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, 2001
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)
28700 Hovey Hills Road, P.O. Box 925, Taft, California 93268
(661) 769-8811

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. [ ]

As of February 15, 2002, the registrant had 20,832,996 shares of Class A Common Stock outstanding and the aggregate market value of the voting stock held by nonaffiliates was approximately $219,816,000. This calculation is based on the closing price of the shares on the New York Stock Exchange on February 15, 2002 of $14.17. The registrant also had 898,892 shares of Class B Stock outstanding on February 15, 2002, 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

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, 2001. 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 primarily 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. 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. The Company has over $100 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, 2001, the Company's estimated proved reserves were 103 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, 2001 were located in California, with 74%, 20% and 4% of total proved reserves in Kern, Los Angeles and Ventura Counties, respectively. The Company's reserves have a long life, in excess of 20 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 degree API gravity and the Montalvo field averages 16 degree API gravity). Production in 2001 was 5 million BOE, down 9% from 2000 production of 5.5 million BOE. For the five years 1997 through 2001, the Company's average annual reserve replacement rate was 102% and the finding and development cost was $3.69 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:

	2001	2000	1999
Sales of oil and gas	72%	69%	66%
Sales of electricity	26%	31%	33%
Other	2%	-	1%

Oil Marketing

The global and California crude oil markets have remained very volatile due to the impacts of the September 11, 2001 (9/11) terrorist attacks on the U.S. and as OPEC attempts to manage crude oil prices in the midst of fluctuating inventory levels and petroleum product demand weakness due to worldwide economic slowdowns. Oil prices remained strong in 2001 until the economic impacts of 9/11 caused the price to decline by $9/Bbl before rebounding a few dollars. The price for West Texas Intermediate (WTI), the U.S. benchmark crude oil, averaged $25.88 for 2001 compared to $30.26 in 2000 and $19.30 in 1999.

While the crude oil price differentials between WTI and California's heavy crude has widened slightly over the last two years, the Company believes that the differential will be near its historical norms over the next several years. The crude price differential between WTI and California's heavy crude oil can be volatile and has averaged $7.25, $6.36 and $5.97 for 2001, 2000 and 1999, respectively.

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. The agreement is based on a monthly determination of the highest price from any of (1) local field posted price plus a fixed bonus, (2) WTI minus a fixed differential or (3) a fixed percentage of WTI. 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.

From time to time, the Company also 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. In May of 2001, the Company entered into a one-year zero cost bracketed collar on 3,000 barrels/day (BPD) of its crude oil. The maximum the Company was obligated to pay under the hedge was $3.62/Bbl and the maximum the Company could receive under the hedge was $5.60/Bbl. The counterparty to this hedge, Enron, filed for bankruptcy on December 2, 2001. As a result, the Company terminated this contract on December 10, 2001. During 2000, the Company maintained two bracketed zero cost collar hedge contracts with two refiners entered into in previous years as part of its price protection program. This price protection program was designed to moderate the effects of a severe price downturn while allowing Berry to participate in 100% of the upside after a maximum $3.00 per barrel payment on 6,500 BPD. Of this 6,500 BPD, Berry participated on 5,000 BPD above $15.50 per barrel and on 1,500 BPD above $17.50 per barrel. These price triggers were based on California heavy oil postings and both contracts expired at December 31, 2000.

All of these price protection activities resulted in a net (benefit) or cost/Bbl to the Company of ($.16) in 2001, $1.31 in 2000 and $.51 in 1999. Berry's 2001 average heavy crude oil sales price was $19.70/Bbl, down $2.00, or 9% from $21.70 in 2000, and $13.08 in 1999.

