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

FORM 10-K/A

(Amendment No. 1)

[X] Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended **December 31, 2003**
Commission file number **1-9735**

BERRY PETROLEUM COMPANY

(Exact name of registrant as specified in its charter)

DELAWARE	**77-0079387**
(State of incorporation or organization)	(I.R.S. Employer Identification Number)

5201 Truxtun Avenue, Suite 300
Bakersfield, California 93309
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code: **(661) 616-3900**

(Former name, former address and former fiscal year, if changed since last report)

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

Title of each class	Name of each exchange on which registered
Class A Common Stock, $.01 par value (including associated stock purchase rights)	**New York Stock Exchange**

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

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

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

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

As of June 30, 2003, the aggregate market value of the voting stock held by non-affiliates was $285,032,394. As of February 9, 2004, the registrant had 20,915,746 shares of Class A Common Stock outstanding. The registrant also had 898,892 shares of Class B Stock outstanding on February 9, 2004, all of which is held by an affiliate of the registrant.

DOCUMENTS INCORPORATED BY REFERENCE

Part III is incorporated by reference from the registrant's definitive Proxy Statement for its Annual Meeting of Shareholders to be filed, pursuant to Regulation 14A, no later than 120 days after the close of the registrant's fiscal year.

BERRY PETROLEUM COMPANY
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Explanatory Note

This Amendment No. 1 on Form 10-K/A amends in their entirety Items 6, 7, 8, 9(a) and 15 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, which was filed with the Securities and Exchange Commission on March 10, 2004. The purpose of this Amendment is to restate the Company's financial information to account for the Company's stock option plan using variable plan accounting and is more fully described in Note 14 to the financial statements included in Item 8 of this 10-K/A. All information contained in this Amendment is as of the original filing date of the Form 10-K for the year ended December 31, 2003 and does not reflect any subsequent information or events other than the restatement of financial information referred to above. Forward looking statements have not been updated for events or operations subsequent to March 10, 2004.

PART I
Items 1 and 2. Business and Properties

Company Website

The Company has a website located at http://www.bry.com. The website can be used to access recent news releases and Securities and Exchange Commission filings, crude oil price postings, the Company's Annual Report, Proxy Statement, Board committee charters, the code of ethics for senior financial officers and other items of interest.

General

Berry Petroleum Company, (Berry or Company), is an independent energy company engaged in the production, development, acquisition, exploitation and exploration of crude oil and natural gas. While the Company was incorporated in Delaware in 1985 and has been a publicly traded company since 1987, it can trace its roots in California oil production back to 1909. Currently, Berry's principal reserves and producing properties are located in the San Joaquin Valley, Los Angeles and Ventura basins in California and the Uinta Basin in northeastern Utah. The Company's corporate headquarters are located in Bakersfield, California. The Company also opened an office in Denver, Colorado in 2003 to pursue opportunities in the Rocky Mountain region. Management believes that these facilities are adequate for its current operations and anticipated growth. Information contained in this report on Form 10-K reflects the business of the Company during the year ended December 31, 2003.

The Company's mission is to increase shareholder returns, primarily through maximizing the value and cash flow of the Company's assets. To achieve this, Berry's corporate strategy is to, at a minimum, increase its net proved reserves annually, grow production annually and, in the process, increase both net income and cash flow in total and per share. To increase proved reserves and production, the Company will compete to acquire oil and gas properties with principally proved reserves and exploitation potential or sizeable acreage positions that the Company believes can ultimately contain substantial reserves which can be developed at reasonable costs. Additionally, the Company will continue to focus on the further development of its properties through developmental drilling, well completions, remedial work and by application of enhanced oil recovery (EOR) methods, as applicable. In conjunction with the goals of maximizing profitability and the exploitation and development of its substantial heavy crude oil base, the Company owns three cogeneration facilities which are intended to provide an efficient and secure long-term supply of steam which is necessary for the economic production of heavy oil. Berry views these assets as a key part of its long-term success. Berry believes that its primary strengths are its ability to maintain a cost-efficient operation, its flexibility in acquiring attractive producing properties which have significant exploitation and enhancement potential, its strong financial position and its experienced management team and staff. While the Company continues to seek investment opportunities in California, the Company has identified the Rocky Mountain region as a primary area of interest for growth. The Company believes that it can be successful in growing its reserve base and production in a profitable manner by investing in certain assets in the region. Additionally, it provides substantial opportunity for the Company to diversify its existing predominantly heavy crude oil base into light oil and natural gas. Strategically, the Company desires to increase its natural gas reserves and production as the Company consumes approximately 37,000 MMBtu daily as fuel for steam generation which is utilized in its California heavy oil operations. During the year, the Company opened an office in Denver and completed the purchase of the Brundage Canyon properties in the Uinta Basin in northeastern Utah. This acquisition and its ongoing development and operations are assisting Berry in achieving its strategies in the near term. The Company has an unsecured credit facility with a current borrowing base of $200 million (at year-end 2003, $150 million is available) which may be utilized in adding reserves and production through acquisitions.

Proved Reserves

As of December 31, 2003, the Company's estimated proved reserves were 110 million barrels of oil equivalent, (BOE), of which 91% are heavy crude oil, 6% light crude oil and 3% natural gas. A significant portion of these proved reserves are owned in fee. Geographically, 91% of the Company's reserves are located in California and 9% in the Rocky Mountain region. Production in 2003 was 6 million BOE, up 15% from 2002 production of 5.3 million BOE. For the five years 1999 through 2003, the Company's average annual reserve replacement rate was 163% and the acquisition, finding and development cost was $4.13 per BOE. Based on average daily fourth quarter production for each year, the Company's reserves-to-production ratio was 16.2 years at year-end 2003, reduced from 18.3 years at year-end 2002.

Acquisitions

The Company actively pursued its growth strategy, completing two acquisitions during the year. In August 2003, the Company completed the acquisition of the Brundage Canyon properties, in the Uinta Basin of Utah, for approximately $45 million. Brundage Canyon is Berry's first acquisition of a Company operated core asset outside of California, and is consistent with the Company's goal of building a strong asset portfolio in the Rocky Mountain region. This acquisition was financed utilizing the Company's revolving credit facility. At year-end, proved reserves for this property were approximately 9.2 million BOE or 8% of total reserves. In addition, the Company added to its California assets through the purchase of certain properties in the Poso Creek field in March, 2003 for $2.6 million. This acquisition added approximately 2.5 million BOE of proved reserves.

Operations

Berry operates all of its principal oil producing properties. In California, the Midway-Sunset and Placerita fields contain predominantly heavy crude oil which requires heat, supplied in the form of steam, injected into the oil producing formations to reduce the oil viscosity which allows the oil to flow to the well-bore for production. Berry utilizes cyclic steam and steam flood recovery methods in the Midway-Sunset and Placerita fields and primary recovery methods at its Montalvo field. Berry is able to produce its heavy oil at its Montalvo field without steam since the majority of the producing reservoir is at a depth in excess of 11,000 feet and thus the reservoir temperature is high enough to produce the oil without the assistance of additional heat from steam. In Utah, the Brundage Canyon field consists of light gravity crude and associated natural gas produced from a depth of approximately 6,000 feet. Company-wide field operations include the initial recovery of the crude oil and its transport through treating facilities into storage tanks. After the treating process is completed, which includes removal of water and solids by mechanical, thermal and chemical processes, the crude oil is metered through lease automatic custody transfer units or gauged before sale and subsequently transferred into crude oil pipelines owned by other companies or transported via truck. Crude oil produced from the Brundage Canyon field is transported by truck, while its gas production, net of field usage, is transported by feeder pipelines to two main shipper pipelines.

Revenues

Total revenues for 2003 increased by $50 million or 38% over 2002. Total revenues and the percentage of revenues by source for the prior three years are as follows:

	2003	2002	2001
Total revenues (in millions)	$ 181	$ 131	$ 138
Sales of oil and gas	75%	78%	72%
Sales of electricity	24%	21%	26%
Other	1%	1%	2%

Crude Oil and Natural Gas Marketing

The global and California crude oil markets continue to remain strong. The Organization of Petroleum Exporting Countries (OPEC) has successfully managed crude oil prices despite petroleum product demand weakness due to worldwide economic slowdowns and political instability during 2001 and 2002. Product prices began to rise in 2002 and continued to exhibit an overall-strengthening trend during 2003. The NYMEX settlement price for West Texas Intermediate (WTI), the U.S. benchmark crude oil, averaged $30.99 for 2003 compared to $26.15 for 2002 and $25.95 in 2001. The range for the year 2003 was a low of $25.24 and a high of $37.83. The average posted price for the Company's 13º API heavy crude oil was $25.27 for 2003 compared to $20.67 for 2002 and $18.70 for 2001. The range of posted prices for the Company's heavy crude oil in 2003 included a low of $18.81 and a high of $32.44.

While crude oil price differentials between WTI and California's heavy crude widened during 2001, the trend reversed in 2002 and continued to stay below $6 per barrel during 2003. The crude price differential between WTI and California's heavy crude oil has averaged $5.73, $5.48 and $7.25 for 2003, 2002 and 2001, respectively. A price-sensitive royalty burdens one of the Company's California properties which produces approximately 4,000 barrels per day. This royalty is 75% of the amount of the heavy oil posted price above a base price which was $14.59 in 2003. This base price escalates at 2% annually, thus the threshold price is $14.88 per barrel in 2004.

Berry markets its crude oil production to competing buyers including independent marketers but primarily to major oil refining companies. Because of the Company's ability to deliver significant volumes of crude oil over a multi-year period, the Company was able to secure a three-year sales agreement, beginning in April 2000, with a major California refiner whereby the Company sold in excess of 80% of its California production under a negotiated pricing mechanism. This contract was renegotiated during 2002 and extended through 2005. Over 90% of the Company's current California production is subject to this new contract. Pricing in the new agreement is based upon the higher of the average of the local field posted prices plus a fixed premium, or WTI minus a fixed differential. Both methods are calculated using a monthly determination. In addition to providing a premium above field postings, the agreement effectively eliminates the Company's exposure to the risk of widening WTI to California heavy crude price differentials and allows the Company to effectively hedge its production based on WTI pricing. The Brundage Canyon crude oil, which is approximately 40 degree API gravity, is priced at WTI less a fixed differential.

Berry markets produced natural gas from Utah, Wyoming and California. In October 2003, the Company began marketing produced gas from the Brundage Canyon field. The majority of the natural gas from Brundage Canyon is sold in the Salt Lake City market at a Questar monthly index related price with an adjustment for transportation. Brundage Canyon volume in excess of Berry's firm pipeline transportation volume is sold at the field at a Questar daily spot related price. The Company owns a non-operated working interest in the South Joe Creek field in the Powder River Basin in Wyoming. Berry started marketing its working interest share of production in-kind from South Joe Creek in December 2002, at Glenrock, Wyoming at monthly Colorado Interstate Gas (CIG) index related prices. Additionally, produced gas from the West Montalvo field near Oxnard, CA is exchanged and valued at a daily SoCal Border spot related price.

For 2003, SoCal Border first-of-month indices averaged \$5.05 per MMBtu and the Rockies CIG indices averaged \$4.19 per MMBtu. The average monthly index price for the Questar price point was \$4.07 per MMBtu in the fourth quarter of 2003. The closing price for the NYMEX prompt month natural gas contract averaged \$5.84, \$3.37 and \$4.05 for years 2003, 2002 and 2001 respectively. The weighted average price the Company received per Mcf during these years was \$5.03, \$2.31 and \$4.06 respectively.

The Company has physical access to interstate gas pipelines, such as the Kern River Pipeline and the Questar Pipeline, as well as California intrastate systems owned by Southern California Gas Company and Pacific Gas & Electric (PG&E), to move gas to or from market. To avoid negative financial impacts to the Company should California pipeline capacity become constrained, the Company entered into a long-term gas transportation contract with Kern River Gas Transmission Company for 12,000 MMBtu/D. This is a ten year contract which began in May 2003. The Company also holds two firm transportation contracts on the Questar Pipeline system in Utah.

From time to time, the Company enters into crude oil and natural gas hedge contracts, the terms of which depend on various factors, including Management's view of future crude oil prices and the Company's future financial commitments. This price protection program is designed to moderate the effects of a severe price downturn while allowing Berry to participate in the upside after a maximum per barrel payment. Currently, the hedges are in the form of swaps or options; however, the Company is considering using a variety of hedge instruments for use in the future. The Company has utilized bracketed zero-cost collars as they meet the Company's objectives of retaining significant upside while being adequately protected on a significant downside price movement. These price protection activities resulted in a net cost or (benefit)/BOE to the Company of \$1.96 in 2003, \$.72 in 2002 and (\$.16) in 2001.

The following table summarizes the hedge position of the Company as of February 9, 2004:

Crude Oil and Natural Gas Hedges
(Based on NYMEX Pricing)

Term	Barrels Per Day	Floor Sell Put	Floor Buy Put	Ceiling Sell Call	Ceiling Buy Call
Crude Oil Hedges					
01/01/2004 – 03/31/2004	2,500	$ 18.25	$ 22.10	$ 25.40	$ 30.10
01/01/2004 – 03/31/2004	2,500	$ 18.25	$ 22.10	$ 25.45	$ 30.10
04/01/2004 – 12/31/2004	1,000	$ 19.00	$ 22.00	$ 25.50	$ 29.40
04/01/2004 – 12/31/2004	1,000	$ 19.50	$ 23.00	$ 26.00	$ 29.75
04/01/2004 – 12/31/2004	1,000	$ 19.50	$ 23.00	$ 26.00	$ 29.50
04/01/2004 – 12/31/2004	1,000	$ 19.50	$ 23.00	$ 26.25	$ 29.85
01/01/2004 – 04/30/2004	1,000	$ -	$ 25.00	$ 25.00	$ -
01/01/2004 – 12/31/2004	1,500	$ -	$ 29.25	$ 29.25	$ -
01/01/2004 – 12/31/2004	1,500	$ -	$ 29.00	$ 29.00	$ -
Natural Gas Hedges	MMBtu Per Day				
01/01/2004 – 06/30/2006	2,500	$ 4.85	$ -	$ -	$ 4.85
01/01/2004 – 06/30/2006	2,500	$ 4.85	$ -	$ -	$ 4.85

Payments to our counterparties are triggered when NYMEX monthly average prices are between the Ceiling Sell Call and Buy Call prices. Conversely, payments from our counterparties are received when the NYMEX monthly average prices are between the Floor Sell Put and Buy Put prices. Management regularly monitors the crude oil markets and the Company's financial commitments to determine if, when, and at what level some form of crude oil hedging or other price protection is appropriate.

Steaming Operations

Cogeneration Steam Supply

As of December 31, 2003, approximately 86% of the Company's proved reserves, or 94 million barrels, consisted of heavy crude oil produced from depths shallower than 2,000 feet. The Company, in pursuing its goal of being a cost-efficient heavy oil producer, has remained focused on minimizing its steam cost. One of the main methods of keeping steam costs low is through the ownership and efficient operation of cogeneration facilities. Two of these cogeneration facilities, a 38 megawatt (MW) and an 18 MW facility are located in the Company's South Midway-Sunset field. The Company also owns a 42 MW rated cogeneration facility located at the Company's Placerita field. Steam generation from these facilities, with a total steam capacity of approximately 38,000 barrels of steam per day (BSPD), is more efficient than conventional steam generation as both steam and electricity are concurrently produced from a common fuel stream. The Company purchases approximately 2,000 BSPD under contract on favorable terms from a non-Company owned cogeneration facility

Conventional Steam Generation

In addition to these cogeneration plants, the Company owns sixteen conventional boilers. The number which are operated at any one time is dependent on the quantity needed to meet peak steam demands. The total rated capacity of the conventional boilers is also approximately 38,000 BSPD.

Blending Sources for an Advantage

The Company believes it has a distinct advantage over other operators by the ownership of these varied steam generation facilities and sources, allowing for maximum control over the steam supply, location, and to some extent the aggregated cost. The Company's steam supply and flexibility are crucial for the maximization of oil production, cost control and ultimate reserve recovery.

High natural gas prices have persisted throughout 2003. The cost of natural gas purchased per MMBtu averaged $4.88, $3.13, and $5.76 for 2003, 2002 and 2001, respectively. Many of the Company's conventional steam generators were run in 2003 to achieve the Company's goal of increasing heavy oil production to record levels.

The Company believes that it may become necessary to add additional steam capacity for its future development projects at South Midway-Sunset and Placerita to allow for full development of its properties. While the Company vigorously pursued the possibility of constructing additional cogeneration facilities in 2001 and tested the market in 2002, the regulatory environment and operating and financial conditions for new cogeneration facilities in California remain uncertain. The Company regularly reviews its most economical source for obtaining additional steam to achieve its growth objectives.

