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

FORM 10-K

[X] Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2002
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 February 14, 2003, the registrant had 20,860,070 shares of Class A Common Stock outstanding and the aggregate market value of the voting stock held by nonaffiliates was approximately $244,242,617. This calculation is based on the closing price of the shares on the New York Stock Exchange on February 14, 2003 of $15.60. The registrant also had 898,892 shares of Class B Stock outstanding on February 14, 2003, 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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PART I

PART I

Items 1 and 2. Business and Properties

Company Website

The Company has a website located at 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 and Proxy Statement along with 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 Kern, Los Angeles and Ventura Counties in California. Information contained in this report on Form 10-K reflects the business of the Company during the year ended December 31, 2002. In March 2002, primarily in an effort to improve its competitive position in attracting and retaining talented personnel, the Company relocated its corporate headquarters to Bakersfield, California from its properties in the South Midway-Sunset field near Taft. Management believes that these new facilities are adequate for its current operations and anticipated growth.

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 be a low-cost producer and to grow the Company's asset base strategically. To increase production and proved reserves, the Company will compete to acquire oil and gas properties with principally proved reserves with exploitation potential and will focus on the further development of its existing properties by application of enhanced oil recovery (EOR) methods, developmental drilling, well completions and remedial work. In conjunction with the goals of being a low-cost heavy oil producer and the exploitation and development of its large 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 critical part of its long-term success. Berry believes that its primary strengths are its ability to maintain a low-cost 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 intends to pursue opportunities in other basins which would establish another core area and provide for additional growth opportunities and diversification of the Company's predominantly heavy oil resource base. Consistent with this strategy, the Company announced in February 2003 that it has opened an office in Denver to identify and evaluate potential opportunities which may achieve the Company's growth goals. From time to time, the Company also hires consultants or others knowledgeable in the industry to assist the Company in identifying, evaluating and acquiring assets. The Company has approximately $130 million of unused borrowing capacity to finance acquisitions and will consider, if appropriate, the issuance of capital stock to finance future purchases.

Proved Reserves

As of December 31, 2002, the Company's estimated proved reserves were 101.7 million barrels of oil equivalent, (BOE), of which 99% are heavy crude oil, i.e., oil with an API gravity of less than 20 degrees. A significant portion of these proved reserves is owned in fee. Substantially all of the Company's reserves as of December 31, 2002 were located in California, with 74%, 20% and 5% of total proved reserves in Kern, Los Angeles and Ventura Counties, respectively. The Company's reserves have a long life of approximately 19 years, which is primarily a result of the Company's strong position in heavy crude oil (the Company's properties in the Midway-Sunset and the Placerita fields average 13 degrees API gravity and the Montalvo field averages 16 degrees API gravity). Production in 2002 was 5.3 million BOE, up 4% from 2001 production of 5 million BOE. For the five years 1998 through 2002, the Company's average annual reserve replacement rate was 102% and the acquisition, finding and development cost was $4.12 per BOE.

Operations

Berry operates all of its principal oil producing properties. 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 improves the mobility of the oil flowing to the well-bore for production. Berry utilizes cyclic steam recovery methods in the Midway-Sunset field, steam-drive in the Placerita field 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. 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 (LACT) units and either transferred into crude oil pipelines owned by other companies or, in the case of the Placerita field, transported via trucks. The point-of-sale is usually the LACT unit or truck loading facility.

Revenues

The percentage of revenues by source for the prior three years is as follows:

	2002	2001	2000
Sales of oil and gas	77%	72%	69%
Sales of electricity	22%	26%	31%
Other	1%	2%	-%

Oil Marketing

The global and California crude oil markets have remained volatile due to economic and political forces. The Organization of Petroleum Exporting Countries (OPEC) has attempted to manage crude oil prices from petroleum product demand weakness due to worldwide economic slowdowns and political instability. Product prices rose in 2002 from the low in mid-January and continued to exhibit an overall-strengthening trend during the remainder of the year. Contributing factors to the increase in prices at year-end included the potential for military conflict in Iraq and the supply disruptions in Venezuela due to a strike against its President, Hugo Chavez. Average prices for 2002 were similar to those in 2001. The NYMEX price for West Texas Intermediate (WTI), the U.S. benchmark crude oil, averaged $26.15 for 2002 compared to $25.95 for 2001 and $30.26 in 2000. The range for the year 2002 was broad, however, with a low of $17.97 and a high of $32.72. The average posted price for the Company's 13 degree API heavy crude oil was $20.67 for 2002 compared to $18.70 for 2001 and $23.90 for 2000. The range of posted prices for the Company's heavy crude oil in 2002 included a low of $11.75 and a high of $26.75.

While crude oil price differentials between WTI and California's heavy crude widened slightly during the two previous years, the trend reversed in 2002. The crude price differential between WTI and California's heavy crude oil has averaged $5.48, $7.25 and $6.36 for 2002, 2001 and 2000, respectively. A price-sensitive royalty burdens one of the Company's properties which produces in excess of 3,000 BPD. The royalty was 75% of the heavy oil posted price above $14.30 in 2002. This price is escalated 2% annually.

Berry markets its crude oil production to competing buyers including independent marketing, pipeline and oil refining companies. 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, with a major California refiner whereby the Company sells in excess of 80% of its production under a negotiated pricing mechanism. This contract was renegotiated during 2002 and extended through 2005. Over 90% of the Company's current 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 bonus, 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 NYMEX WTI pricing.

From time to time, the Company enters into crude oil 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. The hedge can be in the form of a swap or an option. 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)/Bbl to the Company of $.72 in 2002, ($.16) in 2001 and $1.31 in 2000.

The following table summarizes the oil hedges in place as of February 14, 2003:

Crude Oil Hedges
(Based on NYMEX WTI Pricing)

Term	Barrels Per Day	Floor Sell Put	Floor Buy Put	Ceiling Sell Call	Ceiling Buy Call
04/01/2002-03/31/2003	2,500	$ -	$20.00	$24.10	$ -
04/01/2002-03/31/2003	2,500	$17.60	$21.60	$25.55	$30.00
01/01/2003-12/31/2003	1,500	$19.00	$23.00	$27.00	$30.85
04/01/2003-03/31/2004	2,500	$18.25	$22.10	$25.40	$30.10
04/01/2003-03/31/2004	2,500	$18.25	$22.10	$25.45	$30.10
04/01/2004-12/31/2004(1)	1,000	$19.00	$22.00	$25.50	$29.40
04/01/2004-12/31/2004(1)	1,000	$19.50	$23.00	$26.00	$29.75
01/01/2004-12/31/2004(1)	1,000	$19.50	$23.00	$26.00	$29.50
01/01/2004-12/31/2004(1)	1,000	$19.50	$23.00	$26.25	$29.85

(1)Hedge was put in place in 2003.

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

At December 31, 2002, approximately 94% of the Company's proved reserves, or 96 million barrels, consisted of heavy crude oil produced from depths averaging less than 2,000 feet. The Company, in achieving its goal of being a low-cost heavy oil producer, has focused on reducing its steam cost 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 on the Company's South Midway-Sunset field. The Company also owns a 42 Mw cogeneration facility, consisting of two 21 Mw turbines, which is located at the Company's Placerita field. Steam generation from these facilities is more efficient than conventional steam generators, as both steam and electricity are produced from the cogeneration facilities. In addition, the Company's ownership of these facilities allows for control over the steam supply which is crucial for the maximization of oil production and ultimate reserve recovery.

The Company believes that it may become advantageous to add additional productive steam capacity for its requirements 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 at various locations on its properties in 2001, and tested the market in 2002, the regulation and operating and financial conditions of the

electrical market in California remain in turmoil and are currently not favorable for these types of investments. The Company will continue to seek an economic long-term power sales agreement(s) to support additional cogeneration facilities.

Midway-Sunset Field

For its South Midway-Sunset properties, the Company's steam production for 2002 was generated by its 38 Mw and 18 Mw cogeneration facilities (approximately 22,500 barrels of steam per day (BSPD) including duct-fire, 13,300 in 2001 and 21,000 BSPD in 2000, respectively) and, as needed, from conventional steam generators. The Company also has a steam contract from an on-site, non-owned cogeneration facility for a minimum delivery of 2,000 BSPD for use in the Company's operations. Conventional steam generators are used by the Company as warranted to maintain current production levels, to economically produce additional crude oil and as emergency back-up steam generation to the cogeneration facilities. The Company has the capability of generating approximately 17,000 BSPD from conventional steam generators on its South Midway-Sunset properties. On its North Midway-Sunset properties, the Company relies solely on conventional steam generators for its steam requirements, which have the capability of generating approximately 3,400 BSPD.

Placerita

On its Placerita properties, the Company generated approximately 12,750 BSPD in 2002, 8,600 BSPD in 2001 and 12,500 BSPD in 2000 from its 42 Mw cogeneration facility and has the capability of generating another 11,800 BSPD from conventional steam generators.

Current Steam Output

Conventional Steam Generation

Effective December 1, 2000, the Company shut-in most of its conventional steam generation capacity due to an unprecedented increase in natural gas prices at the Southern California border (SoCal). The natural gas price for delivery into SoCal was $14.08/Million British Thermal Units (Mmbtu) in December 2000, versus an average of $2.74/Mmbtu in 1999. Historically, the SoCal natural gas price has tracked very close to the NYMEX Henry Hub (HH) price. The SoCal price increased significantly over HH in December 2000 by $7.72/Mmbtu. This dramatic rise in natural gas prices made conventional steaming operations uneconomic and, thus, forced the Company to suspend most of its conventional steaming operations. High natural gas prices in California persisted into mid-2001. In August 2001, with SoCal prices at approximately $4.00/Mmbtu, the Company began generating steam from its conventional sources. The cost of natural gas purchased averaged $3.13/Mmbtu, $5.76/Mmbtu and $4.95/Mmbtu in 2002, 2001 and 2000, respectively. The Company operated most of its conventional steam capacity in 2002 as natural gas prices moderated to achieve the Company's goal of increasing oil production to the pre-California electricity crisis levels. In early 2003, natural gas prices have increased to over $5.00/Mmbtu and the Company has selectively reduced approximately 6,000 BSPD from conventional sources to maximize operating margins.

Cogeneration Steam Generation

Going into 2001, the Company had four Standard Offer (SO) electricity sales contracts related to its three cogeneration plants. The payments under these contracts were based primarily on natural gas costs, thus, as fuel costs rose so did the electrical revenues.

The actions that California's two largest utilities (Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (Edison)) took in 2001 negatively impacted Berry and its operations. Edison failed to pay Berry for November 2000 through March 2001 power deliveries. PG&E made full payment for November 2000 and only partial payments, of approximately 15%, for December 2000 and January 2001 deliveries before filing for bankruptcy on April 6, 2001.

As a result of non-payment, the Company was forced to suspend operations at its 38 Mw and Placerita Unit II (21 Mw) cogeneration facilities effective February 1, 2001. The Company also suspended operations at its 18 Mw cogeneration facility on February 17, 2001 and on Placerita Unit I (21 Mw) cogeneration facility on April 6, 2001. The PG&E bankruptcy judge approved Berry's contract terminations with PG&E in May of 2001 and on June 14, 2001, the Company was able to restart its 38 Mw and 18 Mw cogeneration facilities by selling its electricity to a creditworthy third party and began once again injecting steam into its heavy oil reservoir at its South Midway-Sunset field.

Although Berry terminated its two contracts with Edison in early 2001, Berry and Edison agreed to reinstate the contracts under a revised pricing structure whereby Edison agreed to prepay Berry for power deliveries. One contract continued to be based on the cost of natural gas plus capacity payment while the second contract has a fixed electricity sales price of 5.37 cents/kwh plus capacity payment. Accordingly, the Company refired both 21Mw cogeneration facilities on June 27, 2001, thereby again injecting steam into its heavy oil reservoir at its Placerita field.

The Company successfully delivered its power generation in 2002 to paying customers and increased its steam generation volumes from its cogeneration facilities similar to its pre-2001 historical levels. The Company was also successful in re-instating three of its Standard Offer Contracts in late 2002 and began delivering power under these contracts to PG&E and Edison in January 2003. These contracts should result in improved electrical pricing for 2003 and are scheduled to terminate no later than December 31, 2003. Management will pursue extensions or other long-term contracts at competitive rates for 2004 and beyond. The $5.37/kwh received on the above fixed electricity contract will revert to SRAC pricing plus a capacity payment in July 2006 and the contract will expire in March 2009.

Natural Gas Deliverability

The Company has physical access to gas pipelines, such as the Kern River and Southern California Gas Company systems, to transport its gas purchases required for steam generation. The Company has no long-term gas delivery contracts and none of the Company's cogeneration facilities are subject to any long-term gas transportation agreements. Historically, there has been sufficient capacity to deliver adequate quantities of natural gas to the Company's properties, however, it appears that pipeline capacity into and within California was constrained in late 2000 and into 2001 and was at least partially responsible for higher natural gas prices in California. In early 2001, the Company subscribed to 12,000 Mmbtu/day of firm transportation for a ten-year term on the expansion project on the Kern River Pipeline. This project is expected to begin delivering gas in mid-2003. One of the benefits of owning this firm transportation is that it provides additional flexibility to the Company in securing its natural gas supply and allows the Company to potentially benefit from discounted natural gas prices in the Rockies. Another benefit is that it protects the Company from a potential recurring situation where SoCal border gas prices are significantly above Henry Hub pricing. The Company has no assurance that it can procure its future natural gas requirements at reasonable prices, however, the natural gas constraint that occurred in late 2000 and early 2001 seems to have abated and recent SoCal gas prices are similar, or slightly discounted, to Henry Hub prices.