The Company had no crude oil hedges in place at December 31, 2001. However, the Company has entered into oil price protection hedges in 2002 for a one-year period beginning April 1, 2002 on a total of 5,000 BPD. Based on WTI pricing, the hedges have a floor of approximately $20.00/Bbl and a ceiling of approximately $24.00/Bbl. In addition, its existing crude oil sales agreement does provide some protection against a severe price decline. One of the Company's properties, with production in excess of 3,000 BPD, is burdened by a price-sensitive royalty. The royalty is 75% of the heavy oil posted price above $14.30 (for 2002), escalated and calculated annually. Management regularly monitors the crude oil markets and its 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, 2001, approximately 94% of the Company's proved reserves, or 97 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 purchase of its 38 megawatt (Mw) cogeneration facility in 1995 and another 18 Mw cogeneration facility in 1996 as part of the purchase of additional oil properties in the South Midway-Sunset field. In early 1999, the Company purchased the Placerita oilfield, which is highly dependent on low-cost steam for economic production. This purchase also included a 42 Mw cogeneration facility consisting of two 21 Mw turbines. Steam generation from these facilities is more efficient than conventional steam generators, as both steam and electricity are produced from the same natural gas fuel supply. 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, the regulation of the electrical market in California is controlled by a very politically-oriented state government. The Company has been unsuccessful in obtaining an economic power sales agreement to date and has reduced its efforts regarding such contracts until the electrical marketplace in California becomes either less controlled by the state government or until the marketplace allows reasonable economics to prevail.

Midway-Sunset Field

For its South Midway-Sunset properties, the Company's steam production for 2001 was generated by its 38 Mw and 18 Mw cogeneration facilities (approximately 13,300 barrels of steam per day (BSPD) including duct-fire, 21,000 BSPD in 2000) 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, which have the capability of generating approximately 3,400 BSPD, for its steam requirements.

Placerita

On its Placerita properties, the Company generated approximately 8,600 BSPD in 2001 (12,500 BSPD in 2000) from its 42 Mw cogeneration facility and has the capability of generating another 7,600 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 exploded over HH in December 2000 by approximately $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. For 2001, the cost of natural gas purchased averaged $5.76/Mmbtu versus $4.95/Mmbtu in 2000. On March 1, 2002, SoCal gas prices were approximately $2.40/Mmbtu.

Cogeneration Steam Generation

Going into 2001, the Company had four Standard Offer (SO) electricity sales contracts related to its three cogeneration plants. 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 believes that it will be able to deliver its power generation in 2002 to paying customers and anticipates steam generation volumes from its cogeneration facilities will be similar to its pre-2001 historical levels. Until the Company can re-establish economic long-term electricity sales contracts, the cost of the Company's steam may be volatile from quarter to quarter and year to year.

The Company has physical access to gas pipelines, such as the Kern River/El Paso 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, although the project is awaiting FERC approval. 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 to Henry Hub prices.

Electricity Contracts

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

Location	Type of Contract(1)	Purchaser	Contract Expiration	Average megawatts delivered for sale per hour(2) 2001	Average megawatts delivered for sale per hour(2) 2000	Average barrels of steam delivered per day (2) 2001	Average barrels of steam delivered per day (2) 2000
Placerita							
Placerita I	SO2	Edison	3-2009	13.4	16.7	5,075	6,112
Placerita II	SO2	Edison	5-2002	10.1	16.4	3,707	6,404
South Midway-Sunset							
Cogen 18	Open Market	Various	6-2002	7.9	14.3	3,570	6,350
Cogen 38	Open Market	Various	6-2002	20.6	34.5	9,723	15,115

(1) SO is for "Standard Offer."
(2) Approximate average for 2001 based on 365 day year and 2000 based on 366 day year.

Electricity Generation

The Company's three cogeneration facilities, when combined, have electricity production capacity of 98 Mw of electricity per hour. Each facility is centrally-located on an oil property such that the steam generated by the facility is capable of being delivered to the oil properties that require the steam for production purposes. With higher natural gas prices impacting its operations so significantly, the Company is pursuing other opportunities to secure additional long-term sources of low-cost steam. 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.

