16.96
Exercisable at December 31, 2001	648,625	5.01
Exercisable at December 31, 2002	601,092	7.37
Exercisable at December 31, 2003	519,583	11.26

At the end of 2003, the number of shares of common stock remaining available for future option grants under these plans totaled 1,039,750.

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Non-Employee Directors Stock Option Plan

Under Prima s Non-Employee Directors Stock Option Plan, 225,000 shares of Prima s common stock were reserved for issuance pursuant to options granted to non-employee directors at exercise prices no less than fair market value on the dates of grant. This plan provides for each non-employee director to receive a grant of 22,500 options on the effective date of the plan, or upon election as a non-employee director if later. On each anniversary date of the initial grant, an additional 5,625 options are granted to each non-employee director. Options vest ratably over five years and expire ten years from the date of grant. A summary of options granted, exercised and outstanding during the three years ended December 31, 2003 is as follows:

	Number of Shares	Weighted Average Exercise Prices
Balance at December 31, 2000	146,250	$ 14.94
Granted during 2001	22,500	25.49
Exercised during 2001	(10,125)	7.02
Forfeited during 2001	(23,625)	10.86
Outstanding at December 31, 2001	135,000	17.57
Granted during 2002	22,500	20.52
Exercised during 2002		
Forfeited during 2002		
Outstanding at December 31, 2002	157,500	17.99
Granted during 2003	22,500	23.49
Exercised during 2003	(22,500)	6.67
Forfeited during 2003		
Outstanding at December 31, 2003	157,500	20.39
Exercisable at December 31, 2001	42,750	11.74
Exercisable at December 31, 2002	69,750	13.99
Exercisable at December 31, 2003	78,750	17.69

At the end of 2003, the number of shares of common stock remaining available for future option grants under this plan was 30,375.

Summary of Outstanding Options

The following table summarizes information about stock options outstanding at December 31, 2003 on a combined basis for the employee and non-employee directors plans:

	Stock Options Outstanding			Stock Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/03	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at 12/31/03	Weighted-Average Exercise Price
$4.41 9.83	455,575	3.5	$ 6.00	447,250	$ 5.94
16.18	5,625	8.6	16.18	1,125	16.18
20.19 25.83	199,000	8.1	22.88	37,525	22.90
26.38 33.25	318,875	7.7	30.63	112,433	31.58
	979,075		17.51	598,333	11.84

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Employee Stock Ownership Plan

The Company has an Employee Stock Ownership Plan (ESOP), which is administered pursuant to a Trust Agreement. The ESOP is qualified under Section 401(a) of the Internal Revenue Code of 1986, as amended, and is for the benefit of all eligible employees of the Company. Company contributions are payable at a minimum rate of 5% of eligible salaries during the ESOP s fiscal year ending September 30, and are generally made quarterly. Through September 30, 1993, the ESOP provided for contributions to be used to purchase Prima common stock on the open market. Effective October 1, 1993, the ESOP was amended to allow fully-vested employees the option to direct the Trustees to diversify a portion of their investments by selling a limited portion of Prima common stock held in their account and investing the proceeds, as well as new contributions, in various diversified investment options. The ESOP benefits all full-time employees and provides for vesting in increments over six years. For the years ended December 31, 2003, 2002 and 2001, Prima expensed $363,000, $339,000 and $316,000, respectively, for its contributions to the ESOP.

10. TRANSACTIONS WITH RELATED PARTIES

The Company acquired oil and gas leases covering 26,680 net undeveloped acres in June 2000 from a company controlled by a director of Prima for a negotiated price of $12 per net acre, or a total of approximately $320,000. Additional acreage in the same general area was subsequently acquired from this director at cost. The aggregate amounts paid for these property interests, including the initial acquisition, totaled $3,000 in 2002, $290,000 in 2001 and $376,000 in 2000. The director, or entities controlled by him, reserved an overriding royalty interest in all acquired leases of 3% or less, depending on the net revenue interest of the leases, proportionately reduced to the working interest acquired. The disinterested members of the Board of Directors approved the transactions.