Electricity Contracts

The following is a summary of the Company's current cogeneration electrical contracts and various operational data:

Location	Type of Contract (1)	Purchaser	Contract Expiration	Average Megawatts Delivered for sale per hour		Average barrels of steam delivered per day	
				2002	2001	2002	2001
Placerita							
Placerita I	SO2	Edison	Mar-2009	18.7	13.4	6,630	5,075
Placerita II	RSO1	Edison	Q4-2003(2)	15.4	10.1	6,124	3,707
South Midway-Sunset							
Cogen 18	RSO1	PG&E	Q4-2003(2)	10.7	7.9	6,338	3,570
Cogen 38	RSO1	PG&E	Q4-2003(2)	32.2	20.6	16,144	9,723

SO is for "Standard Offer", RSO is for "Reformed or Reinstated Standard Offer"
(2) Expected expiration

Electricity Generation

The total electricity production capacity of the Company's three cogeneration facilities is 98 Mw. 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 the steam for the enhanced oil recovery process. The Company's investments 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 companywide basis. Any profits generated from cogeneration are considered profits from electricity generation. If the expenses exceed electricity revenues, the excess expenses are charged to oil and gas operating costs.

On August 22, 2002, the California Public Utilities Commission mandated that investor owned utilities offer Standard Offer contracts to certain qualified facilities. The Company met these requirements and has entered into Revised Standard Offer (RSO1) contracts with Southern California Edison Company and Pacific Gas and Electric Company effective January 2003. These contracts should result in improved electrical pricing, which in turn will contribute to lower operating costs for the Company's crude oil production operations. These contracts will expire no later than December 31, 2003. Management will pursue extensions or other longer-term contracts at competitive rates for 2004 and beyond.

To protect a portion of the Company's electrical production from low off-peak power prices, the Company entered into fixed price sale (swap) agreements. These price protection activities resulted in a net cost/Mwh to the Company of $.38 in 2002. Following are the contracts currently in effect:

Electricity Hedges
Based on Dow Jones SP15 Index

1/1/03-3/31/03	30 MWH per off-peak hour	$ 22.50
4/1/03-5/31/03	30 MWH per off-peak hour	$ 21.00

These contracts are financial instruments and are independent of the RSO1 physical contracts.

Impact of Enron Bankruptcy

The Company had commodity derivative contracts, both oil and natural gas, in place when Enron declared bankruptcy on December 2, 2001. On December 10, 2001, the Company elected to terminate all contracts with Enron and agreed with Enron as to the value of the contracts as of termination. 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 is anticipated to be remitted upon the approval of the termination agreement in the Enron bankruptcy proceedings. The Company had a signed International Swap Dealer's Association (ISDA) master agreement with Enron which allowed for the netting of any receivables and liabilities arising thereunder.

Environmental and Other Regulations

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 our 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, 2002 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, 2002, the Company had 113 full-time employees, up from 110 full-time employees at December 31, 2001.

Oil and Gas Properties

Development

Midway-Sunset - Berry owns and operates working interests in 35 properties consisting of 3,985 acres located in the Midway-Sunset field. The Company estimates these properties account for approximately 75% of the Company's proved oil and gas reserves and approximately 70% 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 enhanced oil recovery (EOR) methods, primarily cyclic steaming.

During 2002, the primary focus at Midway-Sunset was continued development of the Formax properties acquired in 1996 and the continued application of horizontal well technology in the Monarch sands. Of the 58 wells drilled in this field in 2002, 19 were drilled on the Formax properties, and 16 were horizontal wells. The Company's objectives using this innovative technology are to improve ultimate recovery of original oil-in-place, reduce the development and operating costs of the properties and accelerate production. In 2003, the Company plans to drill an additional 67 wells in this field, including 27 on the Formax properties and 13 horizontals.

In the northern part of the Midway-Sunset field, our 2003 development plans call for the drilling of ten new wells and eight workovers to implement two steam drive pilots in a sizable diatomite accumulation. This 2003 program follows an encouraging corehole that the Company drilled in 2002, indicating both good oil saturation and rock properties. Ultimate completion of this program is dependent on the results of the 2003 pilots.

Placerita - The Placerita property consists of six leases (three federal) and three fee properties totaling approximately 750 acres. The Company estimates current reserves from Placerita account for approximately 20% of Berry's proved oil and gas reserves and approximately 19% of Berry's daily production. The average depth of these wells is 1,800 feet and the properties rely extensively on thermal recovery methods, primarily steam flooding.

During 2002, the Company drilled eight development wells at Placerita to install Phase One of a major development campaign at the north end of the field. Included in the Company's 2003 development plan is the continuation of the north end development with ten steamflood producers and six major workovers.

Montalvo - Berry owns a 100% working interest in six leases, totaling 8,563 acres, in Ventura County, California 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 5% of Berry's daily production. The wells produce from an average depth of approximately 11,500 feet. No new wells were drilled in 2002, however three successful major workovers were done. There are no plans at this time to drill any new wells in 2003, however two idle wells are scheduled to be returned to production.

South Joe Creek - In April 2001, Berry purchased a 15.83% non-operated working interest in the South Joe Creek coalbed methane field which represented interests in federal, state and local leases totaling approximately 5,800 acres in the Campbell County portion of the Powder River Basin in Wyoming. The property has 85 wells (13 net). Six additional wells (1 net) were drilled in 2002 and another 18 wells (3 net) are planned for drilling and completion in 2003. At year-end, the production rate was 15 million cubic feet of gas (2.4 net) per day.

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 gas production and reserves from known coalbeds (the leased acreage indicated is as of February 14, 2003). The Company drilled a five-spot production pilot in each state late in 2002 and both are currently in the early dewatering stage. As such, the Company has no recorded reserves in either state at December 31, 2002. The Company is currently evaluating the location and method of drilling additional test wells in Kansas.

The following is a summary of the Company's capital expenditures incurred during 2002 and 2001 and projected capital expenditures for 2003. It should be noted that the Company had projected 2002 capital expenditures of $19.6 million. The capital expenditure budget for 2002 was significantly revised upward as oil prices rose.

CAPITAL EXPENDITURES SUMMARY
(in thousands)

	2003(1)	2002	2001

(Projected)

Midway-Sunset Field			
New wells	$ 12,160	$ 10,224	$ 4,799
Remedials/workovers	1,365	1,981	1,367
Facilities	4,050	2,238	4,069
	17,575	14,443	10,235
Placerita			
New wells	5,000	5,278	782
Remedials/workovers	545	174	465
Facilities	1,180	6,862	1,660
	6,725	12,314	2,907
Montalvo			
Remedials/workovers	450	909	674
Facilities	590	179	331
	1,040	1,088	1,005
South Joe Creek (2)			
New wells	396	355	593
Facilities	50	216	79
	446	571	672
Kansas and Illinois(CBM)(3)			
New wells	780	1,185	-
Facilities	555	47	-
	1,335	1,232	-
Other	499	984	76
Totals	$ 27,620	$ 30,632	$ 14,895

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

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

Exploration

The Company considers its pilot wells in both Kansas and Illinois to be exploratory in nature as there is not proven production near those areas. However, these are 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 exploration 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 drive 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 for only 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 estimate the proved oil and gas reserves and the future net revenues to be derived from properties of the Company for the year ended December 31, 2002. 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, 2002. For the Company's operated properties, these 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:

	2002	2001	2000
Net annual production:(1)			
Oil (Mbbls)	5,123	4,996	5,434
Gas (Mmcf)	769	288	199
Total equivalent barrels(2)	5,251	5,044	5,467
Average sales price:			
Oil (per Bbl)	$ 19.54	$ 19.70	$ 21.70
Gas (per mcf)	2.22	5.09	4.34
Per BOE	19.39	19.79	21.72
Average operating cost - oil and gas production (per BOE)(3)	8.49	7.99	8.20

(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 $1.72, $1.31 and $0.53 for 2002, 2001 and 2000, respectively. See Note 2 to the financial statements.

Acreage and Wells

At December 31, 2002, the Company's properties accounted for the following developed and undeveloped acres:

	Developed Acres		Undeveloped Acres		Total	
	Gross	Net	Gross	Net	Gross	Net
California	7,226	7,226	7,244	7,244	14,470	14,470
Kansas	-	-	190,645	190,645	190,645	190,645
Illinois	-	-	52,138	52,138	52,138	52,138
Other	3,720	573	1,746	277	5,466	850
	10,946	7,799	251,773	250,304	262,719	258,103

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 2,520 gross oil wells (2,498 net) and 104 gross gas wells (25 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:

	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells drilled:						
Productive(in testing)	11	11	-	-	-	-
Dry(1)	-	-	-	-	-	-
Development wells drilled:(2)						
Productive	81	76	103	47	81	81
Dry(1)	-	-	1	-	-	-
Total wells drilled:						
Productive	92	87	103	47	81	81
Dry(1)	-	-	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.
(2) Wells drilled include 6 wells gross, 1 well net for 2002 and 67 wells gross, 11 wells net for 2001 that were drilled at South Joe Creek which the Company holds a 15.83% working interest.

On December 31, 2002, there were no wells being drilled by the Company. The 2003 drilling activity commenced in February 2003.

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, 2002) 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 executive officer and members of the Board of Directors.

JERRY V. HOFFMAN, 53, 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.

RALPH J. GOEHRING, 46, 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, 42, 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, 36, joined the Company effective February 1, 2002 as the Vice President of Corporate Development. Mr. Duginski has a mechanical engineering background and was previously with Texaco, Inc. from 1988 to 2002 where he was most recently responsible for new business development and gas and power operations.

BRIAN L. REHKOPF, 55, 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, 56, has been Controller since December 1985.

KENNETH A. OLSON, 47, 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.

In conjunction with the acquisition of the Tannehill assets in 1996, the Company issued a Warrant Certificate to the beneficial owners of Tannehill Oil Company. This Warrant authorized the purchase of 100,000 shares of Berry Petroleum Company Class A Common Stock until November 8, 2003 at $14.06 per share. The Warrant was purchased from the holders in 2002 and was subsequently canceled.

Berry's Class A Common Stock is listed on the New York Stock Exchange under the symbol "BRY." The Class B Stock is not publicly traded. The market data and dividends for 2002 and 2001 are shown below:

	2002 Price Range High	2002 Price Range Low	2002 Dividends Per Share	2001 Price Range High	2001 Price Range Low	2001 Dividends per Share
First Quarter	$ 16.90	$ 13.25	$.10	$ 14.75	$ 12.05	$.10
Second Quarter	17.58	15.45	.10	15.05	11.00	.10
Third Quarter	18.25	14.52	.10	16.99	13.65	.10
Fourth Quarter	17.50	15.60	.10	17.75	14.26	.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 14, 2003, December 31, 2002 and December 31, 2001 was $15.60, $17.05 and $15.70, respectively.

The number of holders of record of the Company's Common Stock was 725 (and approximately 3,600 street name shareholders) as of February 14, 2003. There was one Class B Stockholder of record as of February 14, 2003.

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.

Since Berry Petroleum Company's formation in 1985 through December 31, 2002, the Company has paid dividends on its Common Stock for 53 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.

At December 31, 2002, 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, 2002 were derived from the audited financial statements and the accompanying notes to those financial statements (in thousands, except per share, per BOE and % data):

	2002	2001	2000	1999	1998
Statement of Operations Data:					
Sales of oil and gas	$ 102,026	$ 100,146	$ 118,801	$ 66,615	$ 39,858
Sales of electricity	28,827	35,917	52,765	33,731	15,680
Operating costs - oil and gas production	44,604	40,281	44,837	27,829	18,272
Operating costs - electricity generation	28,496	35,506	50,566	27,930	15,236
General and administrative expenses (G&A)	7,928	7,174	7,754	6,269	3,975
Depreciation, depletion & amortization (DD&A)	16,452	16,520	14,030	12,294	10,080
Net income	30,024	21,938	37,183	18,006	3,879
Basic net income per share	1.38	1.00	1.69	.82	.18
Weighted average number of shares outstanding	21,741	21,973	22,029	22,010	22,007

Balance Sheet Data:					
Working capital	$ (3,689)	$ 5,837	$ (1,154)	$ 8,435	$ 9,081
Total assets	258,073	237,973	238,359	207,649	173,804
Long-term debt	15,000	25,000	25,000	52,000	30,000
Shareholders' equity	172,058	153,153	145,224	116,213	106,924
Cash dividends per share	.40	.40	.40	.40	.40
Operating Data:					
Cash flow from operations	57,895	35,433	65,934	24,809	19,924
Capital expenditures (excluding acquisitions)	30,632	14,895	25,253	9,122	6,981
Property/facility acquisitions	5,880	2,273	3,182	33,605	2,991
Oil and gas producing operations (per BOE):					
Average sales price	$ 19.39	$ 19.79	$ 21.72	$ 13.07	$ 9.05
Average operating costs(1)	8.49	7.99	8.20	5.47	4.15
G&A	1.51	1.42	1.42	1.23	.90
Cash flow	9.39	10.38	12.10	6.37	4.00
DD&A	3.13	3.28	2.57	2.42	2.29
Operating income less G&A	$ 6.26	$ 7.10	$ 9.53	$ 3.95	$ 1.71
Production (BOE)	5,251	5,044	5,467	5,090	4,399
Production (Mwh)	748	483	764	728	448
Proved Reserves Information:					
Total BOE	101,719	102,855	107,361	112,541	92,609
Present value (PV10) of estimated future cash flow before income taxes	$602,157	$356,556	$721,770	$714,555	$113,811
Year-end average BOE price for PV10 purposes	24.91	14.13	21.13	19.37	7.09
Other:					
Return on average shareholders' equity	18.5%	14.7%	28.5%	16.5%	3.5%
Return on average total assets	12.5%	8.7%	16.8%	9.0%	2.2%
Total debt/total debt plus equity	8.0%	14.0%	14.7%	30.9%	21.9%
Year-end stock price	$ 17.05	$ 15.70	$ 13.375	$ 15.125	$ 14.188
Year-end market capitalization	$370,865	$341,192	$294,699	$332,920	$312,247
(1) Including monthly expenses in excess of monthly revenues from cogeneration operations	$ 1.72	$ 1.31	$ 0.53	$ -	$ 0.14

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, 2002, 2001and 2000 and the financial condition, liquidity and capital resources as of December 31, 2002 and 2001. 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.