During the fourth quarter of 2000, the Company experienced a significant increase in the cost of natural gas, which is used as a fuel for its cogeneration plants and steam generators. To protect itself from a pending proposed decision by the California Public Utilities Commission which would de-link the Company's natural gas cost from electricity sales under its standard offer contracts, the Company entered into several derivative contracts to hedge 4,500 Mmbtu/day of natural gas purchases for the three months ended March 31, 2001. During December 2000, the Company recorded operating costs of $.3 million related to the ineffective portion of these derivative instruments and $.4 million (net of tax effects) in other comprehensive income related to unrecognized gains from these derivative instruments. In 2001, the Company earned $1.4 million pre-tax from these hedges which was recorded as a reduction to "Operating cost - electricity generation". See Notes 2 and 3 of Notes to the Financial Statements.

One of the Company's major challenges in 2001 was to obtain the necessary approvals to sell the Company's electricity into the marketplace and enter into a contract to sell power to a creditworthy buyer. The Company terminated its two contracts with PG&E on April 2, 2001, just four days before PG&E filed for bankruptcy. On May 16, 2001, the PG&E bankruptcy judge approved a settlement that the Company had reached with PG&E whereby the utility would allow the Company to sell its power into the grid. The Company immediately entered into a sales agreement with a creditworthy third party and is delivering electricity into the grid primarily via spot sales. The Company also pursues monthly or longer-term sales arrangements. In September 2001, the Company assigned its PG&E past-due receivables to a third party for cash in the amount of $9.3 million.

Berry also terminated its two contracts with Edison, and when Edison refused to acknowledge such terminations, Berry filed the necessary lawsuits. In June 2001, Berry and Edison reached a settlement whereby Edison would prepay Berry for power deliveries and whereby Berry agreed to "standstill" on litigation matters until December 31, 2001. Berry's Placerita II contract, which expires in May 2002, stayed on a short-run avoided cost (SRAC) pricing mechanism. Berry chose to elect the five-year fixed price of 5.37 cents per kilowatt hour pricing mechanism on its Placerita I contract, which expires in March 2009. These contract amendments were approved by the CPUC in July 2001. The Company entered into two additional contract amendments with Edison whereby 1) the Company received 10% of the past-due amount and 7% accrued interest on the past-due amount, and 2) the Company extended its litigation standstill to allow Edison to become creditworthy and Edison devised a formula payment, although no specific date for payment was established. The Company received interest monthly on the past due amount. At December 31, 2001, Edison owed the Company $13.5 million and Berry had $9.3 million recorded as collectible receivables; the difference was written-off in early 2001. On March 1, 2002, Edison paid the Company $13.5 million, representing the total past due amount plus interest. The Company will record pre-tax income of $4.2 million in the first quarter of 2002 related to this cash receipt.

In late July 2001, Berry entered into a three-year SoCal gas swap with Enron for a price of $4.20/Mmbtu on 5,000 Mmbtu/day. The Company terminated this hedge contract with Enron on December 10, 2001, shortly after Enron declared bankruptcy and at the same time, the Company terminated its crude oil price hedge with Enron. The Company anticipates that it will enter into a similar gas purchasing hedge in the near future to protect its favorable spark spread related to Edison's fixed price contract.

Impact of Enron Bankruptcy

As previously described in "Oil Marketing" and "Electricity Generation" 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 by the Enron bankruptcy judge. 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 the environment as the Company strives to achieve the long-term goal of sustainable development. 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. With safety protection one of the key focuses, the Company has gone almost three years without a lost-time accident by any of its employees.

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 address risks, to train employees in the proper performance of their duties and to incorporate viable new technologies. 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 provide for additional emission reductions. 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, 2001 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, 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, 2001, the Company had 110 full-time employees, down from 115 employees at year-end 2000.

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 74% of the Company's proved oil and gas reserves and approximately 74% of its current daily production. Of these properties, 18 are owned in fee. The wells produce from an average depth of approximately 1,200 feet, and rely on thermal EOR methods, primarily cyclic steaming.