One of the Company s directors and one officer has participated, individually or through controlled entities, in oil and gas properties in which Prima has an interest. These working interest participations have been in prospects or properties originated or acquired by the Company. In some cases, the interests sold to affiliated and non-affiliated participants were sold on a promoted basis requiring these participants to pay a disproportionate share of well costs. All participations by directors and officers have been on terms no less favorable to the Company than believed to be obtainable from non-affiliated participants. Such joint participations may occur again from time to time in the future. All participations by officers or directors have been and will continue to be approved by the disinterested members of the Company s Board of Directors. At any point in time, there may be receivables or payables with officers and directors that arise in the ordinary course of business, as a result of participations in jointly held oil and gas properties. Amounts due to or from officers and directors resulting from billings of joint interest costs or receipts of production revenues on these properties are handled on terms pursuant to standard industry joint operating agreements which are no more or less favorable than similar transactions with unrelated parties.

Prima is a 6% limited partner in a real estate limited partnership that owns approximately 22 acres of undeveloped land in Phoenix, Arizona for investment. One of the general partners of the partnership is a company controlled by a brother of the Company s president. Prima participated on the same basis as the other limited partners. The disinterested members of the Company s Board of Directors approved the transaction. During the three years ended December 31, 2003, Prima did not make any capital contributions to the partnership, nor did it receive any distributions therefrom. During 2003, the Company recorded a $116,000 valuation impairment to reduce the carrying value of the asset from $257,000 to $141,000, to reflect expected net proceeds from a pending sales agreement with an unrelated third party.

11. SALE OF ASSETS

On March 5, 2002, Prima sold all of its producing wells in the Stones Throw coalbed methane project in the northern Powder River Basin, along with associated gathering system facilities and approximately 35,000 net undeveloped acres in the immediate vicinity. Net proceeds from the transaction totaled $13,514,000 after normal closing adjustments and were credited to the carrying value of oil and gas properties. These properties accounted for

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approximately 6.1% of Prima s total estimated proved oil and gas reserves and 4.5% of the related estimated present value of future net cash flows before income taxes, as of the end of 2001. The producing wells sold accounted for approximately 17% of Prima s net oil and gas production and 8% of its total oil and gas sales revenue before hedging effects during the first two months of 2002, and approximately 11% of net oil and gas production and 5% of total oil and gas sales revenue before hedging effects for the year 2001.

12. SUPPLEMENTARY OIL AND GAS INFORMATION

Prima s oil and gas operations are conducted entirely in the United States, primarily in the Rocky Mountain region. Certain information concerning these activities follows:

Costs Incurred Costs incurred in oil and gas property acquisition, exploration and development activities, and related depletion per equivalent units of production were as follows:

	2003	2002	2001
Development costs	$19,776,000	$15,157,000	$31,114,000
Exploration costs	6,730,000	5,685,000	1,620,000
Acquisition costs:			
Unproved properties	326,000	876,000	2,114,000
Proved properties	24,000	534,000	400,000
Total before asset retirement obligations	26,856,000	22,252,000	35,248,000
Asset retirement obligations	122,000		
Total	$26,978,000	$22,252,000	$35,248,000
Depletion cost per equivalent Mcf of production	$ 0.97	$ 0.92	$ 0.77

Costs Not Being Amortized Oil and gas property costs not being amortized at December 31, 2003 consisted of $27,317,000 of leasehold costs and well costs for wells under evaluation. The Company anticipates that substantially all unevaluated costs will be classified as evaluated costs within three years.