Results of Operations

The Company earned $30 million, or $1.38 per share, in 2002 on revenues of $132.5 million, up 37% from $21.9 million, or $1.00 per share, on revenues of $138.5 million in 2001, but were 19% lower than $37.2 million, or $1.69 per share, on revenues of $172.0 million earned in 2000, Berry's most profitable year. The increase in income in 2002 versus 2001 was due to higher production, lower interest expense and the recovery of $3.6 million, which represented a portion of electricity receivables written off in 2001, partially offset by higher operating costs.

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

	2002	2001	2000
Oil and Gas			
Net production - BOE/D	14,387	13,820	14,937
Per BOE:			
Average sales price	$19.39	$19.79	$21.72
Operating costs(1)	7.94	7.50	7.77
Production taxes	.55	.49	.43
Total operating costs	8.49	7.99	8.20
DD&A	3.13	3.28	2.57
G&A	1.51	1.42	1.42
Interest expense	.20	.74	.58
Electricity			
Electric power produced - Megawatt (Mw) hrs/day	2,050	1,325	2,088
Electric power sold - Megawatt (Mw) hrs/day	1,848	1,245	1,979
Average sales price/Mw	$40.06	$79.14	$72.26
Fuel gas cost/Mmbtu	3.13	5.76	4.95

(1) Including monthly expenses in excess of monthly revenues from cogeneration operations of $1.72, $1.31 and $.53 in 2002, 2001 and 2000, respectively.

BOE/D = Barrels of oil equivalent per day

Operating income from oil and gas operations was $41.3 million in 2002, down from $42.2 million in 2001, and $60.3 million in 2000. The decrease from 2001 was due primarily to higher operating costs, partially offset by higher production.

Oil and gas production (BOE/D) for 2002 was 14,387, 4% higher than 13,820 in 2001, but 4% lower than 14,937 in 2000. Production volumes declined dramatically in 2001, reaching a low of approximately 12,800 BOE/D in mid-2001 due to the curtailment of steaming operations early in 2001 as a result of the California electricity crisis. Steaming operations were re-established by August of 2001 and the Company exited 2001 with a production level of approximately 13,500 BOE/D. Steam injection rates of 54,000 to 64,000 barrels of steam per day were maintained for all of 2002. This effort combined with the effects of the 2002 drilling program resulted in production rate improvement throughout the year with an exit rate of approximately 15,700 barrels per day for December 2002. The Company plans to continue with significant drilling and development projects in 2003 with a goal of averaging 16,400 BOE/D in 2003 and exiting this year at 17,700 BOE/D.

The 2002 average sales price/BOE for the Company's crude oil was $19.39, down 2% from $19.79 in 2001 and 10% from $21.72 in 2000. Posted oil prices for the Company's 13 degree heavy crude oil began the year at $13.08 and escalated steadily to $25.50 at December 31, 2002 and have escalated further since year-end to a price of $30.75 on February 14, 2003. Over 90% of the Company's crude oil has been contracted with a single customer until December 31, 2005 and is sold at prices based upon the higher of the average local field posted prices plus a fixed bonus, or WTI minus a fixed differential.

From time to time, the Company enters into crude oil 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. The hedge can be in the form of a swap or an option. 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. Additionally, the Company utilizes more than one counterparty on its hedges and monitors each counterparty's credit rating. The Company's current hedging program is designed to hedge approximately 40% to 45% of its net production while retaining some upside on the hedged barrels in the event of a major price increase. These price protection activities resulted in a net cost (benefit)/Bbl to the Company of $.72, ($.16) and $1.31 in 2002, 2001 and 2000, respectively.

Electricity prices relative to the cost of natural gas to generate such electricity in 2002 were very weak for the entire year. The Company produced approximately 67% of its power for sale on the open market and received an average of $26.95/Mwh for that portion of total electricity sales and $40.06 per Mwh overall. In January 2003, Berry began delivery of electricity under three reformed or reinstated Standard Offer contracts with Pacific Gas and Electric Company and Southern California Edison Company, which should result in improved electrical pricing and contribute to lower operating costs for the Company's crude oil production operations during 2003. These contracts are scheduled to terminate no later than December 31, 2003. Management will pursue extensions or other longer-term contracts at competitive rates for 2004 and beyond. Berry's fourth contract, which is based on a fixed electricity sales price until July 31, 2006 and then a short-run avoided cost formula, expires in March 2009.

To protect a portion of the Company's electrical production from low off-peak power prices, the Company entered into fixed price sale (swap) agreements on 30 Mw of off-peak power from October 2002 through May of 2003 at prices ranging from $21.00 to $22.50 /Mwh.

Operating costs in 2002 were $44.6 million, or $8.49 per BOE, up from $40.3 million in 2001, or $7.99 per BOE and comparable to $44.8 million in 2000, or $8.20 per BOE. The primary reason for the increase from 2001 was higher steam costs. Steam costs increased due to higher volumes of steam from conventional generators, weak electricity prices at the Company's cogeneration facilities and the suspension of steaming for a portion of 2001. In addition to higher steam costs, well work increased by $.8 million in 2002 due to the higher steaming activity and increased efforts to bring more marginal producers on line to capture revenue from improving oil prices. In early 2003, natural gas prices increased to over $5.00/Mmbtu and the Company has selectively reduced steam injection approximately 6,000 BSPD. Management anticipates that operating costs will increase to an average of approximately $8.50 to $9.50 per BOE for 2003.

DD&A in 2002 was $16.5 million, or $3.13 per BOE, equivalent to $16.5 million, or $3.28 per BOE in 2001, but higher than $14.0 million, or $2.57 per BOE, in 2000. The increase from 2000 was primarily related to a higher asset base due to the cumulative effect of development activity in recent years. The Company is projecting DD&A in 2003, on a BOE basis, to be approximately $3.00 to $3.10 per BOE.

G&A expenses in 2002 were $7.9 million, or $1.51 per BOE, up 6% and 1% from $7.2 million, or $1.42 per BOE, in 2001 and $7.8 million, or $1.42 per BOE, in 2000. The increase from 2001 was primarily related to higher costs to evaluate potential acquisitions and rental and other costs associated with the Company's Bakersfield headquarters office. The Company is targeting G&A of approximately $1.50 per BOE in 2003.

Interest expense in 2002 decreased to $1.0 million, or $.20 per BOE, from $3.7 million, or $.74 per BOE, in 2001. Early in 2001, the Company drew down its line of credit to compensate for large unpaid receivables from electricity sales in late 2000 and early 2001. Later in 2001 and early in 2002, most of the receivables were recovered and long-term debt was reduced from a peak of $70 million to $25 million at December 31, 2001. Long-term debt was further reduced in 2002 through internally generated funds to a balance of $15 million at December 31, 2002.

The Company experienced an effective tax rate of 20% in 2002, up slightly from the 19% reported in 2001, but down from 28% reported in 2000. The low effective tax rate is primarily a result of significant enhanced oil recovery (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 volumes. This is the fifth 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 well below the statutory rate in 2003.

In 2002, Berry adopted SFAS No. 143, `Accounting for Asset Retirement Obligations.' The Company has recorded the estimate costs for the ultimate abandonment of its wells and facilities for many years under SFAS No. 19 and the effect of the change on 2002 net income was immaterial. The effect on net income in 2003 under the newly adopted method will be a pre-tax charge of approximately $.5 million compared to a pre-tax charge of approximately $.8 million under the previous method. The most significant effect of the change was to move the current accumulated financial obligation to a long-term liability account. The value of this obligation under our previous method had been recorded as a reduction to the total book value of the Company's property, plant and equipment. The accrued abandonment obligation at December 31, 2002 was $4.6 million. The recorded abandonment obligation at December 31, 2001 under the previous method of $5.4 million was reclassified to a long-term liability in the current year presentation for comparability purposes.

Financial Condition, Liquidity and Capital Resources

Working capital at December 31, 2002 was negative ($3.7) million, down from $5.8 million at December 31, 2001 and negative ($1.2) million at December 31, 2000. Net cash provided by operations in 2002 was $57.9 million, up 64% from $35.4 million in 2001, but 14% lower than $65.9 million in 2000. Cash generated was used to fund $30.6 million in capital expenditures, $5.9 million in leasehold acquisitions, pay dividends of $8.7 million and reduce long-term debt by $10 million.

Total capital expenditures incurred excluding acquisitions in 2002 were $30.6 million, up 105% from $14.9 million in 2001. Included in this year's projects was the drilling of 87 wells, 16 of which were horizontal and the completion of 69 workovers. The Company also made facility improvements totaling $9.6 million on its producing assets. These projects were responsible for a large portion of the production gains made in 2002 and should continue to contribute to production increases in 2003 and beyond.

The Company also acquired acreage in Kansas and Illinois in 2002 for the purpose of exploring for economic concentrations of coalbed methane. At December 31, 2002, approximately 191,000 acres in Kansas and 52,000 acres in Illinois were leased at a cost of approximately $5.9 million. In 2002, the Company drilled 4 producing and one water disposal well and one well was returned to production on a pilot in Illinois and 5 producing wells and 1 water disposal well were drilled in another pilot in Kansas. Additional wells may be completed in Kansas in 2003. The evaluation of these projects is expected to continue through most of 2003.

The Company has continued to maintain its $150 million revolving bank facility with approximately $130 million available for potential acquisitions or other purposes at December 31, 2002.

The Company has budgeted $27.6 million, excluding property acquisitions, in capital projects for 2003. This program, on a net well basis, consists of 101 net vertical wells, 13 horizontal producers and 49 workovers. In addition to drilling and workover activities, $6.4 million in facilities are scheduled for completion on the Company's core properties. One of the focuses of the 2003 budget is to continue to develop the proved but undeveloped reserves from the Company's Placerita properties.

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. In 2002, there were no additional shares repurchased under this program, however, the Company did purchase and cancel an outstanding warrant for 100,000 shares.

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 2002.

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 for income taxes, which may include various tax planning strategies, in determining taxable income, 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 periodically and accrued the estimated obligation monthly based on SFAS No. 19, prior to adoption of SFAS No. 143, as described in `Recent Accounting Developments' below. The implementation of this standard had an immaterial impact on the financial statements of the Company.

Recent Accounting Developments

In August 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This Statement requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. All provisions of this Statement will be effective at the beginning of fiscal 2003. However, as allowed, the Company opted to implement this standard in 2002. See Note 13 to the Financial Statements.

In October 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." This Statement supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of" and amends APB No. 30, "Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions." This Statement

requires that long-lived assets that are to be disposed of by sale be measured at the lower of book value or fair value less costs to sell. SFAS No. 144 retains the fundamental provisions of SFAS 121 for (a) recognition and measurement of the impairment of long-lived assets to be held and used and (b) measurement of long-lived assets to be disposed of by sale. This Statement also retains APB No. 30's requirement that companies report discontinued operations separately from continuing operations. All provisions of this Statement were effective in the first quarter of 2002 and its implementation had no material impact on the financial statements taken as a whole.

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 continues to record compensation related to employee stock options based on the intrinsic value method per 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. Among other things, the Company is concerned about the reasonableness of the values of its stock options determined using the Black Scholes method. Therefore, the Company has delayed the potential transition to recording stock compensation based on fair market value until there is more clarity regarding the measurement of stock option values.

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 has significant market risk exposure related to the prices received for the sale of its crude oil. A $1 change in oil price will equate to an approximate $5.7 million change in annual revenues. The Company periodically enters into hedge contracts to manage the oil price risk. In 2002, the Company entered into a number of hedges, based on WTI pricing, on 6,500 barrels per day, or approximately 42% of total production. The hedges have a floor ranging from $21.60 to $23.00, whereby the Company will receive $3.85 to $4.00 below these prices. They also have ceilings ranging from $24.10 to $27.00, whereby the Company will give up $3.85 to $4.70 above these prices. Additionally, the Company utilizes more than one counterparty on these hedges and monitors each counterparty's credit rating.

The Company is also at risk for a widening of the differential between the WTI crude oil price and the posted price of the Company's heavy crude oil. To minimize this risk, the Company has a sales contract in place through 2005 where more than 90% of its crude oil production is priced at the higher of local field posting plus a bonus, or WTI minus a fixed differential.

The Company also has market risk exposure related to the price received for the sale of its electricity production and the cost paid by the Company for the natural gas used in its cogeneration operations. The Company's three cogeneration facilities, when combined, have electricity production capacity of 98 Mw of electricity/hour (Mwh). Of this total, the Company sells approximately 92 Mwh and the remaining 6 Mwh is consumed in the Company's operations. The Company's goal is to control its "spark spread" (the difference between the sales price received for its electricity and the cost to purchase natural gas used as fuel in the cogeneration operations). The Company consumes approximately 27,000 Mmbtu/day of natural gas as fuel in these facilities. A change of $.10/Mmbtu in the cost of natural gas used in the cogeneration facilities equates to a change of approximately $1.0 million in operating costs. The Company has a long-term electricity sales contract in place through July 31, 2006 at a fixed price of $53.70/Mwh plus capacity on approximately 19 Mwh of electricity production with a major utility. A change of $1/Mwh in the price received for electricity on the remaining 73 Mwh equates to approximately $6 million in annual revenues. During 2002, the majority of the remaining electricity was sold on the open market to a creditworthy customer. To protect a portion of the Company's electrical production from low off-peak power prices, the Company entered into a series of fixed price (swap) agreements on 30 Mwh of off-peak hour electricity. At December 31, 2002, the Company has swap agreements in place through May 31, 2003 at prices ranging from $21.00 to $22.50 per Mwh. In January 2003, the Company entered into three reformed or reinstated Standard Offer contracts with PG&E and SCE which should result in improved electrical pricing in 2003. These contracts will expire no later than December 31, 2003. The Company is pursuing longer-term arrangements on the sale of electricity and may enter into hedges on its natural gas purchases to seek to improve the spark spread in 2003 and beyond.