Electricity Generation

The total annual average electrical generation of the Company's three cogeneration facilities is approximately 93 MW, of which the Company consumes approximately 8 MW for use in its operations. The three facilities can also supply approximately 38,000 BSPD. Each facility is centrally located on an oil producing property such that the steam generated by the facility is capable of being delivered to the wells that require steam for the enhanced oil recovery process. The Company's investment in its cogeneration facilities have been for the express purpose of lowering the steam costs in its heavy oil operations and securing operating control of the respective steam generation. Expenses of operating the cogeneration plants are analyzed monthly on a Company-wide basis. Any profits from cogeneration operations are considered profits from electricity generation. If expenses exceed electricity revenues, the excess expenses are recorded as oil and gas operating costs.

Electricity Sales Contracts

Historically, the Company has sold electricity produced by its cogeneration facilities to Southern California Edison Company (Edison) and PG&E under long-term contracts. These contracts are referred to as Standard Offer (SO) contracts under which the Company is paid an energy payment that reflects the utility's avoided short-term variable cost to produce electricity (SRAC) plus a capacity payment that reflects a recovery of capital expenditures that would otherwise have been made by the utility. The capacity payments are either fixed throughout the term of the agreement or can be adjusted from time to time by the California Public Utilities Commission (CPUC). The SRAC energy price is determined by a formula that reflects the utility's marginal fuel cost and a conversion efficiency that represents a hypothetical utility resource to generate electricity in the absence of the cogenerator. Natural gas is now the marginal fuel for California Investor Owned Utilities (IOUs) so this formula provides a hedge against the Company's cost of gas to produce electricity and steam in its cogeneration facilities.

As the California energy crisis worsened in 2000, neither utility paid the Company for electricity delivered under the contracts from late 2000 through March 2001. PG&E filed for bankruptcy on April 6, 2001 and Edison operated on the brink of bankruptcy for an extended period. The Company was forced to shut down its cogeneration facilities and to terminate its SO contracts with PG&E in order to seek a creditworthy buyer for its electricity. Berry sold electricity from its Cogen 18 and Cogen 38 facilities to a creditworthy, non-utility buyer from June 2001 through December 2002. In June 2001, the CPUC approved an agreement under which Berry resumed operation of its Placerita cogeneration facilities, Edison agreed to amend the SRAC payment terms and resume payments to Berry under its original SO contracts, and Edison agreed to pay all past due amounts owed Berry since November 2000. The original SO contract for Placerita Unit 1 continues in effect through March 2009. The modified SRAC pricing terms reflect a fixed energy price of 5.37 cents/kilowatt per hour (KWh) until June 2006, at which time the energy price reverts to the SRAC pricing methodology then approved by the CPUC. Edison continued to purchase electricity under the SO contract for Placerita Unit 2 until its scheduled expiration in May 2002. From June 2002 through January 2003, the Company sold electricity from that facility to a creditworthy, non-utility buyer. On

August 22, 2002, the CPUC ordered the California IOUs to offer SO contracts to certain cogeneration facilities with expired SO contracts (Qualifying Facilities or QFs) for a maximum term of one year. The Company met these requirements and entered into new SO contracts with Edison for its Placerita Unit 2 and with PG&E for its Cogen 38 and Cogen 18 facilities effective January 2003. These three new SO contracts resulted in improved electrical pricing, which in turn contributed to lower operating costs for the Company's crude oil production operations during 2003. All three SO contracts terminated on December 31, 2003, as originally ordered by the CPUC.

On December 18, 2003, the CPUC ordered the California IOUs to continue to offer SO contracts to certain QFs with expired SO contracts, such as Berry, for a one year term beginning January 1, 2004. In the same decision, the CPUC also directed its staff to initiate a comprehensive review and revision of the SRAC pricing methodology. Edison has appealed the legality of the December 18, 2003 CPUC decision that ordered the additional one-year extension of SO contracts. They also contend the term of the agreement could be less than one year. The Company disputes Edison's claims and opposes Edison's appeal of the decision. The Company executed a one year extension of its SO contract with Edison for the Placerita Unit 2 facility, that is subject to early termination if Edison is successful in their appeal. The Company also executed one year extensions of its SO contracts with PG&E.

On January 22, 2004, the CPUC issued a decision that establishes the rules under which the California IOUs will produce or procure energy for their customers for at least the next 5-10 years. Among other things, this decision ordered the California IOUs to offer SO contracts to certain QFs whose SO contracts will terminate prior to December 31, 2005, such as Berry, for a term of 5 years. The SRAC price paid under these SO contracts is subject to the same prospective adjustments that were required in the prior CPUC decision that ordered the one-year extension. The Company is carefully reviewing the options available in the recent CPUC order.

Facility and Contract Summary

Location and Facility	Type of Contract	Purchaser	Contract Expiration	Approximate Megawatts Available for Sale	Approximate Megawatts Consumed in Operations	Approximate Barrels of Steam Per Day
Placerita						
Placerita Unit 1	SO2	Edison	Mar-09	20	-	6,600
Placerita Unit 2	SO1	Edison	Dec-04	16	4	6,700
South Midway-Sunset						
Cogen 18	SO1	PG&E	Dec-04	12	4	6,600
Cogen 38	SO1	PG&E	Dec-04	37	-	18,000

<u>Environmental and Other Regulations</u>

Berry Petroleum Company is committed to responsible management of the environment, health and safety, as these areas relate to the Company's operations. The Company strives to achieve the long-term goal of sustainable development within the framework of sound environmental, health and safety practices and standards. Berry makes environmental, health and safety protection an integral part of all business activities, from the acquisition and management of its resources through the decommissioning and reclamation of its wells and facilities.

The oil and gas production business in which Berry participates is complex. All facets of the Company's operations are affected by a myriad of federal, state, regional and local laws, rules and regulations. Berry is further affected by changes in such laws and by constantly changing administrative regulations. Furthermore, government agencies may impose substantial liabilities if the Company fails to comply with such regulations or for any contamination resulting from the Company's operations.

Therefore, Berry has programs in place to identify and manage known risks, to train employees in the proper performance of their duties and to incorporate viable new technologies into its operations. The costs incurred to ensure compliance with environmental, health and safety laws and other regulations are inextricably connected to normal operating expenses such that the Company is unable to separate the expenses related to these matters.

Currently, California environmental laws and regulations are being revised to lower emissions from stationary sources.

Although these requirements do have a substantial impact upon the energy industry, generally these requirements do not appear to affect the Company any differently, or to any greater or lesser extent, than other companies in California. Berry believes that compliance with environmental laws and regulations will not have a material adverse effect on the Company's operations or financial condition. There can be no assurances, however, that changes in, or additions to, laws and regulations regarding the protection of the environment will not have such an impact in the future.

Berry maintains insurance coverage that it believes is customary in the industry although it is not fully insured against all environmental or other risks. The Company is not aware of any environmental claims existing as of December 31, 2003 that would have a material impact upon the Company's financial position, results of operations, or liquidity.

Competition

The oil and gas industry is highly competitive. As an independent producer, the Company does not own any refining or retail outlets and, therefore, it has little control over the price it receives for its crude oil. As such, higher costs, fees and taxes assessed at the producer level cannot necessarily be passed on to the Company's customers. In acquisition activities, significant competition exists as integrated and independent companies and individual producers and operators are active bidders for desirable oil and gas properties. Although many of these competitors have greater financial and other resources than the Company, Management believes that Berry is in a position to compete effectively due to its low cost structure, transaction flexibility, strong financial position, experience and determination.

Employees

On December 31, 2003, the Company had 129 full-time employees, up from 113 full-time employees on December 31, 2002.

Oil and Gas Properties

Development

Unless otherwise noted, gross acreage, net wells, fourth quarter production, and year-end reserves are used in the property descriptions below.

California

Midway-Sunset - Berry owns and operates working interests in 38 properties consisting of 4,559 acres located in the Midway-Sunset field. The Company estimates these properties account for approximately 67% of the Company's proved oil and gas reserves and approximately 64% of its current daily production. Of these properties, 18 are owned in fee. The wells produce from an average depth of approximately 1,200 feet, and rely on thermal EOR methods, primarily cyclic steaming.

During 2003, the primary focus at Midway-Sunset was on the Formax properties. Of the 83 wells drilled in the Midway-Sunset field in 2003, 13 were horizontal wells, and 31 were on the Formax properties. The objectives of using horizontal drilling are to improve ultimate recovery of original oil-in-place, reduce the development and operating costs of the properties and to accelerate production. In 2004, the Company plans to drill an additional 42 wells in the Midway-Sunset field, including 2 horizontals.

Placerita – The Company's assets in the Placerita field consist of six leases and three fee properties totaling approximately 1,030 acres. The average depth of these wells is 1,800 feet and the properties rely extensively on thermal recovery methods, primarily steam flooding. The property accounts for approximately 17% of proved reserves and 19% of current daily production.

During 2003, the Company drilled eleven development wells at Placerita in continuation of a major development campaign at the north end of the field. Included in the Company's 2004 development plan is the drilling of three new wells to begin the redevelopment of the Castruccio property the Company acquired several years ago.

Montalvo – Berry owns a 100% working interest in six leases totaling 8,563 acres in the Ventura Basin comprising the entire Montalvo field. The State of California is the lessor for two of the six leases. The Company estimates current proved reserves from Montalvo account for approximately 5% of Berry's proved oil and gas reserves and approximately 4% of Berry's current daily production. The wells produce from an average depth of approximately 11,500 feet. No new wells were drilled in 2003, however several wells were remediated and returned to production. There are no plans at this time to drill any new wells in 2004, however two idle wells are scheduled to be returned to production and one major workover will be completed.

McVan – In March 2003, the Company purchased a 100% working interest in the McVan property located in the Poso Creek field. The property consists of 560 acres with a total of 71 wells. Year-end 2003 proved reserves comprise 2% of Berry's proved oil and gas reserves while production is minimal. Plans for 2004 include drilling one well, working over 10 wells and reinitiating steam injection on the property.

Rockies and Mid-Continent

Brundage Canyon, Utah - On August 28, 2003, Berry closed the acquisition of and assumed operations of the Brundage Canyon field, Duchesne County, Utah. The Brundage Canyon leasehold consists of federal, tribal and private leases totaling 45,380 gross acres. The Company estimates that the Brundage Canyon properties account for approximately 8% of proved oil and gas reserves and approximately 12% of current daily production. There are 110 wells in the Brundage Canyon field, producing oil and associated natural gas with an average well depth of 6,000 feet.

Berry initiated a twenty-six well, two rig drilling program in early September, 2003, immediately following the closing of the acquisition, and twenty-two of the new wells were producing by year-end. The field is currently being developed on eighty-acre spacing with substantial undeveloped acreage. The Company's objectives for 2004 include the drilling of 44 additional wells and the recompletion of twenty existing wells.

South Joe Creek, Wyoming - The Company holds a 15.83% non-operated working interest in the South Joe Creek coalbed methane gas field which represents interests in federal, state and private leases totaling 5,266 acres in the northeastern portion of the Powder River Basin in Wyoming. The property has 84 wells (13 net). At year-end, the net production rate was 1,200 Mcf per day, or approximately 1% of daily production and net reserves were less than 1%. We anticipate the drilling of 15 wells (2.4 net) in 2004.

Mickelson Creek, Wyoming – In June 2003, the Company purchased three federal leases located in the Mickelson Creek field in Sublette County, Wyoming. There are currently five wells on the 2,800 acre property. While production and reserves are minimal at this time, the Company plans to drill two wells and recomplete two wells in 2004.

Kansas and Illinois Coalbed Methane (CBM) Projects – In mid-2002, the Company began to build a significant acreage position in both Eastern Kansas (208,000 acres) and Central Illinois (54,000 acres) to develop natural gas production and reserves from known coalbeds. The Company drilled a five-spot production pilot in each state in late 2002. In 2003, the Company determined both these pilots were non-commercial. As such, the Company has no reserves in either state as of December 31, 2003. The Company sold its interest in 43,000 acres in Kansas in mid-2003 while retaining an overriding royalty interest. The Company's objectives in 2004 include the continued evaluation of CBM activities in Illinois and further delineation of our CBM acreage in Kansas.

The following is a summary of the Company's capital expenditures incurred during 2003 and 2002 and budgeted capital expenditures for 2004.

CAPITAL EXPENDITURES SUMMARY
(in thousands)

	2004 (Budgeted) (1)	2003	2002
CALIFORNIA			
Midway-Sunset Field			
New wells	$ 6,885	$ 10,710	$ 10,224
Remedials/workovers	2,045	1,718	1,981
Facilities - oil & gas	2,385	3,136	1,340
Facilities - cogeneration (2)	150	231	898
General	1,682	187	-
	13,147	15,982	14,443
Placerita			
New wells	322	6,509	5,278
Remedials/workovers	1,233	154	174
Facilities - oil & gas	1,590	916	2,480
Facilities - cogeneration (2)	150	370	4,382
	3,295	7,949	12,314
Montalvo			
Remedials/workovers	1,180	928	909
Facilities	425	94	179
	1,605	1,022	1,088
McVan			
New Wells	150	-	-
Remedials/workovers	650	2	-
Facilities	540	666	-
	1,340	668	-
Total California	19,387	25,621	27,845
ROCKIES AND MID-CONTINENT			
Brundage Canyon			
New Wells	26,203	14,298	-
Remedials/workovers	2,332	234	-
Facilities	1,930	146	-
	30,465	14,678	-
Mickelson Creek			
New Wells	1,500	-	-
Remedials/workovers	300	-	-
Facilities	175	-	-
	1,975	-	-
Kansas and Illinois (CBM)(3)			
New wells	300	392	1,185
Facilities	-	346	47
Remedials/workovers	-	3	-
	300	741	1,232
South Joe Creek (3) (4)			
New wells	332	8	355
Facilities	-	5	216
	332	13	571
Total Rocky Mountain and Mid-Continent	33,072	15,432	1,803
Other	450	502	984
Totals	$ 52,909	$ 41,555	$ 30,632

(1) *Budgeted capital expenditures may be adjusted for numerous reasons including, but not limited to, oil, natural gas and electricity price levels. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.*

(2) *Cogeneration facility costs are excluded in the Company's calculation of its finding and development costs.*

(3) *Represents coalbed methane (CBM) development activity.*

(4) *Represents Berry's net share, or 15.83%, of the total expenditures.*

Exploration

The Company considered its pilot wells in both Kansas and Illinois to be exploratory in nature as there was no proven production near those areas; however, these were relatively inexpensive shallow wells. In recent years, the Company has concentrated on growth through development of existing assets and strategic acquisitions. The Company is pursuing an acquisition strategy which may include some exploratory drilling in the future.

Enhanced Oil Recovery Tax Credits

The Revenue Reconciliation Act of 1990 included a tax credit for certain costs associated with extracting high-cost, capital-intensive marginal oil or gas and which utilizes at least one of nine designated "enhanced" or tertiary recovery methods. Cyclic steam and steam flood recovery methods for heavy oil, which Berry utilizes extensively, are qualifying EOR methods. In 1996, California conformed to the federal law, thus, on a combined basis, the Company is able to achieve credits approximating 12% of its qualifying costs. The credit is earned only for qualified EOR projects by investing in one of three types of expenditures: 1) drilling development wells, 2) adding facilities that are integrally related to qualified EOR production, or 3) utilizing a tertiary injectant, such as steam, to produce oil. The credit may be utilized to reduce the Company's tax liability down to, but not below, its alternative minimum tax liability. This credit is significant in reducing the Company's income tax liabilities and effective tax rate.

Oil and Gas Reserves

The Company continued to engage DeGolyer and MacNaughton (D&M) to appraise the extent and value of its proved oil and gas reserves and the future net revenues to be derived from properties of the Company for the year ended December 31, 2003. D&M is an independent oil and gas consulting firm located in Dallas, Texas. In preparing their reports, D&M reviewed and examined geologic, economic, engineering and other data considered applicable to properly determine the reserves of the Company. They also examined the reasonableness of certain economic assumptions regarding forecasted operating and development costs and recovery rates in light of the economic environment on December 31, 2003. For the Company's operated properties, such reserve estimates are filed annually with the U.S. Department of Energy. See the Supplemental Information About Oil & Gas Producing Activities (Unaudited) for the Company's oil and gas reserve disclosures.