Results of Operations Results of operations for oil and gas producing activities were as follows:

	2003	2002	2001
Revenues			
Oil and gas sales	$58,622,000	$25,785,000	$44,548,000

Gains (losses) on derivative instruments, net	2,320,000	(2,918,000)	6,435,000
	60,942,000	22,867,000	50,983,000
Expenses			
Depletion of oil and gas properties	14,956,000	9,710,000	9,190,000
Lease operating expense	3,619,000	3,076,000	3,295,000
Ad valorem and production taxes	5,783,000	2,116,000	3,344,000
Impairment of natural gas swap			241,000
	24,358,000	14,902,000	16,070,000
Income before income taxes	36,584,000	7,965,000	34,913,000
Income tax expense	12,073,000	1,083,000	10,998,000
Income from oil and gas producing activities	$24,511,000	$ 6,882,000	$23,915,000

Supplemental Oil and Gas Reserve Information (Unaudited)

The reserve information presented below is based on estimates of net proved reserves as of December 31, 2003, 2002 and 2001 that were prepared by Prima s engineers and audited by Netherland, Sewell and Associates, Inc.,

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independent petroleum engineers. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures. Oil and gas reserve engineering should be recognized as a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimates is a function of the quality of available data and engineering and geological interpretation and judgment. Results of drilling, testing and production after the date of the estimate may require revisions. Accordingly, reserve estimates are often materially different from the quantities of oil and natural gas that are ultimately produced.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those proved reserves expected to be recovered through existing wells with existing equipment and operating methods.

Analyses of Changes in Proved Reserves The following table sets forth information regarding the Company s estimated net total proved and proved developed oil and gas reserve quantities:

	2003		2002		2001	
	Oil (Mbbls)	**Gas (MMcf)**	**Oil (Mbbls)**	**Gas (MMcf)**	**Oil (Mbbls)**	**Gas (MMcf)**
Proved reserves:						
Beginning of year	3,944	87,440	3,394	115,222	3,729	154,172
Purchases of oil and gas reserves in place	44	355	5	899		2,388
Net exchanges of oil and gas reserves in place		(3,686)		(331)	10	(2,051)
Revisions of previous estimates	370	17,162	188	(17,744)	(611)	(44,495)
Extensions, discoveries and other additions	1,009	8,809	730	5,665	697	14,485
Production	(401)	(13,015)	(373)	(8,343)	(431)	(9,277)
Sales of oil and gas reserves in place		(1,065)		(7,928)		
End of year	4,966	96,000	3,944	87,440	3,394	115,222
Proved developed reserves:						
Beginning of year	3,115	66,245	2,949	69,168	2,945	77,385
End of year	3,306	67,983	3,115	66,245	2,949	69,168

SFAS No. 69, Disclosures about Oil and Gas Producing Activities, prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company has followed these guidelines, which are briefly discussed below.

Future cash inflows and future production and development costs are determined by applying benchmark prices and costs, adjusted for applicable transportation, quality and other basis differential variances for the Company s properties that were in effect at year-end to the year-end estimated quantities of oil and gas to be produced in the future. Each property operated is also charged with overhead in the estimated reserve calculation. Estimated future income taxes are computed using current statutory income tax rates, including consideration for estimated future statutory depletion. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

Future operating costs are determined based on estimates of expenditures to be incurred in developing and producing the proved oil and gas reserves in place at the end of the period, using year-end costs and assuming

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continuation of existing economic conditions, plus Company overhead incurred by the central administrative office attributable to operating activities.

The assumptions used to compute the standardized measure are those prescribed by the FASB and the Securities and Exchange Commission. These assumptions do not necessarily reflect the Company s expectations of actual revenues to be derived from those reserves, nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates are the basis for the valuation process. The following average prices, which reflect all appropriate adjustments for transportation, quality and other basis differential factors, were used in the calculation of the standardized measure at the end of each year shown:

	2003	2002	2001
Natural gas (per Mcf)	$ 4.95	$ 2.64	$ 1.94
Oil (per barrel)	32.88	31.30	19.71

Standardized Measure The following table presents the standardized measure of discounted future net cash flows related to proved oil and gas reserves.