The Company also consumes up to an additional 10,000 Mmbtu/day of additional natural gas as fuel in its conventional generators, which are used to supplement the Company's steam requirements. A change of $.10 in the cost of this natural gas requirement equates to a change of approximately $.4 million in operating costs. The Company may enter into hedges on natural gas purchases to help control this cost or shut-in the conventional generators if deemed appropriate.

Related to its natural gas purchases, the Company is also exposed to the volatility in the differential between gas prices at the Southern California border and Henry Hub delivery points. To help minimize the risk, the Company entered into a 12,000 Mmbtu/day firm transportation agreement on the Kern River pipeline expansion with gas deliveries to commence in mid-2003. This agreement 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. This is a take-or-pay contract and the Company is required to pay approximately $.71/Mmbtu if the Company does not take delivery of gas volumes under the agreement.

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 risks, litigation uncertainties, drilling, development and operating risks, 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
Index to Financial Statements and Supplementary Data

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 ACCOUNTANTS

To the Shareholders and Board of Directors
Berry Petroleum Company

In our opinion, the accompanying balance sheets and the related statements of operations and comprehensive income, shareholders' equity and cash flows present fairly, in all material respects, the financial position of Berry Petroleum Company (the "Company")at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

s/s PricewaterhouseCoopers LLP
Los Angeles, California
February 12, 2003

BERRY PETROLEUM COMPANY
Balance Sheets
December 31, 2002 and 2001
(In Thousands, Except Share Information)

	2002	2001
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9,866	$ 7,238
Short-term investments available for sale	660	594
Accounts receivable	15,582	17,577
Prepaid expenses and other	2,597	2,792
	--------	--------

Total current assets	28,705	28,201
Oil and gas properties (successful efforts basis), buildings and equipment, net	228,475	208,860
Other assets	893	912
	--------	--------
	$ 258,073	$ 237,973
	========	========
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 19,189	$ 11,197
Accrued liabilities	6,470	7,089
Federal and state income taxes payable	2,612	4,078
Fair value of derivatives	4,123	-
	--------	--------
Total current liabilities	32,394	22,364
Long term liabilities:		
Deferred income taxes	33,866	32,009
Long-term debt	15,000	25,000
Abandonment obligation	4,596	5,447
Fair value of derivatives	159	-
	--------	--------
	53,621	62,456
Commitments and contingencies (Notes 9 and 10)	-	-
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;		
20,852,695 shares issued and outstanding (20,833,094 in 2001)	209	208
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	49,052	48,905
Accumulated other comprehensive loss	(2,569)	-
Retained earnings	125,357	104,031
	--------	--------
Total shareholders' equity	172,058	153,153
	--------	--------
	$ 258,073	$ 237,973
	========	========

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

BERRY PETROLEUM COMPANY
Statements of Income
Years ended December 31, 2002, 2001 and 2000
(In Thousands, Except Per Share Data)

	2002	2001	2000
Revenues:			
Sales of oil and gas	$ 102,026	$ 100,146	$ 118,801
Sales of electricity	28,827	35,917	52,765
Interest and dividend income	536	2,150	447
Other income	1,116	328	36
	--------	--------	--------
	132,505	138,541	172,049
Expenses:	--------	--------	--------
Operating costs - oil and gas production	44,604	40,281	44,837
Operating costs - electricity generation	28,496	35,506	50,566
Depreciation, depletion & amortization	16,452	16,520	14,030
General and administrative	7,928	7,174	7,754
Interest	1,042	3,719	3,186
(Recovery) write-off of electricity receivable	(3,631)	6,645	-

Loss on termination of derivative contracts	-	1,458	-
	94,891	111,303	120,373
Income before income taxes	37,614	27,238	51,676
Provision for income taxes	7,590	5,300	14,493
Net income	$ 30,024	$ 21,938	$ 37,183
Basic net income per share	$ 1.38	$ 1.00	$ 1.69
Diluted net income per share	$ 1.37	$ .99	$ 1.67
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)	21,741	21,973	22,029
Effect of dilutive securities:			
Stock options	156	113	185
Other	42	24	26
Weighted average number of shares of capital stock used to calculate diluted net income per share	21,939	22,110	22,240

Statements of Comprehensive Income
Years Ended December 31, 2002, 2001 and 2000
(In Thousands)

	2002	2001	2000
Net income	$ 30,024	$ 21,938	$ 37,183
Unrealized gains (losses) on derivatives, net of income taxes of $1,713, $0 and $294, respectively	(2,569)	-	441
Reclassification of unrealized gains included in net income	-	(441)	-
Comprehensive income	$ 27,455	$ 21,497	$ 37,624

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

BERRY PETROLEUM COMPANY
Statements of Shareholders' Equity
Years Ended December 31, 2002, 2001 and 2000
(In Thousands, Except Per Share Data)

	Class A	Class B	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (loss)	Shareholders' Equity
Balances at January 1, 2000	$ 211	$ 9	$ 53,487	$ 62,506	$ -	$ 116,213
Stock options exercised	-	-	90	-	-	90
Deferred director fees-stock compensation	-	-	109	-	-	109
Cash dividends declared-$.40 per share	-	-	-	(8,812)	-	(8,812)
Unrealized gains on derivatives	-	-	-	-	441	441
Net income	-	-	-	37,183	-	37,183
Balances at December 31, 2000	211	9	53,686	90,877	441	145,224

Stock options exercised	-	-	172	-	-	172
Deferred director fees- stock compensation	-	-	156	-	-	156
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	-	-	-	21,938	-	21,938
Balances at December 31, 2001	208	9	48,905	104,031	-	153,153
Stock options exercised	1	-	57	-	-	58
Deferred director fees stock compensation	-	-	190	-	-	190
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	-	-	-	30,024	-	30,024
Balances at December 31, 2002	$ 209	$ 9	$ 49,052	$125,357	$(2,569)	$ 172,058

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

BERRY PETROLEUM COMPANY
Statements of Cash Flows
Years Ended December 31, 2002, 2001 and 2000
(In Thousands)

	2002	2001	2000
Cash flows from operating activities:			
Net income	$ 30,024	$ 21,938	$ 37,183
Depreciation, depletion and amortization	16,452	16,520	14,030
Increase (decrease) in deferred income tax liability	1,857	(50)	3,147
Other, net	(184)	(505)	249
Net working capital provided by operating activities	48,149	37,903	54,609
Decrease (increase) in current assets other than cash, cash equivalents and short-term investments	3,839	11,241	(14,227)
Increase (decrease) in current liabilities other than notes payable	5,907	(13,711)	25,552
Net cash provided by operating activities	57,895	35,433	65,934
Cash flows from investing activities:			
Capital expenditures, excluding property acquisitions	(30,632)	(14,895)	(25,253)
Property acquisitions	(5,880)	(2,273)	(3,182)
Purchase of short-term investments	(660)	(1,183)	(584)
Maturities of short-term investments	594	1,171	600
Other, net	52	151	49
Net cash used in investing activities	(36,526)	(17,029)	(28,370)
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	5,000	45,000	1,000
Payment of long-term debt	(15,000)	(45,000)	(28,000)
Dividends paid	(8,698)	(8,784)	(8,812)
Share repurchase program	-	(5,112)	-
Other, net	(43)	(1)	(1)
Net cash used in financing activities	(18,741)	(13,897)	(35,813)
Net increase in cash and cash equivalents	2,628	4,507	1,751
Cash and cash equivalents at beginning of year	7,238	2,731	980

Cash and cash equivalents at end of year	$ 9,866	$ 7,238	$ 2,731
Supplemental disclosures of cash flow information:			
Interest paid	$ 1,321	$ 3,532	$ 2,999
Income taxes paid	$ 5,420	$ 5,635	$ 9,712
Supplemental non-cash activity:			
Decrease in fair value of derivatives:			
Current (net of income taxes of $1,649)	$ 2,474	$ -	$ -
Non-current (net of income taxes of $63)	95	-	-
Net decrease to accumulated other comprehensive income	$ 2,569	$ -	$ -

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

BERRY PETROLEUM COMPANY
Notes to the 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. Substantially all of the Company's oil and gas reserves are located in California. Approximately 97% of the Company's production 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 generate electricity for sale.

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

2. Summary of Significant Accounting Policies

Cash and cash equivalents

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

Short-term investments

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. Such investments are stated at cost, which approximates market. The Company utilizes specific identification in computing realized gains and losses on investments sold.

Oil and gas properties, buildings and equipment

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 exploration plays, the drilling costs may be capitalized for up to a year before 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.

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. 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 with an offsetting abandonment liability. The capitalized abandonment costs are amortized using the units-of-production method. The Company increases the liability monthly by recording accretion expense using the Company's credit adjusted interest rate. 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.

Summary of Significant Accounting Policies (cont'd)

Environmental Expenditures

The Company reviews, on a quarterly basis, its estimates of costs of compliance with environmental laws and 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

From time to time, the Company utilizes options, swaps and collars (derivative instruments) to manage its commodity price risk. On October 1, 2000, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," which established new accounting and reporting requirements for derivative instruments and hedging activities. SFAS No. 133, as amended by SFAS No. 138, 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.

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 recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. 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 catergories were $1.4 million, $1.2 million and $1.6 million for 2002, 2001 and 2000, respectively.

Summary of Significant Accounting Policies (cont'd)

Stock-Based Compensation

As allowed in SFAS No. 123, "Accounting for Stock-Based Compensation," the Company continues to apply Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees," and related interpretations in recording compensation related to its plan. The supplemental disclosure requirements of SFAS No. 123, as amended in SFAS No. 148, "Accounting for Stock-Based Compensation - Transaction and Disclosure," related to the Company's stock option plan is presented below:

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:

	2002	2001	2000
Yield	2.55%	2.72%	2.77%
Expected option life - years	7.5	7.5	4.5
Volatility	33.45%	38.71%	36.53%
Risk-free interest rate	4.09%	4.65%	4.85%

Had compensation cost for the Company's stock based compensation plan (see Note 11) been based upon the fair value at the grant dates for awards under the plan consistent with the method of 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 proforma amounts indicated below (in thousand, except per share data):

	2002	2001	2000
Compensation cost, net of income taxes:			
As reported	$ 33	$ 92	$ 332

Pro forma	726	678	767
Net income:			
As reported	30,024	21,938	37,183
Pro forma	29,331	21,352	36,748
Basic net income per share:			
As reported	1.38	1.00	1.69
Pro forma	1.35	.97	1.67
Diluted net income per share:			
As reported	1.37	.99	1.67
Pro forma	1.34	.97	1.65

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 basis 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.

Summary of Significant Accounting Policies (cont'd)

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 common shares outstanding (the denominator). 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 August 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This Statement requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. All provisions of this Statement will be effective at the beginning of fiscal 2003 but earlier implementation was encouraged by the FASB and, therefore, the Company implemented this standard in 2002. See Note 13.

In October 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." This Statement supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of" and amends APB No. 30, "Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions." This Statement requires that long-lived assets that are to be disposed of by sale be measured at the lower of book value or fair value less costs to sell. SFAS No. 144 retains the fundamental provisions of SFAS 121 for (a) recognition and measurement of the impairment of long-lived assets to be held and used and (b) measurement of long-lived assets to be disposed of by sale. This Statement also retains APB No. 30's requirement that companies report discontinued operations separately from continuing operations. All provisions of this Statement became effective in the first quarter of 2002 and its implementation had an immaterial impact on the financial statements taken as a whole.

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 continues to record compensation related to employee stock options based on the intrinsic value method per APB 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. Among other things, the Company is concerned about the reasonableness of the market values determined using the Black Scholes method. Therefore, the Company has delayed the potential transition to recording stock compensation based on fair market value until there is more clarity regarding the measurement of stock option values.

Reclassifications

Certain reclassifications have been made to the 2001 and 2000 financial statements to conform with the 2002 presentation.

3. Fair Value of Financial Instruments

The carrying amounts of cash and short-term investments are not materially different from their fair values because of the short maturity of those instruments. Cash equivalents consist principally of commercial paper investments. Cash equivalents of $9.8 million and $6.4 million at December 31, 2002 and 2001, respectively, are stated at cost, which approximates market.

The Company's short-term investments available for sale at December 31, 2002 and 2001 consist of United States treasury notes that mature in less than one year. The carrying value of the Company's long-term debt is assumed to

3. Fair Value of Financial Instruments (cont'd)

approximate its fair value since it is carried at current interest rates. For the three years ended December 31, 2002, 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.

In 2001, the Company established an oil price hedge on 3,000 Bbl/day for a one-year period beginning on June 1; and a natural gas price hedge on 5,000 Mmbtu/day 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 termination. 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 is anticipated to be remitted upon the approval of the termination agreement in the Enron bankruptcy proceedings. The Company had a signed International Swap Dealer's Association (ISDA) 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 entered into hedge contracts in 2000 and 2002 covering 3,000 BPD to 6,500 BPD of its crude oil production. The Company recorded losses of $3.8 million, $0 and $7.1 million in 2002, 2001 and 2000, respectively, which were reported in "Sales of oil and gas" in the Company's financial statements.

To protect a portion of the Company's electrical production from low off-peak power prices, the Company entered into a series of fixed price sale (swap) agreements on 30 Mwh per off-peak hours which cover October 2002 through May 2003. In 2002, the Company incurred losses of $.3 million which were recorded in

"Sales of electricity" 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. 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 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 bonus, 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, 2002, 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 Company (SCE) 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 SCE plus interest resulting in pre-tax income of $4.2 million recorded in the first quarter of 2002 due to this collection.

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, 2002, 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.

4. Concentration of Credit Risks (cont'd)

The following summarizes the accounts receivable balances at December 31, 2002 and 2001 and sales activity with significant customers for each of the years ended December 31, 2002, 2001 and 2000 (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.