Production

The following table sets forth certain information regarding production for the years ended December 31, as indicated:

	2003	2002	2001
Net annual production:(1)			
Oil (Mbbls)	5,827	5,123	4,996
Gas (Mmcf)	1,277	769	288
Total equivalent barrels(2)	6,040	5,251	5,044
Average sales price:			
Oil (per Bbl) before hedging	$24.41	$20.27	$19.53
Oil (per Bbl) after hedging	22.37	19.54	19.70
Gas (per mcf) before hedging	4.40	2.22	5.09
Gas (per mcf) after hedging	4.43	2.22	5.09
Per BOE before hedging	24.48	20.11	19.63
Per BOE after hedging	22.52	19.39	19.79
Average operating cost – oil and gas production (per BOE)(3)	10.05	8.49	7.99

Mbbls – Thousands of Barrels
Mmcf – Million Cubic Feet
BOE – Barrels of Oil Equivalent

(1) *Net production represents that owned by Berry and produced to its interest, less royalty and other similar interests.*

(2) *Equivalent oil and gas information is at a ratio of 6 thousand cubic feet (mcf) of natural gas to 1 barrel (Bbl) of oil. A barrel of oil (Bbl) is equivalent to 42 U.S. gallons.*

(3) *Includes monthly expenses in excess of monthly revenues from cogeneration operations (per BOE) of $2.08, $1.72 and $1.31 for 2003, 2002 and 2001, respectively. See Note 2 to the financial statements.*

Acreage and Wells

As of December 31, 2003, the Company's properties accounted for the following developed and undeveloped acres:

	Developed Acres		Undeveloped Acres		Total	
	Gross	Net	Gross	Net	Gross	Net
California	7,786	7,786	7,404	7,404	15,190	15,190
Utah	9,520	9,360	35,860	34,140	45,380	43,500
Wyoming	3,800	750	4,266	2,250	8,066	3,000
Illinois	-	-	54,306	54,306	54,306	54,306
Kansas	-	-	163,993	163,993	163,993	163,993
Other	80	17	-	-	80	17
	21,186	17,913	265,829	262,093	287,015	280,006

Gross acres represent acres in which Berry has a working interest; net acres represent Berry's aggregate working interests in the gross acres.

Berry currently has 2,757 gross oil wells (2,752 net) and 84 gross gas wells (13 net). Gross wells represent the total number of wells in which Berry has a working interest. Net wells represent the number of gross wells multiplied by the percentages of the working interests owned by Berry. One or more completions in the same bore hole are counted as one well. Any well in which one of the multiple completions is an oil completion is classified as an oil well.

Drilling Activity

The following table sets forth certain information regarding Berry's drilling activities for the periods indicated:

	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells drilled:						
Productive	-	-	-	-	-	-
Dry(1)	-	-	11	11	-	-
Development wells drilled: (2)						
Productive	121	119	81	76	103	47
Dry(1)	1	1	-	-	1	-
Total wells drilled:						
Productive	121	119	81	76	103	47
Dry(1)	1	1	11	11	1	-

(1) *A dry well is a well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well. The 11 wells drilled in 2002 were determined to be dry holes in 2003.*

(2) *Wells drilled include 2 wells gross, .3 wells net for 2003, 6 wells gross, 1 well net for 2002 and 67 wells gross, 11 wells net for 2001 at South Joe Creek where the Company holds a 15.83% working interest.*

As of December 31, 2003, one well was being drilled on the Brundage Canyon property.

Title and Insurance

To the best of the Company's knowledge, there are no defects in the title to any of its principal properties including related facilities. Notwithstanding the absence of a recent title opinion or title insurance policy on all of its properties, the Company believes it has satisfactory title to its properties, subject to such exceptions as the Company believes are customary and usual in the oil and gas industry and which the Company believes will not materially impair its ability to recover the proved oil and gas reserves or to obtain the resulting economic benefits.

The oil and gas business can be hazardous, involving unforeseen circumstances such as blowouts or environmental damage. Although it is not insured against all risks, the Company maintains a comprehensive insurance program to address the hazards inherent in operating its oil and gas business.

Item 3. Legal Proceedings

While the Company is, from time to time, a party to certain lawsuits in the ordinary course of business, the Company does not believe any of such existing lawsuits will have a material adverse effect on the Company's operations, financial condition, or liquidity.

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

None.

Executive Officers

Listed below are the names, ages (as of December 31, 2003) and positions of the executive officers of Berry and their business experience during at least the past five years. All officers of the Company are appointed in May of each year at an organizational meeting of the Board of Directors. There are no family relationships between any of the executive officers and members of the Board of Directors.

JERRY V. HOFFMAN, 54, Chairman of the Board, President and Chief Executive Officer. Mr. Hoffman has been President and Chief Executive Officer since May 1994 and President and Chief Operating Officer from March 1992 until May 1994. Mr. Hoffman was added to the Board of Directors in March 1992 and named Chairman in March 1997. Mr. Hoffman held the Senior Vice President and Chief Financial Officer positions from January 1988 until March 1992 and was Chief Financial Officer from December 1985 until January 1988.

RALPH J. GOEHRING, 47, Senior Vice President and Chief Financial Officer. Mr. Goehring has been Senior Vice President since April 1997, Chief Financial Officer since March 1992 and was Manager of Taxation from September 1987 until March 1992. Mr. Goehring is also an Assistant Secretary for the Company.

GEORGE T. CRAWFORD, 43, has been Vice President of Production since December 2000 and was Manager of Production, from January 1999 to December 2000. Mr. Crawford, a petroleum engineer, was previously the Production Engineering Supervisor for ARCO Western Energy, a subsidiary of Atlantic Richfield Corp. (ARCO). Mr. Crawford was employed by ARCO from 1989 to 1998 in numerous engineering and operational assignments including Production Engineering Supervisor, Planning and Evaluation Consultant and Operations Superintendent.

MICHAEL DUGINSKI, 37, has been Vice President of Corporate Development since February 2002. Mr. Duginski, a mechanical engineer, was previously with Texaco, Inc. from 1988 to 2002 where his positions included Director of New Business Development, Production Manager and Gas and Power Operations Manager. Mr. Duginski is also an Assistant Secretary for the Company.

LOGAN MAGRUDER, 47, has been Vice President of Rocky Mountain and Mid-Continent Region since August 2003 and was a consultant for the Company from February until August 2003. Mr. Magruder was previously Vice President of U.S. Operations for Calpine Natural Gas Company during 2001. Prior to Calpine, Mr. Magruder was employed by Barrett Resources as Vice President of Engineering and Operations from 1996 to 2001.

BRIAN L. REHKOPF, 56, has been Vice President of Engineering since March 2000 and was Manager of Engineering from September 1997 to March 2000. Mr. Rehkopf, a registered petroleum engineer, joined the Company’s engineering department in June 1997 and was previously a Vice President and Asset Manager with ARCO Western Energy since 1992 and an Operations Engineering Supervisor with ARCO from 1988 to 1992. Mr. Rehkopf is also an Assistant Secretary for the Company.

DONALD A. DALE, 57, has been Controller since December 1985.

KENNETH A. OLSON, 48, has been Corporate Secretary since December 1985 and Treasurer since August 1988.

PART II

Item 5. Market for the Registrant’s Common Equity and Related Shareholder Matters

Shares of Class A Common Stock (Common Stock) and Class B Stock, referred to collectively as the "Capital Stock," are each entitled to one vote and 95% of one vote, respectively. Each share of Class B Stock is entitled to a $1.00 per share preference in the event of liquidation or dissolution. Further, each share of Class B Stock is convertible into one share of Common Stock at the option of the holder.

In November 1999, the Company adopted a Shareholder Rights Agreement and declared a dividend distribution of one such Right for each outstanding share of Capital Stock on December 8, 1999. Each share of Capital Stock issued after December 8, 1999 includes one Right. The Rights expire on December 8, 2009. See Note 7 of Notes to the Financial Statements.

Berry's Class A Common Stock is listed on the New York Stock Exchange under the symbol (NYSE:BRY). The Class B Stock is not publicly traded. The market data and dividends for 2003 and 2002 are shown below:

	2003			2002		
	Price Range		Dividends	Price Range		Dividends
	High	Low	Per Share	High	Low	Per Share
First Quarter	$ 17.01	$ 14.65	$ 0.10	$ 16.90	$ 13.25	$ 0.10
Second Quarter	18.38	14.40	0.15	17.58	15.45	0.10
Third Quarter	19.17	16.96	0.11	18.25	14.52	0.10
Fourth Quarter	20.95	17.90	0.11	17.50	15.60	0.10

The closing price per share of Berry's Common Stock, as reported on the New York Stock Exchange Composite Transaction Reporting System for February 9, 2004, December 31, 2003 and December 31, 2002 was $19.07, $20.25 and $17.05, respectively.

The number of holders of record of the Company's Common Stock was 705 as of February 9, 2004. There was one Class B Shareholder of record as of February 9, 2004.

In August 2001, the Board of Directors authorized the Company to repurchase $20 million of Common Stock in the open market. As of December 31, 2001, the Company had repurchased 308,075 shares for approximately $5.1 million. All shares repurchased were retired. No additional shares were repurchased in 2002 or 2003.

The Company paid a special dividend of $.04 per share on May 2, 2003 and increased its regular quarterly dividend by 10%, from $.10 to $.11 per share beginning with the June 2003 dividend.

Since Berry Petroleum Company's formation in 1985 through December 31, 2003, the Company has paid dividends on its Common Stock for 57 consecutive quarters and previous to that for eight consecutive semi-annual periods. The Company intends to continue the payment of dividends, although future dividend payments will depend upon the Company's level of earnings, operating cash flow, capital commitments, financial covenants and other relevant factors.

As of December 31, 2003, dividends declared on 4,000,894 shares of certain Common Stock are restricted, whereby 37.5% of the dividends declared on these shares are paid by the Company to the surviving member of a group of individuals, the B group, for as long as this remaining member shall live.

Item 6. Selected Financial Data

The following table sets forth certain financial information with respect to the Company and is qualified in its entirety by reference to the historical financial statements and notes thereto of the Company included in Item 8, "Financial Statements and Supplementary Data." The statement of operations and balance sheet data included in this table for each of the five years in the period ended December 31, 2003 were derived from the audited financial statements and the accompanying notes to those financial statements (in thousands, except per share, per BOE and % data). See Note 14 of Notes to financial statements regarding the restatement of the Company's financial information to account for the Company's stock option plan using variable plan accounting:

	2003	2002	2001	2000	1999
	(Restated)	(Restated)	(Restated)	(Restated)	(Restated)
Statement of Operations Data :					
Sales of oil and gas	$ 135,848	$ 102,026	$ 100,146	$ 118,801	$ 66,615
Sales of electricity	44,200	27,691	35,133	51,420	33,011
Operating costs – oil and gas production	60,705	44,604	40,281	44,837	27,829
Operating costs – electricity generation	44,200	27,360	34,722	49,221	27,210
General and administrative expenses (G&A)	12,868	9,215	8,718	6,782	7,325
Depreciation, depletion & amortization (DD&A)	20,514	16,452	16,520	14,030	12,294
Net income [(1)]	32,363	29,210	20,985	37,766	17,372
Basic net income per share [(1)]	1.49	1.34	0.96	1.71	0.79
Diluted net income per share [(1)]	1.47	1.33	0.95	1.70	0.79
Weighted average number of shares outstanding (basic)	21,772	21,741	21,973	22,029	22,010
Weighted average number of shares outstanding (diluted)	22,020	21,939	22,110	22,240	22,049
Balance Sheet Data :					
Working capital	$ (3,540)	$ (2,892)	$ 6,314	$ (963)	$ 8,693
Total assets	340,377	259,325	238,779	238,572	208,251
Long-term debt	50,000	15,000	25,000	25,000	52,000
Shareholders' equity [(2)]	197,338	172,774	153,590	145,220	116,599
Cash dividends per share	0.47	0.40	0.40	0.40	0.40
Operating Data :					
Cash flow from operations	64,825	57,895	35,433	65,934	24,809
Capital expenditures (excluding acquisitions)	41,555	30,632	14,895	25,253	9,122
Property/facility acquisitions	48,579	5,880	2,273	3,182	33,605
Oil and gas producing operations (per BOE):					
Average sales price before hedging	$ 24.48	$ 20.11	$ 19.63	$ 23.01	$ 14.15
Average sales price after hedging	22.52	19.39	19.79	21.72	13.07
Average operating costs[(3)]	10.05	8.49	7.99	8.20	5.47
G&A	2.13	1.75	1.73	1.24	1.44
DD&A	3.40	3.13	3.28	2.57	2.42
Production (BOE)	6,040	5,251	5,044	5,467	5,090
Production (MWh)	767	748	483	764	728
Proved Reserves Information:					
Total BOE	109,920	101,719	102,855	107,361	112,541
Standardized measure [(4)]	$ 528,220	$ 449,857	$ 278,453	$ 501,694	$ 494,952
Present value (PV10) of estimated future net cash flow before income taxes	683,124	599,826	358,653	719,882	712,856
Year-end average BOE price for PV10 purposes	25.89	24.91	14.13	21.13	19.37
Other:					
Return on average shareholders' equity	17.50%	17.90%	14.00%	28.80%	15.50%
Return on average total assets	10.80%	11.70%	8.80%	16.90%	9.10%
Total debt/total debt plus equity	20.2%	8.0%	14.0%	14.7%	30.8%
Year-end stock price	$ 20.25	$ 17.05	$ 15.70	$ 13.38	$ 15.13
Year-end market capitalization	$ 441,516	$ 370,865	$ 341,192	$ 294,699	$ 332,920

[(1)]Net income, basic earnings per share, and diluted earnings per share decreased by $(1,969), $(.09) and $(.09) in 2003, decreased by $(814), $(.04) and $(.04) in 2002, decreased by $(953), $(.04) and $(.04) in 2001, increased by $583, $.02, $.03 in 2000 and decreased by $(634), $(.03) and $(.03) in 1999, respectively, as a result of the restatement, see Note 14 under Item 8 "Financial Statements and Supplementary Data".

[(2)]Shareholders' Equity has been restated by $4 and $386 in 2000 and 1999, respectively, see Note 14 under Item 8 "Financial Statements and Supplementary Data".

[(3)] Including monthly expenses in excess of monthly revenues from cogeneration operations of $2.08, $1.72, $1.31, $.53, and $0 for the years 2003, 2002, 2001, 2000, and 1999, respectively.

[(4)]See Supplemental Information About Oil & Gas Producing Activities.

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

The following discussion provides information on the results of operations for each of the three years ended December 31, 2003, 2002 and 2001 and the financial condition, liquidity and capital resources as of December 31, 2003 and 2002. The financial statements and the notes thereto contain detailed information that should be referred to in conjunction with this discussion.

The profitability of the Company's operations in any particular accounting period will be directly related to the average realized prices of oil, gas and electricity sold, the type and volume of oil and gas produced and electricity generated and the results of acquisition, development, exploitation and exploration activities. The average realized prices for natural gas and electricity will fluctuate from one period to another due to regional market conditions and other factors, while oil prices will be predominantly influenced by world supply and demand. The aggregate amount of oil and gas produced may fluctuate based on the success of development and exploitation of oil and gas reserves pursuant to current reservoir management. The cost of natural gas used in the Company's steaming operations and electrical generation, production rates, labor, maintenance expenses and production taxes are expected to be the principal influences on operating costs. Accordingly, the results of operations of the Company may fluctuate from period to period based on the foregoing principal factors, among others.

Restatement of Financial Information

As further discussed in Note 14 to the financial statements, the Company has restated its financial statements to account for the Company's stock option plan using variable plan accounting, insofar as the Company had permitted option holders to exercise options by surrendering underlying unexercised options in payment of the exercise price of the options and related taxes. While the Company had accounted for options issued under the plan as fixed awards with compensation expense recorded for certain option exercises, it has been determined that variable plan accounting is required under generally accepted accounting principles in the United States. The use of variable plan accounting requires a charge to compensation expense, commencing at the grant date, in an amount by which the market price of the Company's stock covered by the grant exceeds the option price. This accounting continues and subsequent changes in the market price of the Company's stock from the date of grant to the date of exercise or forfeiture result in a change in the measure of compensation cost for the award being recognized but not resulting in an accumulated adjustment below zero. These adjustments are reflected in the financial statements with the cumulative adjustment to Shareholders' Equity as of January 1, 2001 resulting in an increase in Capital in Excess of Par Value of $.4 million, increase in Deferred Stock Based Compensation of $.1 million and decrease in Retained Earnings of $.3 million. As a result of the restatement, Capital in Excess of Par Value was increased by $6.7 million, $3.2 million, and $1.8 million as of December 31, 2003, 2002, and 2001, respectively. Deferred Stock-Based Compensation increased by $1.0 million, $.3 million and $.1 million as of December 31, 2003, 2002, and 2001, respectively. Retained Earnings decreased by $4.1 million, $2.1 million and $1.3 million as of December 31, 2003, 2002, and 2001, respectively. The adjustments decreased the Company's net income by $2.0 million or $0.09 per share (diluted) in 2003, $.8 million, or $0.04 per share (diluted) in 2002, and $1.0 million, or $0.04 per share (diluted) in 2001. The Company has also restated its results of operations for each of the quarters in 2003 and 2002 as discussed under "Selected Quarterly Financial Data" on page 50. Amounts in the ensuing discussion have been adjusted for these restatements where applicable.