	2003	2002	2001
Future cash inflows	$ 638,404,000	$354,617,000	$290,303,000
Future production costs	(162,617,000)	(93,357,000)	(90,816,000)
Future development costs	(65,486,000)	(39,484,000)	(42,863,000)
Future net cash flows	410,301,000	221,776,000	156,624,000
10% discount factor	(170,501,000)	(92,933,000)	(64,719,000)
Discounted future income taxes	(80,821,000)	(37,564,000)	(25,104,000)
Standardized measure of discounted future net cash flows	$ 158,979,000	$ 91,279,000	$ 66,801,000

A summary of changes in the standardized measure of discounted future net cash flows is as follows:

	2003	2002	2001
Standardized measure of discounted future net cash flows, beginning of year	$ 91,279,000	$ 66,801,000	$ 371,121,000
Sales of oil and gas, net of production	(48,806,000)	(21,136,000)	(34,057,000)

costs and production taxes			
Net changes in prices and production costs	88,726,000	42,497,000	(469,638,000)
Extensions, discoveries, and improved recovery, less related costs	19,951,000	9,728,000	8,680,000
Development costs incurred during the year	10,490,000	7,518,000	19,920,000
Changes in estimated future development costs	(11,620,000)	(3,313,000)	11,381,000
Revisions of previous quantity estimates	41,531,000	(5,089,000)	(46,997,000)
Purchases of reserves in place	904,000	640,000	1,088,000
Net exchanges of reserves in place	(1,215,000)	(403,000)	(7,429,000)
Sales of reserves in place	(551,000)	(4,056,000)	
Other	(1,337,000)	1,360,000	(4,207,000)
Accretion of discount	12,884,000	9,191,000	37,112,000
Net changes in future income taxes	(43,257,000)	(12,459,000)	179,827,000
Standardized measure of discounted future net cash flows, end of year	$158,979,000	$ 91,279,000	$ 66,801,000

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13. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited financial data for each quarter for the years ended December 31, 2003 and 2002.

	Three Months Ended			
	12/31/03	9/30/03	6/30/03	3/31/03
Year Ended December 31, 2003				
Revenues	$19,875,000	$18,229,000	$16,440,000	$15,610,000
Gross profit (1)	15,208,000	14,427,000	12,381,000	11,591,000
Income before income tax	9,782,000	9,838,000	7,858,000	7,429,000
Net income	6,557,000	6,593,000	5,263,000	5,382,000
Basic net income per share (2)	0.51	0.51	0.41	0.42
Diluted net income per share (2)	0.50	0.50	0.40	0.41

	Three Months Ended			
	12/31/02	9/30/02	6/30/02	3/31/02
Year Ended December 31, 2002				
Revenues	$10,233,000	$7,432,000	$8,718,000	$ 5,407,000
Gross profit (1)	7,412,000	4,364,000	5,490,000	2,245,000
Income before income tax	3,421,000	1,226,000	2,470,000	(1,062,000)
Net income	2,936,000	1,026,000	1,990,000	(722,000)
Basic net income per share (2)	0.23	0.08	0.16	(0.06)
Diluted net income per share (2)	0.22	0.08	0.15	(0.06)

(1) Gross profit is computed as the excess of oil and gas sales, gains or losses on derivatives instruments, and revenues from oilfield services over operating expenses. Operating expenses include lease operating expense, ad valorem and production taxes, and oilfield services expenses.

(2) The sum of the individual quarterly net income (loss) per share may not agree with year-to-date net income (loss) per share as each period s computation is based on the weighted average number of common shares outstanding during the period.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Prima Energy Corporation has duly caused this Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized, in Denver, Colorado on the 12th day of March, 2004.

PRIMA ENERGY CORPORATION

By: /s/ Richard H. Lewis
Richard H. Lewis, President

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report on Form 10-K has been signed below by the following persons in the capacities indicated and on the dates indicated.