Customer	Accounts Receivable December 31, 2002	Accounts Receivable December 31, 2001	Sales For the Year Ended December 31, 2002	2001	2000
Oil & Gas Sales:					
A	$ 10,714	$ 4,754	$ 94,870	$ 83,336	$ 87,613
B	-	870	10,188	14,962	18,000
C	621	260	5,463	4,858	5,499
D	-	5	-	157	12,390
E	-	-	-	-	13,080
	$ 11,335	$ 5,889	$ 110,521	$ 103,313	$ 136,582
Electricity					

Sales:					
F	$ 1,795	$ 9,873	$ 15,199	$ 21,257	$ 23,124
G	-	-	-	6,859	26,769
H	1,573	812	12,317	6,279	-
	$ 3,368	$ 10,685	$ 27,516	$ 34,395	$ 49,893

5. Oil and Gas Properties, Buildings and Equipment

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

	2002	2001
Oil and gas:		
Proved properties:		
Producing properties, including intangible drilling costs	$ 180,942	$ 168,930
Lease and well equipment(1)	167,642	146,393
	348,584	315,323
Less accumulated depreciation, depletion and amortization	121,695	108,170
	226,889	207,153
Commercial and other:		
Land	173	173
Buildings and improvements	3,838	4,086
Machinery and equipment	3,922	3,634
	7,933	7,893
Less accumulated depreciation	6,347	6,186
	1,586	1,707
	$ 228,475	$ 208,860

(1)Includes cogeneration facility costs.

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

	2002	2001	2000
Acquisition of properties/ facilities	$ 5,880	$ 2,273	$ 3,204
Development	30,817	15,875	26,145
	$ 36,697	$ 18,148	$ 29,349

In 2002, the Company acquired approximately 243,000 acres for the potential development of coalbed methane (CBM) natural gas production in Kansas and Illinois for a total of approximately $5.9 million. The projects are in an early stage of evaluation, with no significant production at December 31, 2002, and thus no reserves were recorded at year-end associated with the acquired acreage. 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. Approximately 1.1 million equivalent barrels of proved reserves were added by these acquisitions and subsequent development. The 2000 acquisition included the Castruccio property at the Company's Placerita area which included 1.5 million barrels of reserves.

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

Results of operations from oil and gas producing and exploration activities

The results of operations from oil and gas producing and exploration activities (excluding corporate overhead and interest costs) for the three years ended December 31 are as follows (in thousands):

	2002	2001	2000
Sales to unaffiliated parties	$ 102,026	$ 100,146	$ 118,801
Production costs	(44,604)	(40,281)	(46,789)
Depreciation, depletion and amortization	(16,124)	(16,175)	(13,712)
	41,298	43,690	58,300
Income tax expenses	(7,933)	(10,740)	(15,668)
Results of operations from producing and exploration activities	$ 33,365	$ 32,950	$ 42,632

6. Debt Obligations

	2002	2001	2000
Long-term debt for the years ended December 31 (in thousands):			
Revolving bank facility	$ 15,000	$ 25,000	$ 25,000

On July 22, 1999, the Company executed an Amended and Restated Credit Agreement (the Agreement) with a banking group, which consists of four banks, for a $150 million unsecured loan. At December 31, 2002 and 2001, the Company had $15 and $25 million, respectively, outstanding under the Agreement. In addition to the $15 million in borrowings under the Agreement, the Company has $5.2 million of outstanding Letters of Credit and the remaining credit available under the Agreement is therefore, $129.8 million at December 31, 2002. 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 revolving period is scheduled to terminate on January 21, 2004. Interest on amounts borrowed is charged at the lower of the lead bank's base rate or at London Interbank Offered Rates (LIBOR) plus 75 to 150 basis points, depending on the ratio of outstanding credit to the borrowing base. The weighted average interest rate on outstanding borrowings at December 31, 2002 was 2.25%. The Company pays a commitment fee of 25 to 35 basis points on the available unused portion of the commitment. The credit agreement contains other restrictive covenants as defined in the Agreement.

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.

7. Shareholders' Equity (cont'd)

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.

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 Shareholder Rights Agreement approved in December 1989 which expired on December 8, 1999.

In conjunction with the acquisition of the Tannehill assets in 1996, the Company issued a Warrant Certificate to the beneficial owners of Tannehill Oil Company. This Warrant authorized the purchase of 100,000 shares of Berry Petroleum Company Class A Common Stock until November 8, 2003 at $14.06 per share. The Warrant was purchased from the holders in 2002 and has been canceled.

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.

The Company issued 19,717, 6,529 and 21,325 shares in 2002, 2001 and 2000, respectively, through its stock option plan.

At December 31, 2002, 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. Income Taxes

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

	2002	2000	2001
Current:			
Federal	$ 2,700	$ 3,108	$ 10,336
State	1,032	1,119	3,165
	3,732	4,227	13,501
Deferred:			
Federal	4,258	1,755	1,787
State	(400)	(682)	(795)
	3,858	1,073	992
Total	$ 7,590	$ 5,300	$ 14,493

8. 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 noncurrent 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):

	2002	2001	2000
Deferred tax asset			
Federal benefit of state taxes	$ 350	$ 392	$ 871
Credit/deduction carryforwards	16,825	11,599	7,761
Other, net	(1,205)	579	1,261
	15,970	12,570	9,893
Deferred tax liability			
Depreciation and depletion	(50,829)	(43,608)	(39,894)
Other, net	173	210	246
	(50,656)	(43,398)	(39,648)
Net deferred tax liability	$(34,686)	$(30,828)	$(29,755)

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

	2002	2001	2000
Tax computed at statutory federal rate	35%	35%	35%
State income taxes, net of federal benefit	1	1	2
Tax credits	(15)	(16)	(11)
Other	(1)	(1)	2
Effective tax rate	20%	19%	28%

The Company has approximately $13 million of federal and $8 million of state (California) enhanced oil recovery (EOR) tax credit carryforwards available to reduce future income taxes. Total EOR credits of $1 million, $3 million, $8 million and $9 million will expire in 2014, 2015, 2016 and 2017, respectively.

9. Commitment

Corporate Offices Operating Lease

The Company relocated its corporate offices in March 2002. The lease term is from January 1, 2002 through October 31, 2006 and requires minimum rental payments of $36,692/month. In February 2003, the Company leased an office in Denver through March 2004 to assist in the Company's acquisition strategy, which requires minimum rental payments of $2,307 per month. The total minimum rental payments of both leases is as follows:

Year ending December 31,	
2003	$ 464,861
2004	447,227
2005	440,305
2006	366,920
Total	$ 1,719,313

Firm Transportation-Natural Gas Purchases

In 2001, the Company entered into a 12,000 Mmbtu/day firm transportation agreement related to the expansion project on the Kern River pipeline. This project is expected to be completed with gas deliveries to commence in mid-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. This represents a 10-year, take-or-pay commitment of approximately $31 million over the length of the contract.

10. 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 (PRP), 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 which could be identified in the future for cleanup, 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 materially affect the Company.

11. 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.

11. Stock Option Plan (cont'd)

On December 6, 2002, February 1, 2002, December 7, 2001 and December 1, 2000, 151,200, 40,000, 199,500 and 262,000 options, respectively, were issued to eligible employees at an exercise price of $16.50, $14.89, $16.30 and $15.69 per share, respectively, which was the closing market price of the Company's Class A Common Stock on the New York Stock Exchange on those dates. 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 2 at the fair value on the date of grant. The options granted to the non-employee Directors vest immediately. Through the 1994 Plan, 50,000, 40,000, and 40,000 options, respectively, were issued on December 2, 2002, 2001 and 2000, (5,000 options to each of the non-employee Directors each year) at an exercise price of $16.14, $15.45 and $15.69 per share, respectively.

The following is a summary of stock-based compensation activity for the years 2002, 2001 and 2000.

	2002 Options	2001 Options	2000 Options
Balance outstanding, January 1	1,474,962	1,407,837	1,220,630
Granted	241,200	239,500	302,000

Exercised	(95,837)	(65,125)	(114,793)
Canceled/expired	(15,750)	(107,250)	-
Balance outstanding, December 31	1,604,575	1,474,962	1,407,837
Balance exercisable at December 31	1,153,000	1,010,712	872,587
Available for future grant	1,007,100	232,550	364,800
Exercise price-range	$ 16.56 to 18.05	$ 14.40 to 16.96	$ 16.44 to 19.00
Weighted average remaining contractual life (years)	7	7	8
Weighted average fair value per option granted during the year based on the Black-Scholes pricing model	$ 5.25	$ 5.87	$ 4.62

Weighted average option exercise price information for the years 2002, 2001 and 2000 as follows:

	2002	2001	2000
Outstanding at January 1	$ 14.80	$ 14.58	$ 14.15
Granted during the year	16.14	16.16	15.69
Exercised during the year	11.87	13.12	12.91
Expired during the year	15.92	16.01	-
Outstanding at December 31	15.17	14.80	14.58
Exercisable at December 31	14.81	14.55	14.50

12. 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 $.4 million in 2002, $.4 million in 2001 and $.5 million in 2000. On average, approximately 94% of eligible employees participate in the plan.

13. Abandonment Obligation

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 future abandonment obligations per SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." As allowed under SFAS No. 19, the Company's estimated costs, net of salvage value, of plugging and abandoning oil and gas wells and related facilities were accrued using the units-of-production method and were taken into account when recording DD&A expense. Under SFAS No. 143, the future retirement obligation is recorded at fair value taking into consideration the Company's estimates of the current abandonment liability, the inflation rate utilized to inflate the current obligation to the estimated value at the end of reserve lives, and the Company's credit-adjusted borrowing rate used to discount the future value to a current fair value of the obligation. The abandonment costs are recorded as part of oil and gas properties and are depreciated using the units-of-production method and the abandonment obligation is increased each accounting period by recording accretion expense. In 2002, the Company implemented this new standard which had an immaterial effect on the Company's net income. The accrued abandonment obligation at December 31, 2002 was $4.6 million. The recorded abandonment obligation at December 31, 2001 under the previous accounting method of $5.4 million was reclassified to a long-term liability account in the current year presentation for comparability purposes. It is anticipated that the charge to income for future abandonment costs over the next several years will be lower than the amounts previously accrued under SFAS No. 19. Using the fair value method required under SFAS No. 143, the majority of the abandonment obligation is recorded toward the end of the life of the producing assets.

14. Quarterly Financial Data (unaudited)

The following is a tabulation of unaudited quarterly operating results for 2002 and 2001 (in thousands, except per share data):

2002	Operating Revenues	Gross Profit	Net Income	Basic net Income Per Share	Diluted net Income Per Share
First Quarter	$ 26,992	$ 8,014	$ 8,620	$ .40	$ .40
Second Quarter	32,045	10,482	6,827	.31	.31
Third Quarter	35,216	12,599	7,587	.35	.35
Fourth Quarter	36,600	10,534	6,990	.32	.32
	$ 130,853	$ 41,629	$ 30,024	$ 1.38	$ 1.37
2001					
First Quarter	$ 47,915	$ 15,365	$ 5,022	$ .23	$ .23
Second Quarter	29,047	12,755	6,975	.32	.32
Third Quarter	31,995	8,900	5,892	.27	.27
Fourth Quarter	27,108	5,210	4,049	.19	.18
	$ 136,065	$ 42,230	$ 21,938	$ 1.00	$ .99

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, 2002, 2001 and 2000. 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, 2002, 2001 and 2000, and changes in such quantities during each of the years then ended were as follows (in thousands):

2002		2001		2000	
Oil	Gas	Oil	Gas	Oil	Gas

	Mbbls	Mmcf	Mbbls	Mmcf	Mbbls	Mmcf
Proved developed and Undeveloped reserves:						
Beginning of year	101,701	6,926	106,664	4,184	111,888	3,920
Revision of previous estimates	(30)	(307)	33	153	(1,284)	463
Improved recovery	752	-	-	-	-	-
Extensions and discoveries	3,444	-	-	-	-	-
Production	(5,123)	(769)	(4,996)	(288)	(5,434)	(199)
Purchase of reserves in place	-	-	-	2,877	1,494	-
End of year	100,744	5,850	101,701	6,926	106,664	4,184
Proved developed reserves:						
Beginning of year	79,317	3,518	81,132	1,635	86,717	1,371
End of year	72,889	3,252	79,317	3,518	81,132	1,635

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.

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

	2002	2001	2000
Future cash inflows	$ 2,533,410	$ 1,452,946	$ 2,268,932
Future production and development costs	(1,283,060)	(699,505)	(653,808)
Future income tax expenses	(317,808)	(184,064)	(512,012)
Future net cash flows	932,542	569,377	1,103,112
10% annual discount for estimated timimg of cash flows	(480,355)	(289,036)	(599,530)
Standardized measure of discounted future net cash flows	$ 452,187	$ 280,341	$ 503,582
Pre-tax standardized measure of discounted future net cash flows	$ 602,157	$ 356,556	$ 721,770
Average sales prices at December 31:			
Oil($/Bbl)	$ 24.92	$ 14.16	$ 20.84
Gas($/Mcf)	$ 3.94	$ 1.87	$ 10.97

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

	2002	2001	2000
Standardized measure-beginning of year	$ 280,341	$ 503,582	$ 496,482
Sales of oil and gas produced, net of production costs	(57,422)	(59,865)	(72,358)
Revisions to estimates of proved reserves:			
Net changes in sales prices and production costs	288,870	(407,519)	98,744

Revisions of previous quantity estimates	(560)	230	(9,295)
Improved recovery	5,159	-	-
Extensions and discoveries	23,628	-	-
Change in estimated future development costs	(74,566)	48,689	(78,328)
Purchases of reserves in place	-	2,606	14,135
Development costs incurred during the period	30,632	14,895	25,253
Accretion of discount	35,656	72,177	71,455
Income taxes	(63,112)	135,792	(3,929)
Other	(16,439)	(30,246)	(38,577)
Net increase (decrease)	171,846	(223,241)	7,100
Standardized measure - end of year	$ 452,187	$ 280,341	$ 503,582

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

None.