Results of Operations

In 2003, the Company achieved a record year for revenues and its second highest net income. The Company earned $32.4 million, or $1.47 per share (diluted), in 2003 on revenues of $181 million, up 11% from $29.2 million, or $1.33 per share (diluted), on revenues of $131 million in 2002, and up from $21 million, or $.95 per share (diluted), on revenues of $138 million earned in 2001.

The following table presents certain operating data for the years ended December 31:

	2003 (Restated)	2002 (Restated)	2001 (Restated)
Oil and Gas			
Net production – BOE/D	16,549	14,387	13,820
Per BOE:			
Average sales price before hedging	$ 24.48	$ 20.11	$ 19.63
Average sales price after hedging	22.52	19.39	19.79
Operating costs(1)	9.41	7.94	7.50
Production taxes	0.64	0.55	0.49
Total operating costs	$ 10.05	$ 8.49	$ 7.99
DD&A	$ 3.40	$ 3.13	$ 3.28
G&A	2.13	1.75	1.73
Interest expense	0.23	0.20	0.74
Electricity			
Electric power produced - MWh/D	2,100	2,050	1,325
Electric power sold – MWh/D	1,925	1,848	1,245
Average sales price/MWh before hedging	$ 62.91	$ 40.06	$ 79.14
Average sales price/MWh after hedging	$ 61.95	$ 39.64	$ 79.14
Fuel gas cost/MMBtu	$ 4.88	$ 3.13	$ 5.76

(1) Including monthly expenses in excess of monthly revenues from cogeneration operations of $2.08, $1.72 and $1.31 in 2003, 2002 and 2001 respectively.

BOE/D = Barrels of oil equivalent per day
MWh/D = Megawatt hours per day
MMBtu = Million British Thermal Units

In August 2003, the Company completed the acquisition of the Brundage Canyon properties, for approximately $45 million. The Company believes that this property presents a significant opportunity for growth due to the considerable amount of underexploited acreage. At year-end, proved reserves for this property were approximately 9.2 million BOE, or 8% of total reserves. Subsequent to the acquisition, the Company pursued a drilling program which included the drilling of 26 wells, 22 of which were producing at year end. As a result, current production has increased to nearly 3,000 barrels per day for Brundage Canyon.

The Company's oil and gas production reached record levels in 2003 due primarily to the success of the Company's development activities on its California properties, the acquisition of leases in the Brundage Canyon field in Utah in August 2003 and the drilling activities on these Utah properties in the last four months of 2003. Oil and gas production (BOE/D) for 2003 was 16,549, up 15% and 20%, respectively, from 14,387 in 2002 and 13,820 in 2001.

The Company primarily is at risk to reductions in operating income as a result of declines in crude oil and electricity prices and increases in natural gas prices. To assist in mitigating these risks, the Company periodically enters into various types of commodity hedges. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk".

The 2003 average sales price per BOE of the Company's oil and gas, net of hedging, was $22.52, up 16% and 14.7% from $19.39 and $19.79 received in 2002 and 2001, respectively. Approximately 96% of the Company's sales volumes in 2003 were crude oil, with 86% of the crude oil being heavy oil produced in California which is sold under a long-term contract based on the higher of WTI minus a fixed differential or the Company's average posted price plus a premium. The Brundage Canyon crude oil is priced at WTI less a fixed differential. During 2003, WTI prices per barrel reached a high of $37.83, a low of $25.24 and averaged $30.99 for the year compared to an average of $26.15 and $25.95 in 2002 and 2001, respectively.

The Company produced 2,100 MWh/D of electricity in 2003, comparable to 2,050 MWh/D in 2002, but up 58% from 1,325 MWh/D produced in 2001. The Company's cogeneration facilities were shut in for a number of months in 2001 due to non-payment by the utilities that were contractually obligated to purchase the Company's electricity.

During 2003, the Company received an average sales price for its electricity per MWh of $62.91 compared to $40.06 in 2002 and $79.14 in 2001. During 2003, electricity prices were, relative to the cost of natural gas to generate electricity, improved from 2002. In January 2003, three Standard Offer contract terms were reinstated on certain generating capacity of which the output had been sold by the Company on the open market during all of 2002 and the majority of 2001. This volume represented approximately 76% of the Company's electricity sales output. Under the terms of the Standard Offer contracts, the price received for the electricity is based on the cost of natural gas. The Company consumes approximately 37,000 MMBtu of natural gas per day for use in generating steam and of this total, approximately 72% is consumed in the Company's cogeneration operations. By maintaining a correlation between electricity and natural gas prices, the Company is able to better control its cost of producing steam.

Three of the Standard Offer 1 contracts expired on December 31, 2003. However, by order of the California Public Utilities Commission (CPUC), in December 2003 the respective utilities offered extensions of the Standard Offer 1 contracts for up to one year. The CPUC issued a decision in January 2004 that establishes rules under which the California utilities are required to offer Standard Offer 1 contracts to certain qualifying facilities (QF), such as Berry, for a term of five years. In January 2004, the Company accepted one-year extensions of these contracts and is evaluating its options beyond the revised termination dates.

Operating costs from oil and gas operations were $60.7 million in 2003, up 36% and 51% from $44.6 million and $40.3 million in 2002 and 2001, respectively. On a per barrel basis, operating costs cost were $10.05 in 2003 compared to $8.49 and $7.99 in 2002 and 2001, respectively. Steam costs were higher in 2003 as the cost for natural gas per MMBtu increased to $4.88 from $3.13 in 2002. Although natural gas prices in 2001 of $5.76 were higher than the 2003 prices, the Company had shut-in its cogeneration operations for a portion of 2001 due to the California electricity crisis resulting in reduced steam injection volumes and lower total operating costs in 2001. The Company also injected an average of 63,300 BSPD in 2003, up 5% from 60,060 BSPD in 2002 and 33,574 BSPD in 2001. This increase in injected steam volumes also contributed to higher operating costs in 2003. The Company anticipates operating costs to average between $9.50 and $10.50 per BOE in 2004.

DD&A in 2003 was $20.5 million, or $3.40 per BOE, up from $16.5 million, or $3.13 per BOE, in 2002 and $16.5 million, or $3.28 per BOE, in 2001. DD&A in 2003 was higher due to the acquisition of the Brundage Canyon properties in Utah and the cumulative effect of development activities in recent years. The Company anticipates its total DD&A charges for 2004 will approximate $28 million or range from $3.75 to $4.00 per BOE.

G&A expenses in 2003 were $12.9 million, or $2.13 per BOE, up 40% from $9.2 million, or $1.75 per BOE in 2002 and up 48% from $8.7 million, or $1.73 per BOE in 2001. Contributing to the increase in 2003 was higher compensation expenses, the expansion into the Rocky Mountain region, and a higher level of acquisition activity. Included in these amounts is stock option compensation of $3.9 million, $1.3 million, and $1.6 million in 2003, 2002, and 2001, respectively, which are primarily non-cash charges resulting from mark-to-market adjustments under the variable method of accounting. For 2004, the Company anticipates that its G&A expenses will approximate $10.5 million or range from $1.35 to $1.45 per BOE.

Interest expense in 2003 was $1.4 million, or $.23 per BOE, up from $1.0 million, or $.20 per BOE, in 2002 but down from $3.7 million, or $.74 per BOE, in 2001. The Company's borrowings at year-end 2003 were $50 million, up from $15 million in 2002 due to the acquisition of its Brundage Canyon properties in August 2003.

In 2002, the Company recorded income of $3.6 million, which represented the recovery of a portion of the $6.6 million of the receivables from electricity sales that were written off in 2001 due to non-payment by utilities contractually obligated to purchase the Company's electricity.

The Company experienced an effective tax rate of 12% in 2003, down from the 20% and 18% reported in 2002 and 2001, respectively. The low effective tax rate is primarily a result of significant EOR tax credits earned by the Company's continued investment in the development of its thermal EOR projects, both through capital expenditures and continued steam injection. This is the sixth consecutive year that the Company has achieved an effective tax rate below 30% versus the combined federal and state statutory rate of 40%. The Company believes it will continue to earn significant EOR tax credits. and have an effective tax rate in the 20% to 30% range in 2004, based on WTI prices averaging between $26.50 and $35.50.

During 2002 and early 2003, the Company leased a total of approximately 208,000 acres in Kansas and 54,000 acres in Illinois to explore for economic concentrations of coalbed methane gas at a total lease cost of approximately $6 million. A five-well pilot was drilled in the Wabaunsee County portion of the Kansas acreage in the fourth quarter of 2002. Initial water production was less than expected with no resulting gas pressure buildup and the gas content of the coals was later determined to be significantly lower than anticipated. The Company concluded that this pilot will not produce commercial quantities of natural gas and, therefore, wrote off the cost to drill these wells and the associated acreage in 2003 for a pre-tax charge to operations of $2.6 million.

In August 2003, the Company completed the sale of approximately 43,000 leased acres in Jackson County, Kansas for approximately $1.7 million, while retaining an overriding royalty interest in the property. The Company recovered its cost in the property.

The Company also drilled a second five-well pilot in Jasper County, Illinois in the fourth quarter of 2002. The wells were subsequently re-fractured in the third quarter of 2003 in an attempt to more efficiently dewater the coal seam and reduce the reservoir pressure to increase eventual gas production. Although reservoir pressure decreased over time, it was determined near year-end 2003 that gas volumes are not likely to be sufficient to realize commercial production; therefore, the costs to drill these wells and an impairment of the acreage was recorded in the fourth quarter of 2003, which resulted in a pre-tax charge of $1.7 million. The Company's objectives in 2004 include the continued evaluation of CBM activities in Illinois and further delineation of our CBM acreage in Kansas.

Financial Condition, Liquidity and Capital Resources

Working capital as of December 31, 2003 was negative ($3.5) million, up from a negative ($2.9) million at December 31, 2002 and a positive $6.3 million at December 31, 2001. Net cash provided by operating activities increased to $64.8 million, up 12% from $57.9 million in 2002 and up 83% from $35.4 million in 2001. The Company's net increase in borrowings on its credit line was $35 million in 2003. Cash was used to fund $48.6 million in property acquisitions, for capital expenditures of $41.5 million and to pay dividends of $10.2 million.

Total capital expenditures in 2003, excluding acquisitions, were $41.5 million and included the drilling of 94 new wells and completing 30 workovers on its California properties and the drilling of 27 new wells and completion of one workover on its Brundage Canyon properties in Utah.

Excluding any future acquisitions in 2004, the Company plans to spend approximately $50 million on capital projects including $17 million to drill 44 new wells and perform 63 workovers in California and $33 million to drill 51 new wells and perform 22 workovers in the Rocky Mountain and Mid-Continent regions. With this increased development and a full year of production from Brundage Canyon, the Company anticipates that production will average between 20,000 and 21,000 BOE per day in 2004, up over 20% from an average 16,549 BOE per day in 2003.

The Company successfully completed a new $200 million unsecured three-year credit facility in July 2003. The facility replaced the previous $150 million unsecured facility which was due to mature in January 2004. The new facility recognizes the Company's strong financial position and should provide significant low-cost capital for the Company to meet its growth objectives. In August 2003, the Company drew upon this facility to finance the $45 million purchase of the Brundage Canyon, Utah assets. As of December 31, 2003, the Company had $150 million available under the facility.

At year-end, the Company had no subsidiaries, no special purpose entities and no off-balance sheet debt. The Company did not enter into any significant related party transactions in 2003.

Contractual Obligations

The Company's contractual obligations as of December 31, 2003 are as follows (in thousands):

Contractual Obligations	2004	2005	2006	2007	2008	Thereafter	Total
Long-term debt	$ -	$ -	$ 50,000	$ -	$ -	$ -	$ 50,000
Operating lease obligations	528	562	487	107	107	90	1,881
Firm natural gas transportation contract	3,066	3,066	3,066	3,066	3,066	13,280	28,610
Total	$ 3,594	$ 3,628	$ 53,553	$ 3,173	$ 3,173	$ 13,370	$ 80,491

Critical Accounting Policies

The preparation of financial statements in conformity with generally accepted accounting principles requires Management to make estimates and assumptions for the reporting period and as of the financial statement date. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent liabilities and the reported amounts of revenues and expenses. Actual results could differ from those amounts.

A critical accounting policy is one that is important to the portrayal of the Company's financial condition and results, and requires Management to make difficult subjective and/or complex judgments. Critical accounting policies cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. The Company believes the following accounting policies are critical policies; accounting for oil and gas reserves, environmental liabilities, income taxes and asset retirement obligations.

Oil and gas reserves include proved reserves that represent estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The oil and gas reserves are based on estimates prepared by independent engineering consultants and are used to calculate DD&A and determine if any potential impairment exists related to the recorded value of the Company's oil and gas properties.

The Company reviews, on a quarterly basis, its estimates of costs of the cleanup of various sites including sites in which governmental agencies have designated the Company as a potentially responsible party. When it is probable that obligations have been incurred and where a minimum cost or a reasonable estimate of the cost of remediation can be determined, the applicable amount is accrued. Actual costs can differ from estimates due to changes in laws and regulations, discovery and analysis of site conditions and changes in technology.

The Company makes certain estimates in determining its provision for income taxes. These estimates in determining taxable income, among other things, may include various tax planning strategies, the timing of deductions and the utilization of tax attributes.

Management is required to make judgments based on historical experience and future expectations on the future abandonment cost of its oil and gas properties and equipment. The Company reviews its estimate of the future obligation quarterly and accrues the estimated obligation monthly based on SFAS No. 143, “Accounting for Asset Retirement Obligations”.

Recent Accounting Developments

In the fourth quarter of 2002, the Company adopted the supplemental disclosure requirements of SFAS No. 148, “Accounting for Stock-Based Compensation – Transition and Disclosure”, which amended SFAS No. 123, “Accounting for Stock-Based Compensation.” The Company records compensation related to employee stock options using the variable method accounting prescribed under APB Opinion No. 25, “Accounting for Stock Issued to Employees.” SFAS No. 148 encourages companies to voluntarily elect to record the compensation based on market value either prospectively, as defined in SFAS No. 123, or retroactively or in a modified prospective method. The Company uses the Black-Scholes model to calculate and disclose the market value of its options granted.

In November 2002 the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others ("FIN 45")." This Interpretation addresses the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees. In addition, the Interpretation clarifies the requirements related to the recognition of a liability by a guarantor at the inception of a guarantee for the obligations that the guarantor has undertaken in issuing the guarantee. The Company adopted the disclosure requirements of FIN 45 for the fiscal year ended December 31, 2002, and the recognition provisions on January 1, 2003. Adoption of this Interpretation did not have a material impact on the Company's Financial Statements.

In June 2002 the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities," which addresses accounting for restructuring and similar costs. SFAS No. 146 supersedes previous accounting guidance, principally EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (Including Certain Costs Incurred in a Restructuring)." The Company has adopted, effective January 1, 2003, the provisions of SFAS No. 146 for restructuring activities initiated after December 31, 2002. SFAS No. 146 requires that the liability for costs associated with an exit or disposal activity be recognized when the liability is incurred. Under EITF No. 94-3, a liability for an exit cost was recognized at the date of commitment to an exit plan. SFAS No. 146 also establishes that the liability should initially be measured and recorded at fair value. Accordingly, SFAS No. 146 may affect the timing of recognizing future restructuring costs as well as the amounts recognized. SFAS No. 146 did not have a material impact on the Company's financial statements.

In April 2003 the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS No. 149 amends and clarifies financial reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under SFAS No. 133. SFAS No. 149 clarifies under what circumstances a contract with an initial net investment meets the characteristic of a derivative, clarifies when a derivative contains a financing component, amends the definition of an underlying to conform it to language used in FIN 45, and amends certain other existing pronouncements. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003, and should be applied prospectively, with the exception of certain SFAS No. 133 implementation issues that were effective for all fiscal quarters prior to June 15, 2003. Any such implementation issues should continue to be applied in accordance with their respective effective dates. The adoption of SFAS No. 149 did not have a material impact on the Company's financial statements.

During January 2003, the Financial Accounting Standards Board issued Interpretation No. 46, “Consolidation of Variable Interest Entities” (“FIN 46”), which requires the consolidation of certain entities that are determined to be variable interest entities (“VIE’s”). An entity is considered to be a VIE when either (i) the entity lacks sufficient equity to carry on its principal operations, (ii) the equity owners of the entity cannot make decisions about the entity’s activities or (iii) the entity’s equity neither absorbs losses or benefits from gains. The Company has reviewed its financial arrangements and has not identified any material VIE’s that should be consolidated by the Company in accordance with FIN 46.