During 2001, like 2000, 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 34 wells drilled in this field in 2001, 17 were drilled on the Formax properties, and 13 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 2002, the Company plans to drill an additional 39 wells in this field, including 13 on the Formax properties, 11 of which will be horizontal.

Included in the Company's 2002 development plans for Midway-Sunset are seven exploitation wells, in both the North and South Midway-Sunset areas. In the North Midway-Sunset area, a corehole will be drilled to evaluate the extent of the diatomite accumulation in addition to four delineation wells to evaluate the extent of our 2001 step-out discovery in the Upper Tulare Zone.

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 methods, primarily steam flooding.

During 2001, the Company drilled three wells at Placerita, one of which was a water disposal service well. The other two wells were the first wells drilled as Phase One of a major development campaign at the north end of the field. Included in the Company's 2002 development plans for Placerita is the continuation of the north end development with four steamflood injection wells, three steamflood producers, and a step-out evaluation well.

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 7% of Berry's daily production. The wells produce from an average depth of approximately 11,500 feet. No new wells were drilled in 2001. There are no plans at this time to drill any new wells in 2002, however one remedial is planned. We are also pursuing the possibility of running a seismic program over selected portions of the developed area of the field in 2002 to confirm suspected bypassed oil and gas accumulations in this highly faulted, geologically complex field.

South Joe Creek - In April 2001, Berry purchased a 15.83% non-operated working interest in the South Joe Creek coalbed methane field. The Company purchased interests in federal, state and local leases totaling approximately 5,800 acres in the Campbell County portion of the Powder River Basin in Wyoming. There were 18 wells (3 net) in existence at the time of the purchase and 67 additional wells (11 net) were drilled in 2001. Another 19 wells (3 net) are planned for drilling and completion in 2002. On February 10, 2002, the production rate was 6.62 million cubic feet of gas (1.05 net) per day.

The following is a summary of the Company's capital expenditures incurred during 2001 and 2000 and projected capital expenditures for 2002.

CAPITAL EXPENDITURES SUMMARY
(in thousands)

	2002(1) (Projected)	2001	2000
South Midway-Sunset Field			
New wells	$6,550	$ 4,725	$ 10,128
Remedials/workovers	900	1,119	1,373
Facilities	1,380	3,785	1,333
	8,830	9,629	12,834
Placerita			
New wells	4,050	782	2,669
Remedials/workovers	-	465	1,001
Facilities	4,495	1,660	4,543
	8,545	2,907	8,213
North Midway-Sunset Field			
New wells	840	74	1,257
Remedials/workovers	-	248	212
Facilities	-	284	76
	840	606	1,545
Montalvo			
Remedials/workovers	100	674	420
Facilities	265	331	1,295
	365	1,005	1,715
South Joe Creek (2)			
New wells	297	593	-
Facilities	248	79	-
	545	672	-
Other	446	76	946
Totals	$19,571	$14,895	$25,253

(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.

Exploration

The Company did not participate in the drilling of any exploratory wells in 2001 or 2000 and has none budgeted for 2002. 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, 2001. 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, 2001. For the Company's operated properties, these reserve estimates are filed annually with the U.S. Department of Energy. Refer to 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:

	2001	2000	1999
Net annual production:(1)			
Oil (Mbbls)	4,996	5,434	5,060
Gas (Mmcf)	288	199	180
Total equivalent barrels(2)	5,044	5,467	5,090
Average sales price:			
Oil (per Bbl)	$19.70	$21.70	$13.08
Gas (per mcf)	5.09	4.34	1.90
Per BOE	19.79	21.72	13.07
Average operating cost - oil and gas production (per BOE)(3)	7.99	8.20	5.47

(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 $1.31, $0.53 and $0 for 2001, 2000 and 1999, respectively. See Note 2 to the financial statements.