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 caption "Election of Directors" 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. The information on Executive Officers is contained in Part I of this Form 10-K.

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.

Compliance with Section 16(a) of the Securities Exchange Act of 1934

Section 16(a) of the Securities Exchange Act of 1934 and related Securities and Exchange Commission rules require that directors, executive officers and beneficial owners of 10% or more of any class of equity securities report to the Securities and Exchange Commission changes in their beneficial ownership of the Company's Capital Stock and that any late filings be disclosed. Based solely on a review of the copies of such forms furnished to the Company, or written representations that no Form 5 was required, the Company believes in 2002 that there has been compliance with all Section 16(a) filing requirements except for Mr. Busch who filed three late Form 4's for the sale of shares from a trust at Union Bank.

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.

PART IV

Item 14. Controls and Procedures

Within the 90 days prior to the date of this report, the Company carried out an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-14 of the Securities Exchange Act of 1934. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures are effective in timely identifying material information potentially required to be included in the Company's SEC filings.

There were no significant changes in the Company's internal controls or other factors that could significantly affect these controls subsequent to the date of their evaluation and there were no corrective actions required with regard to significant deficiencies and material weaknesses.

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

On February 13, 2003, the Company filed a Form 8-K reporting an Item 5. Other Event to furnish the Securities and Exchange Commission a copy of the Company's earnings press release for the year ended December 31, 2002.

C. Exhibits

Exhibit No.	Description of Exhibit	Page
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*	Amended and Restated Credit Agreement, dated as of July 22, 1999, by and between the Registrant and Bank of America, N.A., the First National Bank of Chicago and other financial institutions (filed as Exhibit 10.7 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 1-9735)	
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.	50

Exhibits (cont'd)

Exhibit No.	Description of Exhibit	Page
10.10	Amended and Restated Non-Employee Director Deferred Stock and Compensation Plan	55
23.1	Consent of PricewaterhouseCoopers LLP	62
23.2	Consent of DeGolyer and MacNaughton	63
99.1	Undertaking for Form S-8 Registration Statements	64
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)	
99.4	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	65
99.5	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	66

*   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 March 7, 2003.

BERRY PETROLEUM COMPANY

/s/ JERRY V. HOFFMAN	/s/ RALPH J. GOEHRING	/s/ DONALD A. DALE
JERRY V. HOFFMAN	RALPH J. GOEHRING	DONALD A. DALE
Chairman of the Board, Director, President and Chief Executive Officer	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	Controller (Principal Accounting Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities on the dates so indicated.

Name	Office	Date
/s/ Jerry V. Hoffman Jerry V. Hoffman	Chairman of the Board, Director, President & Chief Executive Officer	March 7, 2003
/s/ William F. Berry William F. Berry	Director	March 7, 2003
/s/ Ralph B. Busch, III Ralph B. Busch, III	Director	March 7, 2003

/s/ William E. Bush, Jr. William E. Bush, Jr.	Director	March 7, 2003
/s/ Stephen L. Cropper Stephen L. Cropper	Director	March 7, 2003
/s/ J. Herbert Gaul, Jr. J. Herbert Gaul, Jr.	Director	March 7, 2003
/s/ John A. Hagg John A. Hagg	Director	March 7, 2003
/s/ Robert F. Heinemann Robert F. Heinemann	Director	March 7, 2003
/s/ Thomas J. Jamieson Thomas J. Jamieson	Director	March 7, 2003
/s/ Martin H. Young, Jr. Martin H. Young, Jr.	Director	March 7, 2003

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Jerry V. Hoffman, Chairman, President and Chief Executive Officer of Berry Petroleum Company, certify that:

1. I have reviewed this annual report on Form 10-K of Berry Petroleum Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant is made known to us by others within the registrant, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors:

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 10, 2003

/s/ Jerry V. Hoffman
Jerry V. Hoffman
Chairman, President and
Chief Executive Officer

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Ralph J. Goehring, Senior Vice President and Chief Financial Officer of Berry Petroleum Company, certify that:

1. I have reviewed this annual report on Form 10-K of Berry Petroleum Company;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant is made known to us by others within the registrant, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors:

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 10, 2003

/s/ Ralph J. Goehring
Ralph J. Goehring
Senior Vice President and
Chief Financial Officer

Berry Petroleum Company
5201 Truxtun Ave., Suite 300
Bakersfield, CA 93309-0640

Attention: Mr. Ron Cross
Mr. Michael Duginski

Equiva Purchase Contract
No.: BEP10132LP
Contract Dated: 8/01/02

Gentlemen:

THIS AGREEMENT is made and entered into by and between EQUIVA TRADING COMPANY, a Delaware General Partnership ("Buyer"), and BERRY PETROLEUM COMPANY, a Delaware Corporation, ("Seller") acting for itself and in its capacity as the Operator of the attached listed properties for the benefit of itself, and sets forth the terms, conditions and provisions under which Seller will sell and deliver and Buyer will purchase and receive certain crude oil.

The crude oil that is sold and purchased under this Agreement is that crude oil produced from the field wells located within the area of the leases listed, which area consists of lands covered by the oil and gas leases and/or other properties that are specifically described on the Schedule of Covered Producing Properties that is attached to this Agreement as Exhibit B, all of which lands are located in California, to the full extent, but only to the extent that Seller owns such crude oil production or otherwise controls the right to market and sell such crude oil production. Seller shall sell and deliver and Buyer shall purchase and receive all such crude oil during the delivery term provided for in this Agreement, all in accordance with and subject to all of the terms, conditions and provisions of this Agreement. However, nothing in this Agreement shall obligate Seller to produce any particular volume of crude oil or to produce any crude oil at all from any of the lands listed.

In addition to the foregoing, the terms, conditions and provisions of this Agreement consist of and include the Special Provisions attached to this Agreement as Exhibit A and the TTTI General Provisions (December 1990), as modified by Buyer and Seller and attached to this Agreement as Exhibit C. Each of Exhibit A, Exhibit B, and Exhibit C are incorporated into and made a part of this Agreement. In the event of any inconsistencies between Exhibit A and Exhibit C, the terms, conditions and provisions of Exhibit A (Special Provisions) shall prevail.

IN WITNESS WHEREOF, Buyer and Seller have caused this Agreement to be executed in duplicate on the date set forth opposite their respective signatures.

Please return one fully executed original of this Agreement to the attention of Contract Administrator.

Very truly yours,

BERRY PETROLEUM COMPANY	EQUIVA TRADING COMPANY
By: s/s Michael Duginski Michael Duginski Vice President U.S. West Coast Corporate Development	By: s/s Jimmy French Jimmy French Manager, Crude Oil Acquisitions
Date: 30/July/02	By: s/s Mike Purdy Mike Purdy Manager Lease Crude Oil Acquisitions
	Date: 7/30/02

Dated: 8/01/02

EXHIBIT A

Berry Petroleum Company, Inc

Contact: Ron Cross	Equiva Contact: Mike Purdy
Phone: 661-616-3821	Phone: 661-328-2311

Berry Petroleum Company, Inc Sale and Delivery to Equiva:

Amends	Supercedes Contract BEP1011LP Midway Sunset Supercedes Contract BEP1010LP Placerita Supercedes Contract BEP1005CP Montalvo
Quality	Midway Sunset merchantable oil (approximately 13 gravity). Placerita merchantable oil (approximately 13 gravity). Montalvo merchantable oil (approximately 27gravity).
Quantity	Approximately 15,000b/d of oil from Midway Sunset, Placerita, & Montalvo fields as described in Exhibit B.
Delivery point	From lease tankage into Equiva Trading Company nominated pipeline, transfer line, or truck crude carrier. Measurement shall be by appropriate ASTM designated custody transfer method.
Term	This contract shall be in effect August 1, 2002. The new contract pricing set forth below for all of the volume shall begin on the first day of the first month the additional Formax volume can be added to the contract volume. Until such time as 100% of the Formax crude is nominated to Equiva, the pricing terms defined in contracts BEP1011LP, BEP1010LP and BEP1005CP shall remain in effect. This contract shall continue until December 31, 2005 and month to month thereafter until the first of the month following either company's sixty (60) day advanced written notice of termination. The payment due date shall be on or before the 20th day of the month following the delivery month.
Pricing Midway Sunset & Placerita Pricing Montalvo	All heavy barrels from Midway Sunset & Placerita shall be priced monthly at the higher of 1) the Monthly Calendar average NYMEX LESS [*] OR 2) the average of Chevron, Union 76, Exxon/Mobil, and Equiva Trading Company's posting for Midway-Sunset crude PLUS a premium of [*] per barrel with either price being gravity adjusted from 13 degrees. The Montalvo light barrels produced from the McGrath 4 Pool lease shall be priced at the monthly calendar average of postings by Union 76 and Equiva Trading Company for Ventura Avenue Crude, gravity adjusted from 28 degrees, PLUS a premium of [*] per barrel. Montalvo light barrels in excess of 100 BOPD monthly average shall incur a transportation charge of [*] per barrel. [*] represents confidential material which has been redacted. A Confidential Treatment Request, including the redacted material, has been filed separately with the Commission pursuant to Rule 24b-2 of the Securities Exchange Act of 1934, as amended.
New Volumes	The approximate volume of the total purchase is 15,000 b/d +/- as described in Exhibit B. Montalvo lease light oil is being added to this contract. Berry Petroleum shall have the right to add additional volumes of San Joaquin Valley heavy crude of similar type and quality as the crude being produced from Berry's Midway Sunset properties ("New Volume"). [*] In the event of New Volume there shall be no transportation charge for delivery from the Berry Central Facility and delivery from any other point may incur a transportation charge as the

parties may mutually agree at the time any New Volume is added to this Contract to reflect added distance to the Shell pipeline compared to distance from the Berry Central Facility to the Shell pipeline.

[*] represents confidential material which has been redacted. A Confidential Treatment Request, including the redacted material, has been filed separately with the Commission pursuant to Rule 24b-2 of the Securities Exchange Act of 1934, as amended.

Assignment and Succession	Should Berry Petroleum Company be acquired or merged into another entity, this contract shall remain in effect for the succeeding entity. Should Equiva Trading Company be acquired or merged into another entity, this contract shall remain in effect for the succeeding party. Neither Party shall assign the Agreement or its rights hereunder without prior written consent of the other Party.
All Other Terms	All other terms and conditions shall remain the same.

Equiva Purchase Contract No.: BEP10132LP
Dated: 8/01/02

EXHIBIT B

CUSTOMER NAME: Berry Petroleum Company, Inc
EQUIVA TRADING COMPANY
ETCO CONTRACT NO.:
CONTRACT DATE: 9/01/02

LEASE NUMBER	PROPERTY NAME	COUNTY	FIELD	TERMS	APPROX. LEASE August 2002 TOTAL DELIVERY	TRANSPORTATION METHOD
52485	Central Facility	Kern	Midway SS	8/1/02-12/31/05	7000	Equiva design. PPL
01817	Formax	Kern	Midway SS	8/1/02-12/31/05	3200	Equiva design. PPL
Various	NMWSS	Kern	Midway SS	8/1/02 - 12/31/05	550	Equiva designated PPL
01733	Ethel D	Kern	Midway SS	8/1/02-12/31/05	125	Equiva design. PPL
52312	Placerita	Los Angeles	Placerita	8/1/02-12/31/05	3,000	Equiva design. trucks
52329	McGrath #4	Ventura	Montalvo	8/1/02-12/31/05	50	Equiva design. trucks

ATTACHMENT C ETCO CONTRACT NO.: BEP10132LP CONTRACT DATE: 8/01/02

TEXACO TRADING & TRANSPORTATION, INC.
GENERAL PROVISIONS

SPECIFIC TERMS: The specific terms of the Contracts between the Buyer and the Seller, including a description of the crude oil, condensate and/or natural gas liquids (`liquid hydrocarbons") subject thereto, quantity, price, shipment and payment terms, are set forth in specific Agreements between the Buyer and the Seller, which, together with the printed terms below, constitute integrated Contracts between the parties. In the event of any inconsistency between the printed terms below and such specific terms, the specific terms shall prevail.

WARRANTY/TAXES: The Seller warrants good title to all liquid hydrocarbons delivered pursuant to this Contract and warrants that such shall be free from all royalties, liens, encumbrances and all applicable foreign, Federal, State and local taxes that are imposed upon the production and/or removal of liquid hydrocarbons from the premises through the point of delivery. Seller further warrants that such liquid hydrocarbons have been produced, handled and transported to the point of delivery in accordance with all applicable laws, rules and regulations of all Federal, State and local authorities. Seller further warrants that all liquid hydrocarbons will be merchantable. Merchantable liquid hydrocarbons are defined as unrefined liquid hydrocarbons of the type set forth in the specific Agreements between the parties which are suitable for normal refinery processing, meet the specifications of delivering carriers and are free of foreign contaminants and chemicals including but not limited to chlorinated and oxygenated hydrocarbons. Buyer shall be liable for and shall remit to the proper government authorities any new or additional Federal, State, municipal or other regulatory body's taxes, inspection fees, transfer taxes or fees, occupation taxes or other like assessments or charges that may be applicable to liquid hydrocarbons after the point of delivery. If any tax imposed by 26 U.S.C. Sec. 4611 (the tax on petroleum under the Superfund Amendments and Reauthorization Act of 1986) shall be applicable after the point of delivery to a purchase, sale or exchange pursuant to this Contract, the Buyer shall be liable for payment and shall be responsible for remittance of such tax to the appropriate governmental authority.

TITLE AND RISK OF LOSS: Title to, possession of and risk of loss of liquid hydrocarbons shall pass to the Buyer as the liquid hydrocarbons pass from equipment or location owned or controlled by the Seller or owned or controlled by a Party designated to make delivery on behalf of the Seller, into equipment owned or controlled by the Buyer or owned or controlled by a Party designated to take delivery on behalf of the Buyer. Provided, however, that in cases of line transfers, title to, possession of and risk of loss of liquid hydrocarbons shall pass to Buyer as the liquid hydrocarbons are deemed transferred. Such shall be deemed transferred to Buyer upon completion of each in line transfer with quantity determined when available in accordance with the transfer statement or other receipt issued by the carrier or storage facility.