Impact of Inflation

The impact of inflation on the Company has not been significant in recent years because of the relatively low rates of inflation experienced in the United States.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company enters into various financial contracts to hedge its exposure to commodity price risk associated with its crude oil production, electricity production and net natural gas volumes purchased for its steaming operations. These contracts related to crude oil and natural gas have historically been in the form of zero-cost collars and swaps, however, the Company is considering a variety of hedge instruments going forward. The Company generally attempts to hedge between 25% and 50% of its anticipated crude oil production and up to 30% of its anticipated net natural gas purchased each year. All of these hedges have historically been deemed to be cash flow hedges with the mark-to-market valuations of the collars provided by external sources, based on prices that are actually quoted.

Based on NYMEX futures prices at December 31, 2003, (WTI $30.64; Henry Hub (HH) $5.21) the Company would expect to make pre-tax future cash payments over the remaining term of its crude oil and natural gas hedges in place as follows:

	12/31/03 NYMEX Futures	Impact of percent change in futures prices on earnings (in thousands) -20%	-10%	+ 10%	+ 20%
Average WTI Price	$ 30.64	$ 24.51	$27.57	$ 33.70	$ 36.77
Crude Oil gain/(loss)	(8,400)	4,730	(1,710)	(12,420)	(16,160)
Average HH Price	5.21	4.17	4.69	5.73	6.25
Natural Gas gain/(loss)	410	(3,720)	(1,650)	2,470	4,530

The Company sells 100% of its electricity production, net of electricity used in its oil and gas operations, under SO contracts to major utilities. Three of the four SO contracts representing approximately 77% of the Company’s electricity for sale originally expired on December 31, 2003. However, as ordered by CPUC, the utilities offered and the Company accepted one-year extensions on these contracts in January 2004 and is evaluating its options beyond the revised termination dates. Among other things, the CPUC issued a decision in January 2004 that establishes rules whereby the California utilities are required to offer Standard Offer contracts to certain qualified facilities, such as Berry, for a term of 5 years. However, the sales price under this contract may not be linked to natural gas prices. The Company sells the remaining 20 MWh to a utility at $53.70 per MWh plus capacity through a long-term sales contract.

The Company attempts to minimize credit exposure to counter parties through monitoring procedures and diversification.

The Company's exposure to changes in interest rates results primarily from long-term debt. Total debt outstanding at December 31, 2003 and 2002 was $50 million and $15 million, respectively. Interest on amounts borrowed is charged at LIBOR plus 1.25% to 2.0%. Based on year-end 2003 borrowings, a 1% change in interest rates would not have a material impact on the Company's financial statements.

Forward Looking Statements

"*Safe harbor under the Private Securities Litigation Reform Act of 1995:" With the exception of historical information, the matters discussed in this Form 10-K are forward-looking statements that involve risks and uncertainties. Although the Company believes that its expectations are based on reasonable assumptions, it can give no assurance that its goals will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include, but are not limited to, the timing and extent of changes in commodity prices for oil, gas and electricity, a limited marketplace for electricity sales within California, counterparty risk, competition, environmental and weather risks, litigation uncertainties, drilling, development and operating risks, uncertainties about the estimates of reserves, the availability of drilling rigs and other support services, legislative and/or judicial decisions and other government regulations.*

Item 8. Financial Statements and Supplementary Data

BERRY PETROLEUM COMPANY
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Financial statement schedules have been omitted since they are either not required, are not applicable, or the required information is shown in the financial statements and related notes.

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
Berry Petroleum Company

In our opinion, the accompanying balance sheets and the related statements of income, comprehensive income, shareholders' equity and cash flows present fairly, in all material respects, the financial position of Berry Petroleum Company at December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 14 to the financial statements, the Company has restated its financial statements for the years ended December 31, 2003, 2002 and 2001.

/s/ PricewaterhouseCoopers LLP

Los Angeles, California
February 20, 2004, except for Note 14, as to which the date is August 6, 2004

BERRY PETROLEUM COMPANY
Balance Sheets
December 31, 2003 and 2002
(In Thousands, Except Share Information)

	2003 (Restated)	2002 (Restated)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10,658	$ 9,866
Short-term investments available for sale	663	660
Accounts receivable	23,506	15,582
Deferred income taxes	6,410	2,030
Prepaid expenses and other	2,049	1,753
Total current assets	43,286	29,891
Oil and gas properties (successful efforts basis), buildings and equipment, net	295,151	228,475
Other assets	1,940	959
	$ 340,377	$ 259,325
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 32,490	$ 19,189
Accrued liabilities	4,214	6,470
Income taxes payable	4,412	3,001
Fair value of derivatives	5,710	4,123
Total current liabilities	46,826	32,783
Long-term liabilities:		
Deferred income taxes	38,559	34,013
Long-term debt	50,000	15,000
Abandonment obligation	7,311	4,596
Fair value of derivatives	343	159
	96,213	53,768
Commitments and contingencies (Notes 10 and 11)		
Shareholders' equity:		
Preferred stock, $.01 par value, 2,000,000 shares authorized; no shares outstanding	-	-
Capital stock, $.01 par value:		
Class A Common Stock, 50,000,000 shares authorized; 20,904,372 shares issued and outstanding (20,852,695 in 2002)	209	209
Class B Stock, 1,500,000 shares authorized; 898,892 shares issued and outstanding (liquidation preference of $899)	9	9
Capital in excess of par value	56,475	52,214
Deferred stock option compensation	(1,108)	(346)
Accumulated other comprehensive loss	(3,632)	(2,569)
Retained earnings	145,385	123,257
Total shareholders' equity	197,338	172,774
	$ 340,377	$ 259,325

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

BERRY PETROLEUM COMPANY
Statements of Income
Years ended December 31, 2003, 2002 and 2001
(In Thousands, Except Per Share Data)

	2003 (Restated)	2002 (Restated)	2001 (Restated)
Revenues:			
Sales of oil and gas	$ 135,848	$ 102,026	$ 100,146
Sales of electricity	44,200	27,691	35,133
Interest and dividend income	236	536	2,150
Other income	580	1,116	328
	180,864	131,369	137,757
Expenses:			
Operating costs – oil and gas production	60,705	44,604	40,281
Operating costs – electricity generation	44,200	27,360	34,722
Depreciation, depletion & amortization	20,514	16,452	16,520
General and administrative	12,868	9,215	8,718
Interest	1,414	1,042	3,719
Dry hole, abandonment and impairment	4,195	-	-
(Recovery) write-off of electricity receivable	-	(3,631)	6,645
Loss on termination of derivative contracts	-	-	1,458
	143,896	95,042	112,063
Income before income taxes	36,968	36,327	25,694
Provision for income taxes	4,605	7,117	4,709
Net income	$ 32,363	$ 29,210	$ 20,985
Basic net income per share	$ 1.49	$ 1.34	$ 0.96
Diluted net income per share	$ 1.47	$ 1.33	$ 0.95
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)	21,772	21,741	21,973
Effect of dilutive securities:			
Stock options	204	156	113
Other	44	42	24
Weighted average number of shares of capital stock used to calculate diluted net income per share	22,020	21,939	22,110

Statements of Comprehensive Income
Years Ended December 31, 2003, 2002 and 2001
(In Thousands)

	2003	2002	2001
Net income	$ 32,363	$ 29,210	$ 20,985
Unrealized gains (losses) on derivatives, net of income taxes	(3,632)	(2,569)	-
Reclassification of unrealized gains included in net income	2,569	-	(441)
Comprehensive income	$ 31,300	$ 26,641	$ 20,544

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

BERRY PETROLEUM COMPANY
Statements of Shareholders' Equity
Years Ended December 31, 2003, 2002 and 2001
(In Thousands, Except Per Share Data)

	Class A	Class B	Capital in Excess of Par Value (Restated)	Deferred Stock Based Compensation (Restated)	Retained Earnings (Restated)	Accumulated Other Comprehensive Income (Loss)	Shareholders' Equity (Restated)
Balances at January 1, 2001, as previously reported	$ 211	$ 9	$ 53,686	$ -	$ 90,877	$ 441	$ 145,224
Adjustments (Note 14)	-	-	410	(81)	(333)	-	(4)
Balances at January 1, 2001, as restated	211	9	54,096	(81)	90,544	441	145,220
Accrued compensation costs	-	-	1,567	-	-	-	1,567
Deferred director fees – stock compensation	-	-	156	-	-	-	156
Unearned stock based							-
compensation	-	-	20	(20)	-	-	
Common stock repurchases	(3)	-	(5,109)	-	-	-	(5,112)
Cash dividends declared - $.40 per share	-	-	-	-	(8,784)	-	(8,784)
Unrealized losses on derivatives	-	-	-	-	-	(441)	(441)
Net income	-	-	-	-	20,985	-	20,985
Balances at December 31, 2001	208	9	50,730	(101)	102,745	-	153,591
Accrued compensation costs	1	-	1,149	-	-	-	1,150
Deferred director fees – stock							-
compensation	-	-	190	-	-	-	190
Unearned stock based compensation	-	-	245	(245)	-	-	-
Retirement of warrants	-	-	(100)	-	-	-	(100)
Cash dividends declared -							-
$.40 per share	-	-	-	-	(8,698)	-	(8,698)
Unrealized losses on derivatives	-	-	-	-	-	(2,569)	(2,569)
Net income	-	-	-	-	29,210	-	29,210
Balances at December 31, 2002	209	9	52,214	(346)	123,257	(2,569)	172,774
Accrued compensation costs	-	-	3,319	-	-	-	3,319
Deferred director fees – stock							-
compensation	-	-	169	-	-	-	169
Unearned stock based compensation	-	-	773	(773)	-	-	-
Amortization of deferred stock option compensation	-	-	-	11	-	-	11
Cash dividends declared -							-
$.47 per share	-	-	-	-	(10,235)	-	(10,235)
Unrealized losses on derivatives	-	-	-	-	-	(1,063)	(1,063)
Net income	-	-	-	-	32,363	-	32,363
Balances at December 31, 2003	$ 209	$ 9	$ 56,475	$ (1,108)	$ 145,385	$ (3,632)	$ 197,338

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

BERRY PETROLEUM COMPANY
Statements of Cash Flows
Years Ended December 31, 2003, 2002 and 2001
(In Thousands)

	2003 (Restated)	2002 (Restated)	2001 (Restated)
Cash flows from operating activities:			
Net income	$ 32,363	$ 29,210	$ 20,985
Depreciation, depletion and amortization	20,514	16,452	16,520
Dry hole, abandonment and impairment	3,756	-	-
Deferred stock option compensation	2,872	1,093	1,407
Deferred income taxes	1,496	3,883	(203)
Other, net	400	(184)	(518)
Decrease (increase) in current assets other than cash, cash equivalents and short-term investments	(9,034)	1,469	10,623
Increase (decrease) in current liabilities other than notes payable	12,458	5,972	(13,381)
Net cash provided by operating activities	64,825	57,895	35,433
		-	
Cash flows from investing activities:			
Capital expenditures, excluding property acquisitions	(41,555)	(30,632)	(14,895)
Property acquisitions	(48,579)	(5,880)	(2,273)
Proceeds from sale of assets	1,890	-	-
Purchase of short-term investments	(3)	(660)	(1,183)
Maturities of short-term investments	-	594	1,171
Other, net	524	52	151
Net cash used in investing activities	(87,723)	(36,526)	(17,029)
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	40,000	5,000	45,000
Payment of long-term debt	(5,000)	(15,000)	(45,000)
Dividends paid	(10,235)	(8,698)	(8,784)
Share repurchase program	-	-	(5,112)
Other, net	(1,075)	(43)	(1)
Net cash provided by (used in) financing activities	23,690	(18,741)	(13,897)
Net increase in cash and cash equivalents	792	2,628	4,507
Cash and cash equivalents at beginning of year	9,866	7,238	2,731
Cash and cash equivalents at end of year	$ 10,658	$ 9,866	$ 7,238
Supplemental disclosures of cash flow information:			
Interest paid	$ 2,125	$ 1,321	$ 3,532
Income taxes paid	$ 2,510	$ 5,420	$ 5,635
Supplemental non-cash activity:			
Decrease in fair value of derivatives:			
Current (net of income taxes of $635 and $1,649)	$ 952	$ 2,474	$ -
Non-current (net of income taxes of $74 and $63)	111	95	-
Net decrease to accumulated other comprehensive income	$ 1,063	$ 2,569	$ -

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

1. General

The Company is an independent energy company engaged in the production, development, acquisition, exploitation and exploration of crude oil and natural gas. The Company has 91% of its oil and gas reserves in California and 9% in the Rocky Mountain Region. Approximately 87% of the Company's production is in California, most of which is heavy crude oil, which is principally sold to a refiner. The Company has invested in cogeneration facilities which provide steam required for the extraction of heavy oil and which generates electricity for sale. Production of light crude oil and natural gas in the Rocky Mountain region accounts for approximately 13% of the Company's production.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires Management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

2. Summary of Significant Accounting Policies

<u>Cash and cash equivalents</u>

The Company considers all highly liquid investments purchased with a remaining maturity of three months or less to be cash equivalents.

<u>Short-term investments</u>

All short-term investments are classified as available for sale. Short-term investments consist principally of United States treasury notes and corporate notes with remaining maturities of more than three months at date of acquisition and are carried at fair value. The Company utilizes specific identification in computing realized gains and losses on investments sold.

<u>Oil and gas properties, buildings and equipment</u>

The Company accounts for its oil and gas exploration and development costs using the successful efforts method. Under this method, costs to acquire and develop proved reserves and to drill and complete exploratory wells that find proved reserves are capitalized and depleted over the remaining life of the reserves using the units-of-production method. Exploratory dry hole costs and other exploratory costs, including geological and geophysical costs, are charged to expense when incurred. In certain cases, such as coalbed methane gas exploration plays, the drilling costs may be capitalized until it is known whether proved economic reserves have been discovered. At that point, if unsuccessful, the costs will be expensed as exploratory dry hole costs.

The FASB is currently evaluating 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 FASB is considering whether the provisions of SFAS No. 141 and SFAS No. 142 require registrants to classify costs associated with mineral rights, including both proved and unproved lease acquisition costs, as intangible assets in the balance sheet, apart from other oil and gas property costs, and provide specific footnote disclosures. At the present time, the Company continues to include these intangible assets in its oil and gas properties.

Depletion of oil and gas producing properties is computed using the units-of-production method. Depreciation of lease and well equipment, including cogeneration facilities and other steam generation equipment and facilities, is computed using the units-of-production method or on a straight-line basis over estimated useful lives ranging from 10 to 20 years. Buildings and equipment are recorded at cost. Depreciation is provided on a straight-line basis over estimated useful lives ranging from 5 to 30 years for buildings and improvements and 3 to 10 years for machinery and equipment. Prior to 2002, the estimated costs of plugging and abandoning wells and related facilities were accrued using the units-of-production method and were considered in determining DD&A expense. However, in 2002 the Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." Under this standard, the Company records the fair value of the future abandonment as capitalized abandonment costs in Oil and Gas Properties with an offsetting abandonment liability. The capitalized abandonment costs are amortized with other property costs using the units-of-production method. The Company increases the liability monthly by recording accretion expense using the Company's credit adjusted interest rate. Accretion expense is included in depreciation, depletion and amortization (DD&A) in the Company's financial statements.

2. Summary of Significant Accounting Policies (cont'd)

Assets are grouped at the field level and if it is determined that the book value of long-lived assets cannot be recovered by estimated future undiscounted cash flows, they are written down to fair value. When assets are sold, the applicable costs and accumulated depreciation and depletion are removed from the accounts and any gain or loss is included in income. Expenditures for maintenance and repairs are expensed as incurred.

Environmental Expenditures

The Company reviews, on a quarterly basis, its estimates of costs of the cleanup of various sites, including sites in which governmental agencies have designated the Company as a potentially responsible party. When it is probable that obligations have been incurred and where a minimum cost or a reasonable estimate of the cost of compliance or remediation can be determined, the applicable amount is accrued. For other potential liabilities, the timing of accruals coincides with the related ongoing site assessments. Any liabilities arising hereunder are not discounted.

Hedging

SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities,” as amended, requires that all derivative instruments subject to the requirements of the statement be measured at fair value and recognized as assets or liabilities in the balance sheet. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation is generally established at the inception of a derivative. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of SFAS No. 133, changes in fair value, to the extent effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time, or in the case of options based on the change in intrinsic value. Any change in fair value of a derivative resulting from ineffectiveness or an excluded component of the gain/loss, such as time value for option contracts, is recognized immediately as operating costs in the statement of operations. See Note 3 - Fair Value of Financial Instruments.