Signature	Title	Date
/s/ Richard H. Lewis Richard H. Lewis	Chairman of the Board and President (Principal Executive Officer)	March 12, 2004
/s/ Neil L. Stenbuck Neil L. Stenbuck	Executive Vice President - Finance, Treasurer and Director (Principal Financial Officer)	March 12, 2004
/s/ Sandra J. Irlando Sandra J. Irlando	Vice President - Accounting (Principal Accounting Officer)	March 12, 2004
/s/ James R. Cummings James R. Cummings	Director	March 12, 2004
/s/ Douglas J. Guion Douglas J. Guion	Director	March 12, 2004
/s/ Catherine J. Paglia Catherine J. Paglia	Director	March 12, 2004
/s/ George L. Seward George L. Seward	Director	March 12, 2004

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Exhibit No.	Document
3.1	Certificate of Incorporation of Prima Energy Corporation, Delaware, as filed August 18, 1988. (Incorporated by reference to Registration of Securities of Certain Successor Issuers on Form 8-B dated January 20, 1989.)
3.2	Certificate of Amendment of Certificate of Incorporation of Prima Energy Corporation filed May 1, 1989. (Incorporated by reference to Annual Report on Form 10-K for Prima Energy Corporation for the year ended June 30, 1989.)
3.3	Bylaws of Prima Energy Corporation. (Incorporated by reference to Registration of Securities of Certain Successor Issuers on Form 8-B dated January 20, 1989.)
3.4	Certificate of Amendment of the Certificate of Incorporation of Prima Energy Corporation. (Incorporated by reference to Quarterly Report on Form 10-Q for Prima Energy Corporation for the quarter ended June 30, 1997.)
3.5	Certificate of Amendment of the Certificate of Incorporation of Prima Energy Corporation. (Incorporated by reference to Quarterly Report on Form 10-Q for Prima Energy Corporation for the quarter ended September 30, 2000.)
3.6	Certificate of Amendment of the Certificate of Incorporation of Prima Energy Corporation. (Incorporated by reference to Quarterly Report on Form 10-Q for Prima Energy Corporation for the quarter ended June 30, 2001.)
4.1	Rights Agreement dated as of May 23, 2001, between Prima Energy Corporation and Computershare Trust Company, Inc., as Rights Agent, including the form of Certificate of Designation, Powers, Preferences and Rights of Series A Participating Preferred Stock dated May 29, 2001, the Form of Right Certificate, and the Summary of Rights to Purchase Preferred Shares. (Incorporated by reference to Current Report on Form 8-K for Prima Energy Corporation dated May 23, 2001.)
10.1	Prima Energy Corporation Employee Stock Ownership Plan (Incorporated by reference to Annual Report on Form 10-K for Prima Energy Corporation for the year ended June 30, 1989.)
10.2	Prima Energy Corporation 1993 Stock Incentive Plan. (Incorporated by reference to Annual Report on Form 10-K for Prima Energy Corporation for the year ended December 31, 1993.)
10.3	

	Agreement of Lease between Denver-Stellar Associates LP, Landlord and Prima Energy Corporation, Tenant, effective December 1, 2001. (Incorporated by reference to Annual Report on Form 10-K for Prima Energy Corporation for the year ended December 31, 2000.)
10.4	Prima Energy Corporation Non-Employee Directors Stock Option Plan. (Incorporated by reference to Quarterly Report on Form 10-Q for Prima Energy Corporation for quarter ended March 31, 2002.)
10.5	Prima Energy Corporation 2001 Stock Incentive Plan. (Incorporated by reference to Quarterly Report on Form 10-Q for Prima Energy Corporation for the quarter ended March 31, 2002.)
14.1	Prima Energy Corporation Code of Ethics for Senior Financial Officers
21.1	Subsidiaries of the Registrant
23.1	Independent Auditors Consent
23.2	Independent Reservoir Engineers and Geologists Consent
31.1	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended
31.2	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a) /15d-14(a) of the Securities Exchange Act of 1934, as amended
32.1	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 USC Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002