EQUAL DELIVERIES: For purposes of determining price, liquid hydrocarbons delivered during any given month hereunder shall be deemed to have been delivered in equal daily quantities during such month.

MEASUREMENTS AND TESTS: All measurement hereunder shall represent one hundred percent (100%) volume with such volume and gravity adjusted to sixty degrees (60) Fahrenheit temperature. Procedures for measuring and testing, except for deliveries through positive displacement-type delivery, shall be according to ASTM published methods then in effect. Procedures for such metered-type delivery shall be according to latest ASME-API published methods then in effect. The liquid hydrocarbons delivered hereunder shall be merchantable and acceptable to the carriers involved, and full deduction shall be made for all BS&W

content according to the latest ASTM standard method then in effect. Should either Party hereto fail to have a representative present during such measuring and testing, the measurements and tests of the other Party will be accepted.

CONFIRMATION OF DELIVERY: Confirmation of delivery shall be based on run tickets evidencing such delivery or allocations statements issued by the carriers involved.

CONFIRMATION OF EXCHANGE BALANCES: If this Contract is for the exchange of liquid hydrocarbons and is in effect within sixty (60) days after delivery thereunder is completed, each Party agrees to confirm in writing to the other Party the status in barrels of liquid hydrocarbons of mutual and reciprocal obligations to deliver liquid hydrocarbons.

DIVISION ORDERS: In the event either Party signs a division order in favor of the other Party pertaining to the object of this Contract, the terms of this Contract shall supersede the terms of such division order to the extent there may be a conflict between the two.

FINANCIAL RESPONSIBILITY: Should Buyer's credit or financial responsibility become unsatisfactory to Seller at any time while a Contract is in effect between the parties, cash payments or security satisfactory to Seller may be required by Seller before proceeding. In the event either Party (the "Non-Performing Party") shall (I) make an assignment or any general arrangement for the benefit of credits, (II) default in the payment or performance of any Contract between the parties, (III) file a petition or otherwise commence or authorize the commencement of a proceeding or case under any bankruptcy or similar law for the protection of creditors or have such petition filed or proceeding commenced against it, (IV) otherwise become bankrupt or insolvent (however evidenced), (V) be unable to pay its debts as they fall due, or (VI) fail to give adequate security for or assurance of its ability to perform its obligation under any Contract between the parties within 48 hours of a reasonable request therefor, then in any such event, the other Party (the "Performing Party") shall have the right to (I) withhold shipments or terminate any or all Contracts between the parties without notice, and/or (II) immediately liquidate any or all forward Contracts then outstanding between the parties by closing out each such forward Contract by buying from the Non-Performing Party the material purchased and sold thereunder and calculating market damages equal to the differences, if any, between the value specified in such Contract and the then prevailing market rates as reasonable determined by the Performing Party, setting off all market damages so determined and payable by each of the parties to the other, setting off all margin held by either Party to secure the obligations of the other Party, (including all payments due the other Party with respect to deliveries received from such other Party, which payments, prior to payment, shall be deemed to be held by each Party as margin to secure the other Party's obligations from time to time incurred), whereupon all such amounts shall be aggregated or netted to a single liquidated amount payable within one business day by the Party owing the greater such amount to the other. The exercise by either Party of any right reserved under this section shall be in addition to and not in limitation or exclusion of any other rights which such Party may have (whether by operation of law or otherwise) including any rights and remedies under the Uniform Commercial Code.

ASSIGNMENT: Neither Party shall assign this Contract without the prior written consent of the other.

TERMINATION AGREEMENT: The parties agree that any quantity of liquid hydrocarbons due and owing or to become due from one Party to the other pursuant to this Contract may be waived or otherwise settled by mutual agreement of the parties, in writing.

FORCE MAJEURE: Neither Party shall be liable to the other for failure or delay in making or accepting delivery hereunder to the extent that such failure or delay may be due to compliance with acts, orders, regulations or requests of any Federal, State or local civilian or military authority or any other persons purporting to act therefor; riots; strikes; labor difficulties; action of the elements; transportation difficulties; or any other cause reasonably beyond the control of such Party, whether Seller or not. For the purposes of this section, the term "Party" shall be defined to include Seller's supplier and Buyer's receiver. Seller shall not be obligated to make up any deliveries omitted as a result of any of the causes enumerated in this section except that Seller and Buyer are required to reconcile or balance zero value exchanges. In the event either Party is claiming (Telex or other electronic communication acceptable) with as much advance notice as is possible the underlying circumstances of the particular cause(s) of Force Majeure and the expected duration thereof and notwithstanding the provisions of this section, Buyer shall not be relieved of any obligation to make payments with regard to liquid hydrocarbons that have been delivered hereunder.

GOVERNING LAW AND JURISDICTION: This Contract shall be construed and governed by the laws of the State of California to the exclusion of any other legal system, and each Party expressly submits to the jurisdiction venue of the courts of the State of California or the federal courts in Colorado for the purposes of litigation.

NEW OR CHANGED REGULATIONS: Each of the parties hereto is entering this Contract in reliance on the laws, taxes, fees, duties, rules, regulations, decrees, agreements, concessions and arrangements with government or governmental instrumentalities (the "Regulations") in effect on the date of this Contract which directly or indirectly affect the oil sold and to be delivered hereunder insofar as these Regulations affect the Seller, the Seller's supplier, the Buyer or the receiver.

In the event that during the term of this Contract any of the Regulations or changed or new Regulations become effective and the effect of such new or changed Regulations is not covered by any other provision of this Contract and said change has a material adverse economic impact upon the parties named above, the Party affected or if the Seller's supplier, the Seller, or if the Buyer's receiver, the Buyer, in the exercise of good faith shall have the option to request renegotiations of the prices and/or other relevant terms of this Contract with respect to deliveries not yet made. In the event the Buyer or Seller is in good faith dissatisfied with the results of the renegotiation, either Party will have the right to cancel this Contract if notice of such cancellation is given in writing to the other Party within thirty (30) days of the effective date of (I) the change of the Regulations or (II) the new Regulations.

PAYMENT: Seller and Buyer shall use as a basis for payment for the liquid hydrocarbons delivered run tickets or any acceptable ASTM measurement method. Those tickets shall be delivered by the responsible party as soon as possible after the close of each calendar month during which deliveries are made but not later than five business days prior to payment due date. Payment shall be in immediately available US Dollars. Payments due on Saturday or bank holidays shall be made on the preceding business day, unless such holiday is a Monday in which case payment shall be made on the following business day; payments due on Sunday shall be made on the following business day. Past due accounts shall accrue interest at the published rate for commercial loans quoted by Morgan Guaranty Trust Company of New York.

RIGHTS OF SETOFF: In the event that either Party shall default in any payment or other performance under this or any other Contract existing by and between the parties hereto, or if any suit, claim, demand, action or cause of action shall be instituted involving any sums due under this or any other such Contract, then and in any of these events, the other Party, at its option, shall have the right to withhold any payments or any deliveries of liquid hydrocarbons due under this or any other such Contract, or offset and deduct from any payments of deliveries due under this or any other such Contract.

AUDIT: Each Party and its duly authorized representatives shall have access to the accounting records and other documents maintained by the other Party which relate to this Contract, and shall have the right to audit such records at any reasonable time or times within three years after termination of this Contract.

WAIVER: No waiver by either Party of any breach of any of the covenants or conditions herein contained to be performed by the other Party shall be construed as a waiver of any succeeding breach of the same or of any covenant or condition hereof.

TIMING: References to calendar dates set forth in this Contract and any amendments hereto, shall mean 7:00 A.M. of the dates indicated.

BERRY PETROLEUM COMPANY

NON-EMPLOYEE DIRECTOR

DEFERRED STOCK AND COMPENSATION PLAN

(as amended December 6, 2002)

Section 1. Establishment of Plan; Purpose. The Berry Petroleum Company Non-Employee Director Deferred Stock and Compensation Plan (the "Plan") is hereby established to permit Eligible Directors, in recognition of their contributions to the Company (a) to receive Shares in lieu of Compensation and (b) to defer recognition of their Compensation in the manner described below. The Plan is intended to enable the Company to attract, retain and motivate qualified directors and to enhance the long-term mutuality of interest between Directors and stockholders of the Company.

Section 2. Definitions. When used in this Plan, the following terms shall have the definitions set forth in this Section:

2.1. "Accounts" shall mean an Eligible Director's Stock Unit Account and Interest Account.

2.2. "Board of Directors" shall mean the Board of Directors of the Company.

2.3. "Committee" shall mean the Compensation Committee of the Board of Directors or such other committee of the Board as the Board shall designate from time to time.

2.4. "Company" shall mean Berry Petroleum Company, a Delaware corporation.

2.5. "Compensation" shall mean (a) the fee earned by an Eligible Director for service as a Director; (b) the fee, if any, earned by an Eligible Director for service as a member of a committee of the Board of Directors; and (c) the fee earned by an Eligible Director for (i) attendance at meetings of the Board of Directors and (ii) attendance at meetings of committees. All Compensation earned by an Eligible Director for the services identified in subsections (a), (b) and (c) above, shall be deemed earned by an Eligible Director and credited to the designated Accounts on the last trading day of the fiscal quarter in which such service was provided.

2.6. "Director" shall mean any member of the Board of Directors, whether or not such member is an Eligible Director.

2.7. "Effective Date" shall mean the date on which the Plan is approved by the stockholders of the Company.

2.8. "Eligible Director" shall mean a member of the Board of Directors who is not an employee of the Company.

2.9. "Exchange Act" shall mean the Securities Exchange Act of 1934, as amended.

2.10. "Fair Market Value" shall mean the closing price of a Share as reported by the New York Stock Exchange on the last trading day of such fiscal quarter on which such value is to be determined under this Plan.

2.11. "Interest Account" shall mean the bookkeeping account established to record the interests of an Eligible Director with respect to deferred Compensation that is not allocated to Units in a Stock Unit Account.

2.12. "Shares" shall mean shares of Stock.

2.13. "Stock" shall mean the Class A Common Stock of the Company.

2.14. "Stock Unit Account" shall mean a bookkeeping account established to record the interests of an Eligible Director who has elected to have deferred Compensation credited as Units in this Account.

2.15. "Unit" shall mean a contractual obligation of the Company to deliver a Share, or pay cash, based on the Fair Market Value of a Share to an Eligible Director or the beneficiary or estate of such Eligible Director as provided herein.

Section 3. Administration

. The Plan shall be administered by the Committee; provided, however, that the Plan shall be administered such that any Director participating in the Plan shall continue to be deemed to be a "disinterested person" under Rule 16b-3 of the Securities and Exchange Commission under the Exchange Act ("Rule 16b-3"), as such Rule is in effect on the Effective Date of the Plan and as it may be subsequently amended, for purposes of such Director's ability to serve on any committee charged with administering any of the Company's stock-based incentive plans for executive officers intended to qualify for the exemptive relief available under Rule 16b-3.

Section 4. Shares Authorized for Issuance.

4.1. Maximum Number of Shares. The aggregate number of Shares which may be issued to Eligible Directors under the Plan shall not exceed Two Hundred Fifty Thousand (250,000) Shares, subject to adjustment as provided in Section 4.2 below. If any Unit is distributed in cash or is forfeited without a distribution of Shares, the Shares otherwise subject to such Unit shall again be available hereunder.

4.2. Adjustment for Corporate Transactions. If the outstanding Stock is increased, decreased, changed into or exchanged for a different number or kind of shares of the Company through reorganization, recapitalization, reclassification, stock dividend, stock split or reverse stock split, an appropriate and proportionate adjustment shall be made in the number or kind of shares which may be issued in the aggregate under this Plan and the number of Units that have been, or may be, issued under this Plan; provided, however, that no such adjustment need be made if, upon the advice of counsel, the Committee determines that such adjustment may result in the receipt of federally taxable income to holders of Stock or other classes of the

Company's equity securities. The nature and extent of such adjustments shall be determined by the Committee in its sole discretion, and any such determination as to what adjustments shall be made, and the extent thereof, shall be final, binding and conclusive. No fractional shares of Stock shall be issued under this Plan pursuant to any such adjustment.

Section 5. Deferred Compensation Program.

5.1. Election to Defer. On or before December 31 of any calendar year, an Eligible Director may elect to defer receipt of all or any part of any Compensation payable in respect of the calendar year following the year in which such election is made, and to have such amounts credited, in whole or in part, to a Stock Unit Account or an Interest Account. Any person who shall become an Eligible Director during any calendar year may elect, not later than the 30th day after his term as a Director begins, to defer payment of all or any part of his Compensation payable for the portion of such calendar year following such election. In the year in which this Plan is first implemented, any Eligible Director may elect, not later than the 30th day after the Effective Date, to defer payment of all or any part of his Compensation payable for the portion of such calendar year following the Effective Date.

5.2. Method of Election. A deferral election shall be made by written notice filed with the Corporate Secretary of the Company. Such election shall continue in effect (including with respect to Compensation payable for subsequent calendar years) unless and until the Eligible Director revokes or modifies such election by written notice filed with the Corporate Secretary. Any such revocation or modification of a deferral election shall become effective as of December 31 of the year in which such notice is given and only with respect to Compensation payable in respect of the calendar year following the year in which just revocation or modification is made; provided however that if the effect of such revocation or modification of a deferral election is to change the amount of deferred Compensation that would otherwise have been credited to the Stock Unit Account it shall in no event become effective earlier than six (6) months after it is received by the Corporate Secretary. Amounts credited to the Eligible Director's Stock Unit Account prior to the effective date of any such revocation or modification of a deferral election shall not be affected by such revocation or modification and shall be credited and distributed only in accordance with the deferral election in place prior to such revocation and modification and otherwise in accordance with the applicable terms of the Plan. An Eligible Director who has revoked an election to participate in the Plan may file a new election to defer Compensation with respect to services rendered in the calendar year following the year in which such new election is filed with the Corporate Secretary of the Company.