Cogeneration Operations

The Company operates cogeneration facilities to help minimize the cost of producing steam, which is a necessity in its thermal oil and gas producing operations. Such cogeneration operations produce electricity as a by-product from the production of steam. In each monthly accounting period, the cost of operating the cogeneration facilities, up to the amount of the electricity sales, is considered operating costs from electricity generation. Costs in excess of electricity revenue during each period, if any, are considered cost of producing steam and are reported in operating costs – oil and gas production. Also, electricity revenue represents sales to customers only. It does not include the value of the electricity utilized as power to run the Company’s field operations.

Conventional Steam Costs

The costs of producing conventional steam are included in “Operating costs – oil and gas production.”

Revenue Recognition

Revenues associated with sales of crude oil, natural gas, and electricity are recognized when title passes to the customer, net of royalties, discounts and allowances, as applicable. Electricity and natural gas produced by the Company and used in the Company’s operations are not included in revenues. Revenues from crude oil and natural gas production from properties in which the Company has an interest with other producers are recognized on the basis of the Company's net working interest (entitlement method).

Shipping and Handling Costs

Shipping and handling costs, which consist primarily of natural gas transportation costs, are included in both "Operating costs - oil and gas production" or "Operating costs - electricity generation,” as applicable. Natural gas transportation costs included in these categories were $4.0 million, $1.4 million, and $1.2 million for 2003, 2002 and 2001, respectively.

2. Summary of Significant Accounting Policies (cont'd)

Stock-Based Compensation

In accordance with the provisions of SFAS No. 123, “Accounting for Stock-Based Compensation,” the Company measures compensation cost using the variable method of accounting prescribed by Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees,” and related interpretations to account for its stock option plan. As the Company had permitted option holders to exercise options by surrendering underlying unexercised options in payment of the exercise price of the options and related taxes, variable plan accounting is required under generally accepted accounting principles in the United States. As a result, while no compensation cost has been recognized at the grant date as the exercise price of all stock option grants was equal to 100% of the market price of the Company’s common stock as of the date of grant, subsequent changes in the market price of the Company’s stock to the date of exercise or forfeiture result in a change in the measure of compensation cost for the award being recognized. In December 2002, the Financial Accounting Standards Board issued Financial Accounting Standards No. 148, *Accounting for Stock-Based Compensation – Transition and Disclosure* (SFAS No. 148). SFAS No. 148 amends SFAS No. 123 to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. The amendments to SFAS No. 123 are effective for financial statements for fiscal years ending after December 15, 2002..

Had compensation cost for the Company’s stock based compensation plan (see Note 12) been based upon the fair value at the grant dates for awards under the plan consistent with SFAS No. 123, the Company’s compensation cost, net of related tax effects, net income and earnings per share would have been recorded as the pro forma amounts indicated below (in thousands, except per share data):

	2003 (Restated)	2002 (Restated)	2001 (Restated)
Compensation cost, net of income taxes:			
As reported	$ 2,335	$ 806	$ 979
Pro forma	1,323	701	758
Net income:			
As reported	32,363	29,210	20,985
Pro forma	33,375	29,315	21,206
Basic net income per share:			
As reported	1.49	1.34	0.96
Pro forma	1.53	1.35	0.97
Diluted net income per share:			
As reported	1.47	1.33	0.95
Pro forma	1.52	1.34	0.96

Under SFAS No. 123, compensation cost would be recognized for the fair value of the employee's option rights. The fair value of each option grant was estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions:

	2003	2002	2001
Yield	2.87%	2.55%	2.72%
Expected option life – years	7.0	7.5	7.5
Volatility	27.87%	33.45%	38.71%
Risk-free interest rate	3.86%	4.09%	4.65%

2. Summary of Significant Accounting Policies (cont'd)

Income Taxes

Income taxes are provided based on the liability method of accounting. The provision for income taxes is based on pre-tax financial accounting income. Deferred tax assets and liabilities are recognized for the future expected tax consequences of temporary differences between income tax and financial reporting, and principally relate to differences in the tax bases of assets and liabilities and their reported amounts using enacted tax rates in effect for the year in which differences are expected to reverse. If it is more likely than not that some portion or all of a deferred tax asset will not be realized, a valuation allowance is recognized.

Net Income Per Share

Basic net income per share is computed by dividing income available to common shareholders (the numerator) by the weighted average number of shares of capital stock outstanding (the denominator). The Company's Class B stock is included in the denominator of basic and diluted net income. The computation of diluted net income per share is similar to the computation of basic net income per share except that the denominator is increased to include the dilutive effect of the additional common shares that would have been outstanding if all convertible securities had been converted to common shares during the period.

Recent Accounting Developments

In the fourth quarter of 2002, the Company adopted the supplemental disclosure requirements of SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure," which amended SFAS No. 123, "Accounting for Stock-Based Compensation." The Company records compensation related to employee stock options under APB Opinion No. 25, "Accounting for Stock Issued to Employees." SFAS No. 148 encourages companies to voluntarily elect to record the compensation based on market value either prospectively, as defined in SFAS No. 123, or retroactively or in a modified prospective method. The Company uses the Black-Scholes model to calculate and disclose the market value of its options granted.

In November 2002 the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others ("FIN 45")." This Interpretation addresses the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees. In addition, the Interpretation clarifies the requirements related to the recognition of a liability by a guarantor at the inception of a guarantee for the obligations that the guarantor has undertaken in issuing the guarantee. The Company adopted the disclosure requirements of FIN 45 for the fiscal year ended December 31, 2002, and the recognition provisions on January 1, 2003. Adoption of this Interpretation did not have a material impact on the Company's Financial Statements.

In June 2002 the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities," which addresses accounting for restructuring and similar costs. SFAS No. 146 supersedes previous accounting guidance, principally EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (Including Certain Costs Incurred in a Restructuring)." The Company has adopted, effective January 1, 2003, the provisions of SFAS No. 146 for restructuring activities initiated after December 31, 2002. SFAS No. 146 requires that the liability for costs associated with an exit or disposal activity be recognized when the liability is incurred. Under EITF No. 94-3, a liability for an exit cost was recognized at the date of commitment to an exit plan. SFAS No. 146 also establishes that the liability should initially be measured and recorded at fair value. Accordingly, SFAS No. 146 may affect the timing of recognizing future restructuring costs as well as the amounts recognized. SFAS No. 146 did not have a material impact on the Company's Financial Statements.

2. Summary of Significant Accounting Policies (cont'd)

In April 2003 the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS No. 149 amends and clarifies financial reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under SFAS No. 133. SFAS No. 149 clarifies under what circumstances a contract with an initial net investment meets the characteristic of a derivative, clarifies when a derivative contains a financing component, amends the definition of an underlying to conform it to language used in FIN 45, and amends certain other existing pronouncements. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003, and should be applied prospectively, with the exception of certain SFAS No. 133 implementation issues that were effective for all fiscal quarters prior to June 15, 2003. Any such implementation issues should continue to be applied in accordance with their respective effective dates. The adoption of SFAS No. 149 did not have a material impact on the Company's financial statements.

During January 2003, the Financial Accounting Standards Board issued Interpretation No. 46, "Consolidation of Variable Interest Entities" ("FIN 46"), which requires the consolidation of certain entities that are determined to be variable interest entities ("VIE's"). An entity is considered to be a VIE when either (i) the entity lacks sufficient equity to carry on its principal operations, (ii) the equity owners of the entity cannot make decisions about the entity's activities or (iii) the entity's equity neither absorbs losses or benefits from gains. The Company has reviewed its financial arrangements and has not identified any material VIE's that should be consolidated by the Company in accordance with FIN 46.

Reclassifications

Certain reclassifications have been made to the 2002 and 2001 financial statements to conform with the 2003 presentation.

3. Fair Value of Financial Instruments

Cash equivalents consist principally of commercial paper investments. Cash equivalents of $10.6 million and $9.8 million at December 31, 2003 and 2002, respectively, are stated at cost, which approximates market.

The Company's short-term investments available for sale at December 31, 2003 and 2002 consist of United States treasury notes that mature in less than one year and are carried at fair value. For the three years ended December 31, 2003, realized and unrealized gains and losses were insignificant to the financial statements. A United States treasury note with a market value of $.6 million is pledged as collateral to the California State Lands Commission as a performance bond on the Company's Montalvo properties. The carrying value of the Company's long-term debt approximates its fair value since it is carried at current interest rates.

In 2001, the Company established an oil price hedge on 3,000 barrels per day for a one-year period beginning on June 1; and a natural gas price hedge on 5,000 MMBtu/D for a three-year period beginning on August 1. Both of these hedges were with Enron as the counterparty. On December 10, 2001, after Enron filed for bankruptcy, the Company elected to terminate all contracts with Enron and agreed with Enron as to the value of the contracts as of the termination date. Based on this agreed value, the Company recorded a pre-tax charge of $1.5 million in the fourth quarter of 2001 and recorded a liability of $1.3 million, which was remitted upon the approval of the termination agreement in the Enron bankruptcy proceedings. The Company had a signed International Swap Dealer's Association master agreement with Enron, which allowed for the netting of any receivables and liabilities arising thereunder.

To protect the Company's revenues from potential price declines, the Company periodically enters into hedge contracts covering up to 50% of production. As a result of hedging activities, the Company's revenue was reduced by $11.8 million, $3.8 million, and $0 in 2003, 2002 and 2001, respectively, which was reported in "Sales of oil and gas" in the Company's financial statements.

4. Concentration of Credit Risks

The Company sells oil, gas and natural gas liquids to pipelines, refineries and major oil companies and electricity to major utility companies. Credit is extended based on an evaluation of the customer's financial condition and historical payment record.

4. Concentration of Credit Risks (Cont'd)

Primarily due to the Company's ability to deliver significant volumes of crude oil over a multi-year period, the Company was able to secure a three-year sales agreement, beginning in April 2000, whereby the Company sold in excess of 80% of its production under a negotiated pricing mechanism. This contract was renegotiated during 2002 and extended through December 31, 2005. Over 90% of the Company's current California production is subject to this new contract. Pricing in the new agreement is based upon the higher of the average of the local field posted prices plus a premium, or WTI minus a fixed differential. Both methods are calculated using a monthly determination. In addition to providing a premium above field postings, the agreement effectively eliminates the Company's exposure to the risk of widening WTI-heavy crude price differentials.

For the three years ended December 31, 2003, the Company has experienced no credit losses on the sale of oil, gas and natural gas liquids. However, the Company did experience a loss on its electricity sales in 2001. The Company assigned all of its rights, title and interest in its $12.1 million past due receivables from Pacific Gas and Electric Company to an unrelated party for $9.3 million, resulting in a pre-tax loss of $2.8 million. In addition, at December 31, 2001, the Company was owed $13.5 million from Southern California Edison (Edison) for past due electricity sales. The Company wrote off $3.6 million of this balance in March 2001. In March 2002, the Company was paid the total amount due from Edison plus interest resulting in pre-tax income of $4.2 million recorded in the first quarter of 2002.

The Company places its temporary cash investments with high quality financial institutions and limits the amount of credit exposure to any one financial institution. For the three years ended December 31, 2003, the Company has not incurred losses related to these investments. With respect to the Company's hedging activities, the Company utilizes more than one counterparty on its hedges and monitors each counterparty's credit rating.

The following summarizes the accounts receivable balances at December 31, 2003 and 2002 and sales activity with significant customers for each of the years ended December 31, 2003, 2002 and 2001 (in thousands). The Company does not believe that the loss of any one customer would impact the marketability of its oil, gas, natural gas liquids or electricity sold. However, the Company can make no assurances regarding the pricing of any new sales agreement.

	Accounts Receivable		Sales For the Year Ended December 31,		
Customer	December 31, 2003	December 31, 2002	2003	2002	2001
Oil & Gas Sales:					
A	$ 12,887	$ 10,714	$ 142,422	$ 94,870	$ 83,336
B	-	621	680	5,463	4,858
C	-	-	-	10,188	14,962
D	2,256	-	5,566	-	-
E	625	-	6,524	-	-
	$ 15,768	$ 11,335	$ 155,192	$ 110,521	$ 103,156
Electricity Sales:					
F	$ 2,970	$ -	$ 24,616	$ -	$ 6,859
G	2,156	1,795	20,334	15,199	21,257
H	-	1,573	265	12,317	6,279
	$ 5,126	$ 3,368	$ 45,215	$ 27,516	$ 34,395

Sales amounts will not agree to the Statements of Income due primarily to the effects of hedging and a revenue sharing royalty paid on a portion of the Company's Midway-Sunset crude oil sales, which is netted in "Sales of oil and gas" on the Statements of Income.

5. Oil and Gas Properties, Buildings and Equipment

Oil and gas properties, buildings and equipment consist of the following at December 31 (in thousands):

	2003	2002
Oil and gas:		
Proved properties:		
Producing properties, including intangible drilling costs	$ 238,303	$ 180,942
Lease and well equipment[1]	191,664	160,264
	429,967	341,206
Unproved properties		
Properties, including intangible drilling costs	2,925	6,725
Lease and well equipment	10	653
	2,935	7,378
	432,902	348,584
Less accumulated depreciation, depletion and amortization	139,514	121,695
	293,388	226,889
Commercial and other:		
Land	333	173
Buildings and improvements	3,703	3,838
Machinery and equipment	4,266	3,922
	8,302	7,933
Less accumulated depreciation	6,539	6,347
	1,763	1,586
	$ 295,151	$ 228,475

[1] *Includes cogeneration facility costs.*

The following sets forth costs incurred for oil and gas property acquisition, development and exploration activities, whether capitalized or expensed (in thousands):

	2003	2002	2001
Property acquisitions			
Proved properties	$ 50,822	$ 186	$ 2,273
Unproved properties	379	5,694	-
Development [1]	41,369	29,133	15,875
Exploration	788	1,684	-
	$ 93,358	$ 36,697	$ 18,148

[1] *Development costs include $.9 million, $.5 million and $1.0 million that were charged to expense during 2003, 2002 and 2001, respectively.*

In 2003, the Company purchased leases totaling 45,380 acres in the Brundage Canyon field in Utah for approximately $45 million and the McVan property totaling 560 acres in the Poso Creek field in Kern County, California for approximately $2.6 million. Approximately 14 million equivalent barrels of proved reserves were added by 2003 acquisitions and property development. The Company capitalized approximately $2.6 million in future abandonment obligations related to the 2003 acquisitions.

In 2002, the Company acquired approximately 262,000 acres for the potential development of CBM natural gas production in Kansas and Illinois for approximately $6 million. The Company has written off two pilot projects and impaired the acreage for a total pre-tax write off of $4.2 million in 2003 and recovered part of the cost through the sale of approximately 43,000 acres in Kansas in 2003 for $1.7 million at minimal gain to the Company. No reserves were recorded at year-end associated with the CBM related acreage. However, the Company added 4.2 MMBOE of proved reserves through its 2002 development expenditures, principally on its California properties.

5. Oil and Gas Properties, Buildings and Equipment (Cont'd)

In 2001, the Company acquired a 15.8% non-operated working interest in CBM natural gas properties in Wyoming for $2.2 million and a producing property adjacent to Berry's core Midway-Sunset properties for $.1 million. In 2001, approximately 1.1 million equivalent barrels of proved reserves were added by these acquisitions and property development.

Results of operations from oil and gas producing and exploration activities (in thousands):	2003	2002	2001
Sales to unaffiliated parties	$ 135,848	$ 102,026	$ 100,146
Production costs	(60,705)	(44,604)	(40,281)
Depreciation, depletion and amortization	(20,215)	(16,124)	(16,175)
Dry hole, abandonment and impairment	(4,195)	-	-
	50,733	41,298	43,690
Income tax expenses	(8,246)	(7,933)	(10,740)
Results of operations from producing and exploration activities	$ 42,487	$ 33,365	$ 32,950

6. Debt Obligations

Long-term debt for the years ended December 31 (in thousands):	2003	2002
Revolving bank facility	$ 50,000	$ 15,000

On July 10, 2003, the Company entered into a new Credit Agreement (the Agreement) with a banking syndicate, replacing an existing credit agreement which was due to expire in January 2004. The Agreement is a revolving credit facility for up to $200 million with ten banks. At December 31, 2003 and 2002, the Company had $50 and $15 million, respectively, outstanding under the Agreement and the predecessor agreement. In addition to the $50 million in borrowings under the Agreement, the Company has $.3 million of outstanding Letters of Credit and the remaining credit available under the Agreement is therefore, $149.7 million at December 31, 2003. The maximum amount available is subject to an annual redetermination of the borrowing base in accordance with the lender's customary procedures and practices. Both the Company and the banks have bilateral rights to one additional redetermination each year. The agreement matures on July 10, 2006. Interest on amounts borrowed is charged at LIBOR plus a margin of 1.25% to 2.00%, or the higher of the lead bank's prime rate or the federal funds rate plus 50 basis points plus a margin of 0.0% to 0.75%, with margins on the various rate options based on the ratio of credit outstanding to the borrowing base. The Company pays a commitment fee of 30 to 50 basis points on the unused portion, which is also based on the ratio of credit outstanding to the borrowing base.