Acreage and Wells

At December 31, 2001, the Company's properties accounted for the following developed and undeveloped acres:

	Developed Acres Gross	Developed Acres Net	Undeveloped Acres Gross	Undeveloped Acres Net
California	7,226	7,226	7,244	7,244
Other	3,720	573	1,746	277
	10,946	7,799	8,990	7,521

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 2,466 gross oil wells (2,461 net) and 88 gross gas wells (17 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:

	2001 Gross	2001 Net	2000 Gross	2000 Net	1999 Gross	1999 Net
Exploratory wells drilled:						
Productive	-	-	-	-	-	-
Dry(1)	-	-	-	-	-	-
Development wells drilled:(2)						
Productive	103	47	81	81	21	21
Dry(1)	1	-	-	-	-	-
Total wells drilled:						
Productive	103	47	81	81	21	21
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 for 2001 include 67 wells gross, 11 wells net that were drilled at South Joe Creek which the Company acquired in 2001 and holds a 15.83% working interest.

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, 2001) 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, 52, 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, 45, 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, 41, 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. 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, 35, is the Vice President of Corporate Development. Mr. Duginski, a mechanical engineer, has a Masters in Business Administration and was previously with Texaco, Inc. where he was responsible for new business development and gas and power operations. Mr. Duginski was hired by the Company effective February 1, 2002.

BRIAN L. REHKOPF, 54, 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, a subsidiary of Atlantic Richfield Corp. (ARCO) 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, 55, has been Controller since December 1985.

KENNETH A. OLSON, 46, 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 authorizes the purchase of 100,000 shares of Berry Petroleum Company Class A Common Stock until November 8, 2003 at $14.06 per share. All the warrants are currently outstanding and the underlying shares will not be registered under the Securities Act of 1933.

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 2001 and 2000 are shown below:

	2001			2000		
	Price Range		Dividends	Price Range		Dividends
	High	Low	per Share	High	Low	Per Share
First Quarter	$14.75	$12.05	$.10	$17.875	$14.063	$.10
Second Quarter	15.05	11.00	.10	17.313	14.625	.10
Third Quarter	16.99	13.65	.10	19.875	16.500	.10
Fourth Quarter	17.75	14.26	.10	18.188	11.625	.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 15, 2002, December 31, 2001 and December 31, 2000 was $14.17, $15.70 and $13.375, respectively.

The number of holders of record of the Company's Common Stock was 744 (and approximately 3,600 street name shareholders) as of February 15, 2002. There was one Class B Stockholder of record as of February 15, 2002.

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.

Since Berry Petroleum Company's formation in 1985, the Company has paid dividends on its Common Stock for eight consecutive semi-annual periods through September 1989 and for 49 consecutive quarters through December 31, 2001. 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, 2001, 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, 2001 were derived from the audited financial statements and the accompanying notes to those financial statements (in thousands, except per share, per BOE and % data):