5.3. Investment Election. At the time an Eligible Director elects to defer receipt of Compensation pursuant to Section 5.1, the Eligible Director shall also designate in writing the portion of such Compensation, stated as a whole percentage, to be credited to the Interest Account and the portion to be credited to the Stock Unit Account. If an Eligible Director fails to designate the allocation between the two Accounts, 100% of such Compensation shall be credited to the Interest Account. By written notice to the Corporate Secretary, an Eligible Director may change the investment election and the manner in which Compensation is allocated among the Accounts but only with respect to services to be rendered in the calendar year following the year in which such new investment election is filed with the Corporate Secretary, provided that any such election shall only be effective with respect to Compensation payable six (6) months after such new investment election is received by the Corporate Secretary.

5.4. Interest Account.

a. Any Compensation allocated to an Eligible Director's Interest Account shall be deemed earned and credited to the Interest Account as of the last trading day of the fiscal quarter in which the service was provided for which such compensation amount would have been paid to the Eligible Director.

b. Any amounts credited to the Interest Account shall be credited with interest at the rate of five percent (5%) per annum, compounded annually.

5.5. Stock Unit Account.

a. Any Compensation allocated to an Eligible Director's Stock Unit Account shall be deemed earned and credited to Units in the Stock Unit Account as of the last trading day of the fiscal quarter in which the service was provided for which such compensation amount would have been paid to the Eligible Director.

b. The number of Units allocated to the Eligible Director's Stock Unit Account pursuant to subsection (a) above shall be equal to the quotient of (i) the aggregate Compensation allocated to the Stock Unit Account as of the last trading day of the fiscal quarter divided by (ii) the Fair Market Value on the last trading day of such quarter. Fractional Units shall be credited, but shall be rounded to the nearest hundredth percentile, with amounts equal to or greater than .005 rounded up and amounts less than .005 rounded down.

5.6. Dividend Equivalents.

a. An Eligible Director who has elected to defer Compensation to a Stock Unit Account shall have no rights as a stockholder of the Company with respect to any Units until Shares are distributed and delivered to the Eligible Director.

b. Notwithstanding the provisions of subsection (a), each Eligible Director who has allocated Compensation to a Stock Unit Account shall have the right to receive an amount equal to the dividend per Share declared by the Company on the applicable dividend payment date (which, in the case of any dividend distributable in property other than Shares, shall be the per Share value of such dividend, as determined by the Company for purposes of income tax reporting) times the number of Units held by such Eligible Director in his Stock Unit Account (a "Dividend Equivalent").

c. Each Eligible Director may designate in writing to the Corporate Secretary, prior to any calendar year, whether any Dividend Equivalent is to be: (i) payable in cash, on or as soon as practicable after each date on which dividends are paid to stockholders with respect to Shares; (ii) deferred and credited to the Eligible Director's Interest Account; or (iii) treated as reinvested in an additional number of Units and credited to the Eligible Director's Stock Unit Account.

d. The additional number of Units to be credited to the Eligible Director's Stock Unit Account pursuant to (c) (iii) shall be determined by dividing (i) the product of (A) the number of Units in the Eligible Director's Stock Unit Account on the date the dividend is declared, and (B) the amount of any cash dividend declared by the Company on a Share (or, in the case of any dividend distributable in property other than Shares, the per share value of such dividend, as determined by the Company for purposes of income tax reporting), by (ii) the Fair Market Value on the last trading day of the fiscal quarter in which the dividend is declared.

e. Notwithstanding the date used for purposes of determining the number of additional Units as provided in subsection (d) above, the additional Units to be credited for Dividend Equivalents shall be deemed earned and credited to the Eligible Director's Stock Unit Account on the last trading day of the fiscal quarter in which such dividend is declared.

f. In the event of any stock split, stock dividend, recapitalization, reorganization or other corporate transaction affecting the capital structure of the Company, the Committee shall make such adjustments to the number of Units credited to each Eligible Director's Stock Unit Account as the Committee shall deem necessary or appropriate to prevent the dilution or enlargement of such Eligible Director's rights and such adjustment shall be made and effective as of the last day of the fiscal quarter in which such corporate transaction has occurred.

5.7. Distribution Election.

a. At the time an Eligible Director makes a deferral election pursuant to Section 5.1, the Eligible Director shall also file with the Corporate Secretary a written election (a "Distribution Election")

b. The Distribution Election shall specify the aggregate amount, if any, credited to the Interest Account at any time and the value of any Units credited to the Stock Unit Account shall be distributed (i) in cash, (ii) in Shares or (iii) in a combination thereof, provided further that any election to receive a distribution of all or any portion of the value of an Eligible Director's Interest Account in Shares must be made on an irrevocable basis at least six (6) months in advance of such distribution.

c. Such distribution shall commence, at the election of the Eligible Director, as soon as practicable following the first business day of the calendar month following the date the Eligible Director ceases to be a Director or on the first business day of any calendar year following the calendar year in which the Eligible Director ceases to be a Director.

d. Such distribution shall be in one lump sum payment or in such number of annual installments (not to exceed ten (10)) as the Eligible Director may designate. The amount of any installment payment shall be determined by multiplying the amount credited to the Accounts of an Eligible Director immediately prior to the distribution by a fraction, the numerator of which is one and the denominator of which is the number of installments (including the current installment) remaining to be paid.

e. An Eligible Director may at any time prior to the time at which the Eligible Director ceases to be a Director, and from time to time, change any Distribution Election applicable to his Accounts, provided that no election to change the timing of any final distribution shall be effective unless it is made in writing and received by the Corporate Secretary at least one (1) year prior to the time at which the Eligible Director ceases to be a director.

5.8. Financial Hardship Withdrawal. Any Eligible Director may, after submission of a written request to the Corporate Secretary and such written evidence of the Eligible Director's financial condition as the Committee may reasonably request, withdraw from his Interest Account (but not from his Stock Unit Account) up to such amount as the Committee shall determine to be necessary to alleviate the Eligible Director's financial hardship.

5.9. Timing and Form of Distributions.

a. Any distribution to be made hereunder, whether in the form of a lump sum payment or installments, following the termination of an Eligible Director's service as a Director shall commence in accordance with the Distribution Election made by the Eligible Director pursuant to Section 5.7.

b. If an Eligible Director fails to specify a form of payment for a distribution in accordance with Section 5.7, the distribution from the Interest Account shall be made in cash and the distribution from the Stock Unit Account shall be made in Shares.

c. If an Eligible Director fails to specify in accordance with Section 5.7 a commencement date for a distribution or whether such distribution shall be made in a lump sum payment or a number of installments, such distribution shall be made in a lump sum payment and commence on the first business day of the month immediately following the date on which the Eligible Director ceases to be a Director. In the case of any distribution being made in annual installments, each installment after the first installment shall be paid on the first business day of each subsequent calendar year, or as soon as practical thereafter, until the entire amount subject to such Distribution Election shall have been paid.

Section 6. Unfunded Status. The Company shall be under no obligation to establish a fund or reserve in order to pay the benefits under the Plan. A Unit represents a contractual obligation of the Company to deliver Shares or pay cash to an Eligible Director as provided herein. The Company has not segregated or earmarked any Shares or any of the Company's assets for the benefit of an Eligible Director or his beneficiary or estate, and the Plan does not, and shall not be construed to, require the Company to do so. The Eligible Director and his beneficiary or estate shall have only an unsecured, contractual right against the Company with respect to any Units granted or amounts credited to an Eligible Director's Accounts hereunder, and such right shall not be deemed superior to the right of any other creditor. Units shall not be deemed to constitute options or rights to purchase Stock.

Section 7. Amendment and Termination. The Plan may be amended at any time by the Committee or the Board of Directors. Any modification of any of the terms and provisions of the Plan, including this Section, shall not be made more than once every six (6) months. The Plan shall terminate on May 31, 2008. Unless the Board otherwise specifies at the time of such termination, the termination of the Plan will not result in the premature distribution of the amounts credited to an Eligible Director's Accounts.

Section 8. General Provisions.

8.1. No Right to Serve as a Director. This Plan shall not impose any obligations on the Company to retain any Eligible Director as a Director nor shall it impose any obligation on the part of any Eligible Director to remain as a Director of the Company.

8.2. Rights of a Terminated Director. Notwithstanding the fact that an Eligible Director ceases to be a director during any fiscal quarter, the Eligible Director's Accounts shall be credited, on the last trading day of the fiscal quarter, with all Compensation and Dividend Equivalents earned as of the last business day he served as an Eligible Director.

8.3. Construction of the Plan. The validity, construction, interpretation, administration and effect of the Plan and the rights relating to the Plan, shall be determined solely in accordance with the laws of the State of Delaware.

8.4. No Right to Particular Assets. Nothing contained in this Plan and no action taken pursuant to this Plan shall create or be construed to create a trust of any kind or any fiduciary relationship between the Company and any Eligible Director, the executor, administrator or other personal representative or designated beneficiary of such Eligible Director, or any other persons. Any reserves that may be established by the Company in connection with Units granted under this Plan shall continue to be treated as the assets of the Company for federal income tax purposes and remain subject to the claims of the Company's creditors. To the extent that any Eligible Director or the executor, administrator, or other personal representative of such Eligible Director, acquires a right to receive any payment from the Company pursuant to this Plan, such right shall be no greater than the right of an unsecured general creditor of the Company.

8.5. Severability of Provisions. If any provision of this Plan shall be held invalid or unenforceable, such invalidity or unenforceability shall not affect any other provisions hereof, and this Plan shall be construed and enforced as if such provision had not been included.

8.6. Incapacity. Any benefit payable to or for the benefit of a minor, an incompetent person or other person incapable of receipting therefor shall be deemed paid when paid to such person's guardian or to the party providing or reasonably appearing to provide for the care of such person, and such payment shall fully discharge any liability or obligation of the Board of Directors, the Company and all other parties with respect thereto.

8.7. Headings and Captions. The headings and captions herein are provided for reference and convenience only, shall not be considered part of this Plan, and shall not be employed in the construction of this Plan.

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (No. 333-98379)of Berry Petroleum Company of our report dated February 12, 2003 relating to the financial statements, which appears in the Annual Report to Shareholders, which is incorporated in this Annual Report on Form 10-K.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
March 10, 2003
Los Angeles, California

EXHIBIT 23.1

February 27, 2003

Berry Petroleum Company
5201 Truxtun Avenue, Suite 300
Bakersfield, California 93309

Gentlemen:

In connection with the Annual Report on Form 10-K for the fiscal year ended December 31, 2002, (the Annual Report) of Berry Petroleum Company (the Company), we hereby consent to (i) the use of and reference to our report dated February 14, 2003, entitled "Appraisal Report, as of December 31, 2002, on Certain Property Interests owned by Berry Petroleum Company," which pertains to interests of the Company in certain oil and gas properties located in California, Louisiana, Nevada, Oklahoma, Texas, and Wyoming; our report dated February 25, 2002, entitled "Appraisal Report, as of December 31, 2001, on Certain Property Interests owned by Berry Petroleum Company," which pertains to interests of the Company in certain oil and gas properties located in California, Louisiana, Nevada, Oklahoma, Texas, and Wyoming; our report dated February 26, 2001, entitled "Appraisal Report, as of December 31, 2000, on Certain Property Interests owned by Berry Petroleum Company," which pertains to interests of the Company in certain oil and gas properties located in California, Louisiana, Nevada, Oklahoma, Texas, and Wyoming (collectively referred to as the "Reports"), under the caption "Oil and Gas Reserves" in items 1 and 2 of the Annual Report and under the caption "Supplemental Information About Oil and Gas Producing Activities (Unaudited)" in item 8 of the Annual Report; and (ii) the use of and reference to the name DeGolyer and MacNaughton as the independent petroleum engineering firm that prepared the Reports under such items; provided, however, that since the cash-flow calculations in the Annual Report include estimated income taxes not included in the Reports, we are unable to verify the accuracy of the cash-flow values in the Annual Report.

Very truly yours,

DeGOLYER and MacNAUGHTON

EXHIBIT 23.2

UNDERTAKING FOR FORM S-8 REGISTRATION STATEMENT

For purposes of complying with the amendments to the rules governing Form S-8 (effective July 13, 1990) under the Securities Act of 1933, the Company hereby undertakes as follows, which undertaking shall be incorporated by reference into the Company's Registration Statement on Form S-8 (No. 333-98379):

Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to director, officers and controlling persons of the Company pursuant to the foregoing provisions, or otherwise, the Company has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Securities Act of 1933 and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the Company of expenses incurred or paid by a director, officer or controlling person of the Company in the successful defense of any action, suit or proceeding is asserted by such director, officer or controlling person in connection with the securities being registered, the Company will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification is against public policy as expressed in the Act and will be governed by the final adjudication of such issue.

Exhibit 99.1

Certification of CEO Pursuant to
18 U.S.C. Section 1350,
As Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Berry Petroleum Company (the "Company") on Form 10-K for the period ending December 31, 2002 as filed with the Securities and Exchange Commission on March 11, 2003 (the "Report"), Jerry V. Hoffman, as Chairman, President and Chief Executive Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of his knowledge, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Jerry V. Hoffman
Jerry V. Hoffman
Chairman, President and Chief Executive Officer
March 11, 2003

This certification accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

Exhibit 99.4

Certification of CFO Pursuant to
18 U.S.C. Section 1350,
As Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Berry Petroleum Company (the "Company") on Form 10-K for the period ending December 31, 2002 as filed with the Securities and Exchange Commission on March 11, 2003 (the "Report"), Ralph J. Goehring, Senior Vice President and Chief Financial Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of his knowledge, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Ralph J. Goehring
Ralph J. Goehring
Senior Vice President and Chief Financial Officer
March 11, 2003

This certification accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

Exhibit 99.5