The weighted average interest rate on outstanding borrowings at December 31, 2003 was 2.58%. The Agreement contains restrictive covenants which, among other things, requires the Company to maintain a certain tangible net worth and minimum EBITDA, as defined. The Company was in compliance with all such covenants as of December 31, 2003.

7. Shareholders' Equity

Shares of Class A Common Stock (Common Stock) and Class B Stock, referred to collectively as the "Capital Stock," are each entitled to one vote and 95% of one vote, respectively. Each share of Class B Stock is entitled to a $1.00 per share preference in the event of liquidation or dissolution. Further, each share of Class B Stock is convertible into one share of Common Stock at the option of the holder.

In November 1999, the Company adopted a Shareholder Rights Agreement and declared a dividend distribution of one Right for each outstanding share of Capital Stock on December 8, 1999. Each Right, when exercisable, entitles the holder to purchase one one-hundredth of a share of a Series B Junior Participating Preferred Stock, or in certain cases other securities, for $38.00. The exercise price and number of shares issuable are subject to adjustment to prevent dilution. The Rights would become exercisable, unless earlier redeemed by the Company, 10 days following a public announcement that a person or group has acquired, or obtained the right to acquire, 20% or more of the outstanding shares of Common Stock or 10 business days following the commencement of a tender or exchange offer for such outstanding shares which would result in such person or group acquiring 20% or more of the outstanding shares of Common Stock, either event occurring without the prior consent of the Company.

7. Shareholders' Equity (Cont'd)

The Rights will expire on December 8, 2009 or may be redeemed by the Company at $.01 per Right prior to that date unless they have theretofore become exercisable. The Rights do not have voting or dividend rights, and until they become exercisable, have no diluting effect on the earnings of the Company. A total of 250,000 shares of the Company's Preferred Stock has been designated Series B Junior Participating Preferred Stock and reserved for issuance upon exercise of the Rights. This Shareholder Rights Agreement replaced the previous Shareholder Rights Agreement approved in December 1989 which expired on December 8, 1999.

In August 2001, the Board of Directors authorized the Company to repurchase $20 million of Common Stock in the open market. As of December 31, 2001, the Company had repurchased 308,075 shares for approximately $5.1 million. All shares repurchased were retired. No additional shares were repurchased in 2002 or 2003.

The Company issued 51,683, 19,717, and 6,529 shares in 2003, 2002, and 2001, respectively, through its stock option plan.

The Company paid a special dividend of $.04 per share on May 2, 2003 and increased its regular quarterly dividend by 10%, from $.10 to $.11 per share beginning with the June 2003 dividend.

As of December 31, 2003, dividends declared on 4,000,894 shares of certain Common Stock are restricted, whereby 37.5% of the dividends declared on these shares are paid by the Company to the surviving member of a group of individuals, the B Group, as long as this remaining member shall live.

8. Asset Retirement Obligations

In 2002, the Company implemented SFAS No. 143, "Accounting for Asset Retirement Obligations" for recording future site restoration costs related to its oil and gas properties. Prior to its implementation, the Company had recorded the future obligation per SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." Under SFAS No. 143, the following table summarizes the change in our abandonment obligation for the year ended December 31, 2003 (in thousands):

	2003
Beginning abandonment obligation December 31, 2002	$ 4,596
Liabilities incurred	2,623
Liabilities settled	(439)
Accretion expense	531
Ending abandonment obligation December 31, 2003	$ 7,311

9. Income Taxes

The Provision for income taxes consists of the following (in thousands):

	2003 (Restated)	2002 (Restated)	2001 (Restated)
Current:			
Federal	$ 2,490	$ 2,340	$ 3,612
State	619	894	1,300
	3,109	3,234	4,912
Deferred:			
Federal	$ 2,027	$ 4,286	$ (332)
State	(531)	(403)	129
	1,496	3,883	(203)
Total	$ 4,605	$ 7,117	$ 4,709

9. Income Taxes (cont'd)

The current deferred tax assets and liabilities are offset and presented as a single amount in the financial statements. Similarly, the non-current deferred tax assets and liabilities are presented in the same manner. The following table summarizes the components of the total deferred tax assets and liabilities before such financial statement offsets. The components of the net deferred tax liability consist of the following at December 31 (in thousands):

	2003 (Restated)	2002 (Restated)
Deferred tax asset:		
Federal benefit of state taxes	$ 318	$ 350
Credit/deduction carryforwards	23,440	15,454
Stock option costs	2,185	1,251
Derivatives	2,421	1,712
Other, net	1,488	(1,187)
	29,852	17,580
Deferred tax liability:		
Depreciation and depletion	(61,425)	(49,458)
Other, net	(253)	27
	(61,678)	(49,431)
Net deferred tax liability	$ (31,826)	$ (31,851)

Reconciliation of the statutory federal income tax rate to the effective income tax rate follows.

	2003 (Restated)	2002 (Restated)	2001 (Restated)
Tax computed at statutory federal rate	35%	35%	35%
State income taxes, net of federal benefit	1	1	1
Tax credits	(24)	(15)	(17)
Other	-	(1)	(1)
Effective tax rate	12%	20%	18%

The Company has approximately $20 million of federal and $11 million of state (California) EOR tax credit carryforwards available to reduce future income taxes. The EOR credits will begin to expire in 2020 and 2014 for federal and California, respectively.

10. Commitments

Operating Leases – Office Space

The Company leases corporate and field offices in California and the Rocky Mountain region. The total minimum rental payments, on a combined basis, for these leases are as follows (in thousands):

Year ending December 31,	
2004	$ 528
2005	562
2006	487
2007	107
2008	107
2009	90
Total	$ 1,881

Firm Transportation-Natural Gas Purchases

The Company entered into a 12,000 MMBtu/D ten-year firm transportation agreement on the Kern River pipeline with gas deliveries commencing in May 2003. This firm transportation provides the Company additional flexibility in securing its natural gas supply and allows the Company to potentially benefit from discounted natural gas prices in the Rockies. As of December 31, 2003, this take-or-pay commitment was approximately $29 million over the remaining term of the contract.

11. Contingencies

The Company has accrued environmental liabilities for all sites, including sites in which governmental agencies have designated the Company as a potentially responsible party, where it is probable that a loss will be incurred and the minimum cost or amount of loss can be reasonably estimated. However, because of the uncertainties associated with environmental assessment and remediation activities, future expense to remediate the currently identified sites, and sites identified in the future, if any, could be higher than the liability currently accrued. Amounts currently accrued are not significant to the consolidated financial position of the Company and Management believes, based upon current site assessments, that the ultimate resolution of these matters will not require substantial additional accruals. The Company is involved in various other lawsuits, claims and inquiries, most of which are routine to the nature of its business. In the opinion of Management, the resolution of these matters will not have a material effect on the Company’s financial position, results of operations or liquidity.

12. Stock Option Plan

On December 2, 1994, the Board of Directors of the Company adopted the Berry Petroleum Company 1994 Stock Option Plan which was restated and amended in December 1997 and December 2001 (the 1994 Plan) and approved by the shareholders in May 1998 and May 2002, respectively. The 1994 Plan provides for the granting of stock options to purchase up to an aggregate of 3,000,000 shares of Common Stock. All options, with the exception of the formula grants to non-employee Directors, will be granted at the discretion of the Compensation Committee of the Board of Directors. The term of each option may not exceed ten years from the date the option is granted.

The options vest 25% per year for four years. The 1994 Plan also allows for option grants to the Board of Directors under a formula plan whereby all non-employee Directors receive 5,000 options annually on December 2nd at the fair value on the date of grant. The options granted to the non-employee Directors vest immediately.

12. Stock Option Plan (Cont'd)

The following is a summary of stock-based compensation activity for the years 2003, 2002 and 2001.

	2003 Options	2002 Options	2001 Options
Balance outstanding, January 1	1,604,575	1,474,962	1,407,837
Granted	411,500	241,200	239,500
Exercised	(294,150)	(95,837)	(65,125)
Canceled/expired	(20,000)	(15,750)	(107,250)
Balance outstanding, December 31	1,701,925	1,604,575	1,474,962
Balance exercisable at December 31	1,037,275	1,153,000	1,010,712
Available for future grant	615,600	1,007,100	232,550
Exercise price-range	$15.10 to 20.30	$16.56 to 18.05	$14.40 to 16.96
Weighted average remaining contractual life (years)	7	7	7
Weighted average fair value per option granted during the year based on the Black-Scholes pricing model	$5.11	$5.25	$5.87

Weighted average option exercise price information for the years 2003, 2002 and 2001 as follows.

	2003	2002	2001
Outstanding at January 1	$ 15.17	$ 14.80	$ 14.58
Granted during the year	19.31	16.14	16.16
Exercised during the year	13.15	11.87	13.12
Cancelled/expired during the year	16.55	15.92	16.01
Outstanding at December 31	16.50	15.17	14.80
Exercisable at December 31	15.62	14.81	14.55

13. Retirement Plan

The Company sponsors a 401(k) defined contribution thrift plan to assist all eligible employees in providing for retirement or other future financial needs. Employee contributions (up to 6% of earnings) are matched by the Company dollar for dollar. Effective November 1, 1992, the 401(k) Plan was modified to provide for increased Company matching of employee contributions whereby the monthly Company matching contributions will range from 6% to 9% of eligible participating employee earnings, if certain financial targets are achieved. The Company's contributions to the 401(k) Plan were $.5 million in 2003, $.4 million in 2002, and $.4 million in 2001. On average, approximately 96% of eligible employees participate in the plan.

14. Restatement of Financial Information

The Company has restated its financial statements to account for the Company's stock option plan using variable plan accounting, insofar as the Company had permitted option holders to exercise options by surrendering underlying unexercised options in payment of the exercise price of the options and related taxes. While the Company had accounted for options issued under the plan as fixed awards with compensation expense recorded for certain option exercises, it has been determined that variable plan accounting is required under generally accepted accounting principles in the United States. The use of variable plan accounting requires a charge to compensation expense, commencing at the grant date, in an amount by which the market price of the Company's stock covered by the grant exceeds the option price. This accounting continues and subsequent changes in the market price of the Company's stock from the date of grant to the date of exercise or forfeiture result in a change in the measure of compensation cost for the award being recognized but not resulting in an accumulated adjustment below zero. These adjustments are reflected in the financial statements with the cumulative adjustment to Shareholders' Equity as of January 1, 2001 resulting in an increase in Capital in Excess of Par Value of $.4 million, increase in Deferred Stock Based Compensation of $.1 million and decrease in Retained Earnings of $.3 million. As a result of the restatement, Capital in Excess of Par Value was increased by $6.7 million, $3.2 million, and $1.8 million as of December 31, 2003, 2002, and 2001, respectively. Deferred Stock-Based Compensation increased by $1.0 million, $.3 million and $.1 million as of December 31, 2003, 2002, and 2001, respectively. Retained Earnings decreased by $4.1 million, $2.1 million and $1.3 million as of December 31, 2003, 2002, and 2001, respectively. The adjustments decreased the Company's net income by $2.0 million, or $0.09 per share (diluted) in 2003, $.8 million, or $0.04 per share (diluted) in 2002, and $1.0 million, or $0.04 per share (diluted) in 2001.

14. Restatement of Financial Information (Cont'd)

The following sets forth the effects of the aforementioned restatements to the Company's Balance Sheet at December 31, 2003 and December 31, 2002, and its Income Statements and Statements of Cash Flows for the years ended December 31, 2003, 2002 and 2001.

CONDENSED BALANCE SHEETS (In Thousands)

	December 31, 2003		
	As Previously Reported	Adjustments	As Restated
ASSETS			
Deferred income taxes	$ 4,410	$ 2,000	$ 6,410
Other assets	$ 1,755	$ 185	$ 1,940
Total assets	$ 338,192	$ 2,185	$ 340,377
LIABILITIES AND SHAREHOLDERS' EQUITY			
Income taxes payable	$ 4,238	$ 174	$ 4,412
Deferred income taxes	$ 38,168	$ 391	$ 38,559
Total liabilities	142,474	565	143,039
Capital stock	218	-	218
Capital in excess of par value	49,678	5,689	55,367
Accumulated other comprehensive loss	(3,632)	-	(3,632)
Retained earnings	149,454	(4,069)	145,385
Total liabilities and shareholders' equity	$ 338,192	$ 2,185	$ 340,377

	December 31, 2002		
	As Previously Reported	Adjustments	As Restated
ASSETS			
Deferred income taxes	$ 844	$ 1,186	$ 2,030
Other assets	$ 893	$ 66	$ 959
Total assets	$ 258,073	$ 1,252	$ 259,325
LIABILITIES AND SHAREHOLDERS' EQUITY			
Income taxes payable	$ 2,612	$ 389	$ 3,001
Deferred income taxes	$ 33,866	$ 147	$ 34,013
Total liabilities	86,015	536	86,551
Capital stock	218	-	218
Capital in excess of par value	49,052	2,816	51,868
Accumulated other comprehensive loss	(2,569)	-	(2,569)
Retained earnings	125,357	(2,100)	123,257
Total liabilities and shareholders' equity	$ 258,073	$ 1,252	$ 259,325

14. Restatement of Financial Information (Cont'd)

CONDENSED INCOME STATEMENTS (In Thousands)

	December 31, 2003		
	As Previously Reported	Adjustments	As Restated
REVENUES	$ 180,864	$ -	$ 180,864
EXPENSES			
Operating costs	104,905	-	104,905
Depreciation, depletion & amortization	20,514	-	20,514
General & administrative	9,586	3,282	12,868
Interest	1,414	-	1,414
Other expenses	4,195	-	4,195
	140,614	3,282	143,896
Income before income taxes	40,250	(3,282)	36,968
Provision for income taxes	5,918	(1,313)	4,605
Net income	$ 34,332	$ (1,969)	$ 32,363
Basic net income per share	$ 1.58	$ (0.09)	$ 1.49
Diluted net income per share	$ 1.56	$ (0.09)	$ 1.47
Weighted average shares of capital stock outstanding (used to calculate basic net income per share)	21,772		21,772
Effect of dilutive securities			
Stock options	204		204
Other	44		44
Weighted average shares of capital stock outstanding (used to calculate diluted net income per share)	22,020		22,020

CONDENSED INCOME STATEMENTS (In Thousands)

	Year ended December 31, 2002		
	As Previously Reported	Adjustments	As Restated
REVENUES	$ 131,369	$ -	$ 131,369
EXPENSES			
Operating costs	71,964	-	71,964
Depreciation, depletion & amortization	16,452	-	16,452
General & administrative	7,928	1,287	9,215
Interest	1,042	-	1,042
Other expenses	(3,631)	-	(3,631)
	93,755	1,287	95,042
Income before income taxes	37,614	(1,287)	36,327
Provision for income taxes	7,590	(473)	7,117
Net income	$ 30,024	$ (814)	$ 29,210
Basic net income per share	$ 1.38	$ (0.04)	$ 1.34
Diluted net income per share	$ 1.37	$ (0.04)	$ 1.33
Weighted average shares of capital stock outstanding (used to calculate basic net income per share)	21,741		21,741
Effect of dilutive securities			
Stock options	156		156
Other	42		42
Weighted average shares of capital stock outstanding (used to calculate diluted net income per share)	21,939		21,939

CONDENSED INCOME STATEMENTS (In Thousands)

	Year ended December 31, 2001		
	As Previously Reported	Adjustments	As Restated
REVENUES	$ 137,757	$ -	$ 137,757
EXPENSES			
Operating costs	75,003	-	75,003
Depreciation, depletion & amortization	16,520	-	16,520
General & administrative	7,174	1,544	8,718
Interest	3,719	-	3,719
Write-off of electricity receivable	6,645	-	6,645
Other expenses	1,458	-	1,458
	110,519	1,544	112,063
Income before income taxes	27,238	(1,544)	25,694
Provision for income taxes	5,300	(591)	4,709
Net income	$ 21,938	$ (953)	$ 20,985
Basic net income per share	$ 1.00	$ (0.04)	$ 0.96
Diluted net income per share	$ 0.99	$ (0.04)	$ 0.95
Weighted average shares of capital stock outstanding (used to calculate basic net income per share)	21,973		21,973
Effect of dilutive securities			
Stock options	113		113
Other	24		24
Weighted average shares of capital stock outstanding (used to calculate diluted net income per share)	22,110		22,110

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

14. Restatement of Financial Information (Cont'd)

CONDENSED STATEMENTS OF CASH FLOWS (In Thousands)

	Year ended December 31, 2003		
	As Previously Reported	Adjustments	As Restated
Cash flows from operating activities:			
Net income	$ 34,332	$ (1,969)	$ 32,363
Adjustments to reconcile net income to net cash provided in operating activities	30,493	1,969	32,462
Net cash provided by operating activities	64,825	-	64,825
Cash flows from investing activities:			
Net cash used in investing activities	(87,723)	-	(87,723)
Cash flows from financing activities:			
Net cash provided by financing activities	23,690	-	23,690
Net increase in cash and cash equivalents	792	-	792
Cash and cash equivalents at beginning of year	9,866	-	9,866
Cash and cash equivalents at end of year	$ 10,658	$ -	$ 10,658

	Year ended December 31, 2002		
	As Previously Reported	Adjustments	As Restated
Cash flows from operating activities:			
Net income	$ 30,024	$ (814)	$ 29,210
Adjustments to reconcile net income to net cash provided in operating activities	27,871	814	28,685
Net cash provided by operating activities	57,895	-	57,895
Cash flows from investing activities:			
Net cash used in investing activities	(36,526)	-	(36,526)
Cash flows from financing activities:			
Net cash used in financing activities	(18,741)	-	(18,741)
Net increase in cash and cash equivalents	2,628	-	2,628
Cash and cash equivalents at beginning of year	7,238	-	7,238
Cash and cash equivalents at end of year	$ 9,866	$ -	$ 9,866

14. Restatement of Financial Information (Cont'd)

CONDENSED STATEMENTS OF CASH FLOWS (In Thousands)

	Year ended December 31, 2001		
	As Previously Reported	Adjustments	As Restated
Cash flows from operating activities:			
Net income	$ 21,938	$ (953)	$ 20,985
Adjustments to reconcile net income to net cash provided in operating activities	13,495	953	14,448
Net cash provided by operating activities	35,433	-	35,433
Cash flows from investing activities:			
Net cash used in investing activities	(17,029)	-	(17,029)
Cash flows from financing activities:			
Net cash used in financing activities	(13,897)	-	(13,897)
Net increase in cash and cash equivalents	4,507	-	4,507
Cash and cash equivalents at beginning of year	2,731	-	2,731
Cash and cash equivalents at end of year	$ 7,238	$ -	$ 7,238

15. Quarterly Financial Data (unaudited)

The following is a tabulation of unaudited quarterly operating results for 2003 and 2002 (in thousands, except per share data). Net income and per share amounts have been restated as discussed more fully in Note 14 to the financial statements. The impact of these adjustments on the Company's quarterly financial results are as follows:

	As Previously Reported				Adjustments				As Restated			
	Operating	Gross	Net	Per Share	Operating	Gross	Net	Per Share	Operating	Gross	Net	Per Share
2003	Revenues	Profit	Income	(Diluted)	Revenues	Profit	Income	(Diluted)	Revenues	Profit	Income	(Diluted)
First Quarter	$ 46,766	$ 16,790	$ 9,177	$ 0.42	$ -	$ -	$ 1,098	$ 0.05	$ 46,766	$ 16,790	$ 10,275	$ 0.47
Second Quarter	39,372	9,187	6,510	0.30	-	-	(1,605)	(0.08)	39,372	9,187	4,905	0.22
Third Quarter	44,108	11,842	8,035	0.36	-	-	(208)	(0.01)	44,108	11,842	7,827	0.35
Fourth Quarter	49,802	17,110	10,610	0.48	-	-	(1,254)	(0.06)	49,802	17,110	9,356	0.42
	$ 180,048	$ 54,929	$ 34,332	$ 1.56	$ -	$ -	$ (1,969)	$ (0.09)	$ 180,048	$ 54,929	$ 32,363	$ 1.47

	As Previously Reported				Adjustments				As Restated			
	Operating	Gross	Net	Per Share	Operating	Gross	Net	Per Share	Operating	Gross	Net	Per Share
2002	Revenues	Profit	Income	(Diluted)	Revenues	Profit	Income	(Diluted)	Revenues	Profit	Income	(Diluted)
First Quarter	$ 26,807	$ 8,014	$ 8,620	$ 0.40	$ -	$ -	$ 107	$ -	$ 26,807	$ 8,014	$ 8,727	$ 0.40
Second Quarter	31,765	10,482	6,827	0.31	-	-	(755)	(0.03)	31,765	10,482	6,072	0.28
Third Quarter	34,933	12,599	7,587	0.35	-	-	(74)	-	34,933	12,599	7,513	0.35
Fourth Quarter	36,212	10,534	6,990	0.32	-	-	(92)	(0.01)	36,212	10,534	6,898	0.31
	$ 129,717	$ 41,629	$ 30,024	$ 1.37	$ -	$ -	$ (814)	$ (0.04)	$ 129,717	$ 41,629	$ 29,210	$ 1.33

BERRY PETROLEUM COMPANY

Supplemental Information About Oil & Gas Producing Activities (Unaudited)

The following estimates of proved oil and gas reserves, both developed and undeveloped, represent interests owned by the Company located solely within the United States. Proved reserves represent estimated quantities of crude oil and natural gas 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 the quantities expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells for which relatively major expenditures are required for completion.

Disclosures of oil and gas reserves which follow are based on estimates prepared by independent engineering consultants as of December 31, 2003, 2002 and 2001. Such estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. These estimates do not include probable or possible reserves. The information provided does not represent Management's estimate of the Company's expected future cash flows or value of proved oil and gas reserves.

Changes in estimated reserve quantities

The net interest in estimated quantities of proved developed and undeveloped reserves of crude oil and natural gas at December 31, 2003, 2002 and 2001, and changes in such quantities during each of the years then ended were as follows (in thousands):

	2003			2002			2001		
	Oil Mbbls	Gas Mmcf	BOE	Oil Mbbls	Gas Mmcf	BOE	Oil Mbbls	Gas Mmcf	BOE
Proved developed and Undeveloped reserves:									
Beginning of year	100,744	5,850	101,719	101,701	6,926	102,855	106,664	4,184	107,361
Revision of previous estimates	(82)	293	(33)	(30)	(307)	(81)	33	153	58
Improved recovery	1,271	-	1,271	752	-	752	-	-	-
Extensions and discoveries	1,853	2,005	2,187	3,444	-	3,444	-	-	-
Production	(5,827)	(1,277)	(6,040)	(5,123)	(769)	(5,251)	(4,996)	(288)	(5,044)
Purchase of reserves in place	8,681	12,809	10,816	-	-	-	-	2,877	480
End of year	106,640	19,680	109,920	100,744	5,850	101,719	101,701	6,926	102,855
Proved developed reserves:									
Beginning of year	72,889	3,252	73,431	79,317	3,518	79,903	81,132	1,635	81,405
End of year	78,145	12,207	80,180	72,889	3,252	73,431	79,317	3,518	79,903

Supplemental Information About Oil & Gas Producing Activities (Unaudited)(Cont'd)

The standardized measure has been prepared assuming year end sales prices adjusted for fixed and determinable contractual price changes, current costs and statutory tax rates (adjusted for tax credits and other items), and a ten percent annual discount rate. No deduction has been made for depletion, depreciation or any indirect costs such as general corporate overhead or interest expense. Cash outflows for future production and development costs include cash flows associated with the ultimate settlement of the asset retirement obligation.

Standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves (in thousands):

	2003	2002	2001
Future cash inflows	$ 2,845,767	$ 2,533,410	$ 1,452,946
Future production and development costs	(1,444,619)	(1,313,866)	(730,311)
Future income tax expenses	(324,097)	(305,485)	(171,741)
Future net cash flows	1,077,051	914,059	550,894
10% annual discount for estimated timing of cash flows	(548,831)	(464,202)	(272,441)
Standardized measure of discounted future net cash flows	$ 528,220	$ 449,857	$ 278,453
Average sales prices at December 31 (net of the effect of hedges):			
Oil ($/Bbl)	$ 25.77	$ 24.92	$ 14.16
Gas ($/Mcf)	$ 4.94	$ 3.94	$ 1.87
BOE Price	$ 25.89	$ 24.91	$ 14.13

Changes in standardized measure of discounted future net cash flows from proved oil and gas reserves (in thousands):

	2003	2002	2001
Standardized measure - beginning of year	$ 449,857	$ 278,453	$ 501,694
Sales of oil and gas produced, net of production costs	(75,143)	(57,422)	(59,865)
Revisions to estimates of proved reserves:			
Net changes in sales prices and production costs	45,292	276,417	(422,515)
Revisions of previous quantity estimates	(229)	(550)	222
Improved recovery	9,400	5,063	-
Extensions and discoveries	16,171	23,189	-
Change in estimated future development costs	(75,841)	(74,566)	48,689
Purchases of reserves in place	47,700	-	2,606
Development costs incurred during the period	41,461	30,632	14,895
Accretion of discount	59,983	35,865	72,177
Income taxes	(8,896)	(62,531)	136,303
Other	18,465	(4,693)	(15,753)
Net increase (decrease)	78,363	171,404	(223,241)
Standardized measure - end of year	$ 528,220	$ 449,857	$ 278,453

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

None.

Item 9A. Controls and Procedures

The Company's Management, with the participation of the Company's Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, subject to and except for the discussion below and elsewhere in this Form 10-K/A concerning the restatement of the Company's financial statements, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures as of the end of the period covered by this report were designed and functioning effectively to provide reasonable assurance that the information required to be disclosed by the Company in reports filed under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

The restatement of the Company's financial statements contained in this Form 10-K/A are described in Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under "Restatement of Financial Information," and in Note 14 of the Notes to the financial statements in Part II, Item 8.

In July, 2004, the Company became aware of a material weakness relating to the Company's internal controls and procedures over its financial reporting for stock based compensation relating to its stock option plan. As a result, the Company has performed a review of the method of stock option exercises by employees and directors since the plan's inception in 1994. Based on this review, the Company determined that variable plan accounting is required in order to comply with generally accepted accounting principles in the United States, which resulted in the restatement discussed in this Form 10-K/A. In response to this matter, the Company, during the third quarter 2004, has remediated the ineffective internal controls through the implementation of enhanced controls to assure that financial reporting is in compliance with generally accepted accounting principles in the United States.

No change in the Company's internal control over financial reporting occurred during the Company's fiscal quarter ended December 31, 2003 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting, except as described above.

PART III

Item 10. Directors and Executive Officers of the Registrant

The information called for by Item 10 is incorporated by reference from information under the captions "Corporate Governance and Board Matters" and "Compliance with Section 16(a) of the Securities Exchange Act of 1934" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of its fiscal year. Information regarding Executive Officers is contained in this report in Part I, Item 1 titled "Business and Properties".

Item 11. Executive Compensation

The information called for by Item 11 is incorporated by reference from information under the caption "Executive Compensation" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of its fiscal year.

Item 12. Security Ownership of Certain Beneficial Owners and Management

The information called for by Item 12 is incorporated by reference from information under the captions "Security Ownership of Directors and Management" and "Principal Shareholders" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of its fiscal year.

Item 13. Certain Relationships and Related Transactions

The information called for by Item 13 is incorporated by reference from information under the caption "Certain Relationships and Related Transactions" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of its fiscal year.

Item 14. Principal Accounting Fees and Services

The information called for by Item 14 is incorporated by reference from the information under the caption “Fees to Independent Accountants for 2003 and 2002” in the Company’s definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of its fiscal year.

Item 15 Exhibits, Financial Statement Schedules and Reports on Form 8-K

A. Financial Statements and Schedules

See Index to Financial Statements and Supplementary Data in Item 8.

B. Reports on Form 8-K

During the three months ended December 31, 2003, the Company filed one Current Report on Form 8-K dated November 6, 2003. The Company's November 6, 2003 Form 8-K provided, under Items 7 and 12, including the Company's news release and attached schedules dated November 6, 2003 that announced the Company's financial and operating results for the three and nine month periods ended September 30, 2003.

C. Exhibits

Exhibit No.	Description of Exhibit
3.1*	Registrant's Restated Certificate of Incorporation (filed as Exhibit 3.1 to the Registrant's Registration Statement on Form S-1 filed on June 7, 1989, File No. 33-29165)
3.2*	Registrant's Restated Bylaws (filed as Exhibit 3.2 to the Registrant's Registration Statement on Form S-1 on June 7, 1989, File No. 33-29165)
3.3*	Registrant's Certificate of Designation, Preferences and Rights of Series B Junior Participating Preferred Stock (filed as Exhibit A to the Registrant's Registration Statement on Form 8-A12B on December 7, 1999, File No. 778438-99-000016)
3.4*	Registrant's First Amendment to Restated Bylaws dated August 31, 1999 (filed as Exhibit 3.4 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 1-9735)
4.1*	Rights Agreement between Registrant and ChaseMellon Shareholder Services, L.L.C. dated as of December 8, 1999 (filed by the Registrant on Form 8-A12B on December 7, 1999, File No. 778438-99-000016)
10.1*	Description of Cash Bonus Plan of Berry Petroleum Company (filed as Exhibit 10.1 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 1-9735).
10.2*	Salary Continuation Agreement dated as of December 5, 1997, by and between Registrant and Jerry V. Hoffman (filed as Exhibit 10.2 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1997, File No.1-9735)
10.3*	Form of Salary Continuation Agreement dated as of December 5, 1997, by and between Registrant and Ralph J. Goehring (filed as Exhibit 10.3 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1997, File No. 1-9735)
10.4*	Form of Salary Continuation Agreements dated as of March 20, 1987, as amended August 28, 1987, by and between Registrant and selected employees of the Company (filed as Exhibit 10.12 to the Registration Statement on Form S-1 filed on June 7, 1989, File No. 33-29165)
10.5*	Instrument for Settlement of Claims and Mutual Release by and among Registrant, Victory Oil Company, the Crail Fund and Victory Holding Company effective October 31, 1986 (filed as Exhibit 10.13 to Amendment No. 1 to the Registrant's Registration Statement on Form S-4 filed on May 22, 1987, File No. 33-13240)
10.7	Credit Agreement, dated as of July 10, 2003, by and between the Registrant and Wells Fargo Bank, N.A. and other financial institutions.
10.8*	Amended and Restated 1994 Stock Option Plan (filed as Exhibit 4.1 to the Registrant's Registration Statement on Form S-8 filed on August 20, 2002, File No. 333-98379)
10.9**	Crude oil purchase contract, dated as of August 1, 2002, by and between the Registrant and Equiva Trading Company (filed as Exhibit 10.9 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002, File No. 1-9735).

Exhibits (cont'd)

Exhibit No.	Description of Exhibit
10.10*	Amended and Restated Non-Employee Director Deferred Stock and Compensation Plan (filed as Exhibit 10.10 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002, File No. 1-9735).
10.11	Purchase and sale agreement between the Registrant and Willliams Production Company (filed as Exhibit 10.11 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 1-9735)
23.1	Consent of PricewaterhouseCoopers LLP
23.2	Consent of DeGolyer and MacNaughton(filed as Exhibit 23.2 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 1-9735)
31.1	Certification of Chief Executive Officer pursuant to SEC Rule 13(a)-14(a)
31.2	Certification of Chief Financial Officer pursuant to SEC Rule 13(a)-14(a)
32.1	Certification of Chief Executive Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32.2	Certification of Chief Financial Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
99.1	Undertaking for Form S-8 Registration Statements
99.2*	Form of Indemnity Agreement of Registrant (filed as Exhibit 28.2 in Registrant's Registration Statement on Form S-4 filed on April 7, 1987, File No. 33-13240)
99.3*	Form of "B" Group Trust (filed as Exhibit 28.3 to Amendment No. 1 to Registrant's Registration Statement on Form S-4 filed on May 22, 1987, File No. 33-13240)

* Incorporated by reference

** Pursuant to 17CFR240.24b-2, confidential information has been omitted and has been filed separately with the Securities and Exchange Commission, pursuant to a Confidential Treatment Request filed with the Commission.

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereto duly authorized on August 9, 2004.

BERRY PETROLEUM COMPANY

/s/ Robert F. Heinemann	/s/ Ralph J. Goehring	/s/ Donald A. Dale
ROBERT F. HEINEMANN	RALPH J. GOEHRING	DONALD A. DALE
President and	Executive Vice President and	Controller
Chief Executive Officer	Chief Financial Officer	(Principal Accounting Officer)
	(Principal Financial Officer)	

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