	2001	2000	1999	1998	1997
Statement of Operations Data:					
Sales of oil and gas	$100,146	$118,801	$ 66,615	$ 39,858	$ 67,172
Sales of electricity	35,917	52,765	33,731	15,680	17,190
Operating costs - oil and gas production	40,281	44,837	27,829	18,272	22,589
Operating costs - electricity generation	35,506	50,566	27,930	15,236	17,008
General and administrative expenses (G&A)	7,174	7,754	6,269	3,975	5,907
Depreciation, depletion & amortization (DD&A)	16,520	14,030	12,294	10,080	10,138
Net income	21,938	37,183	18,006	3,879	19,260
Basic net income per share	1.00	1.69	.82	.18	.88
Weighted average number of shares outstanding	21,973	22,029	22,010	22,007	21,976
Balance Sheet Data:					
Working capital	$ 5,837	$ (1,154)	$ 8,435	$ 9,081	$ 11,499
Total assets	232,526	238,359	207,649	173,804	177,724
Long-term debt	25,000	25,000	52,000	30,000	32,000
Shareholders' equity	153,153	145,224	116,213	106,924	111,871
Cash dividends per share	.40	.40	.40	.40	.40
Operating Data:					
Cash flow from operations	35,433	65,934	24,809	19,924	31,401
Capital expenditures (excluding acquisitions)	14,895	25,253	9,122	6,981	18,597
Property/facility - acquisitions	2,273	3,182	33,605	2,991	-
Oil and gas producing operations (per BOE):					
Average sales price	$ 19.79	$ 21.72	$ 13.07	$ 9.05	$ 14.71
Average operating cost(1)	7.99	8.20	5.47	4.15	4.96
G&A	1.42	1.42	1.23	.90	1.30
Cash flow	10.38	12.10	6.37	4.00	8.45
DD&A	3.28	2.57	2.42	2.29	2.23
Operating income	$ 7.10	$ 9.53	$ 3.95	$ 1.71	$ 6.22
Production (BOE)	5,044	5,467	5,090	4,399	4,550
Production (Mwh)	456	764	728	448	446
Proved Reserves Information:					
Total BOE	102,855	107,361	112,541	92,609	101,043
Present value (PV10) of estimated future cash flow before income taxes	$356,556	$721,770	$714,555	$113,811	$376,459
Year-end average BOE price for PV10 purposes	14.18	20.63	19.41	7.05	12.19
Other:					
Return on average shareholders' equity	14.7%	28.5%	16.5%	3.5%	18.1%
Return on average total assets	8.7%	16.8%	9.0%	2.2%	10.9%
Total debt/total debt plus equity	14.0%	14.7%	30.9%	21.9%	22.2%
Year-end stock price	$ 15.70	$ 13.375	$ 15.125	$ 14.188	$ 17.438
Year-end market capitalization	$341,192	$294,699	$332,920	$312,247	$383,510

(1) Including monthly expenses in excess of monthly revenues from

cogeneration operations	$ 1.31	$ 0.53	$ -	$ 0.14	$ 0.48

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, 2001, 2000 and 1999 and the financial condition, liquidity and capital resources as of December 31, 2001 and 2000. 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 $21.9 million, or $1.00 per share, in 2001, down 41% from $37.2 million, or $1.69 per share, in 2000, but up 22% from $18 million, or $.82 per share in 1999. Income earned in 2001 represents the second highest income ever achieved by the Company, exceeded only by the $37.2 million earned in 2000. The decrease in income from 2000 was primarily related to lower crude oil prices and lower production which was a direct result of the suspension of steam operations in 2001 due to the California energy crisis and the writedown of electricity receivables from two of California's insolvent public utilities.

The following table presents certain operating data for the years ended December 31, 2001, 2000 and 1999:

	2001	2000	1999
Oil and Gas			
Net production - BOE/D	13,820	14,937	13,946
Per BOE:			
Average sales price	$19.79	$21.72	$13.07
Operating costs(1)	7.50	7.77	4.95
Production taxes	.49	.43	.52
Total operating costs	7.99	8.20	5.47
DD&A	3.28	2.57	2.42
G&A	1.42	1.42	1.23
Interest expense	.74	.58	.78
Electricity			
Electric power produced - megawatt (Mw) hrs/day	1,251	1,979	1,957
Average sales price/Mw	$78.68	$72.85	$47.22
Fuel gas cost/Mmbtu	5.76	4.95	2.74

(1) Including monthly expenses in excess of monthly revenues from cogeneration operations of $1.31, $0.53 and $0 in 2001, 2000 and 1999, respectively.

BOE/D - Barrels of oil equivalent per day

Operating income from oil and gas producing operations was $42.2 million in 2001, down from $60.3 million in 2000, but up from $26.8 million in 1999. The decrease from 2000 was primarily due to lower sales of oil and gas and higher DD&A, partially offset by lower operating costs. Sales of oil and gas were $100.1 million in 2001, down from $118.8 million in 2000, but higher than $66.6 million in 1999. The decrease from 2000 was related to both lower production and sales prices and the increase from 1999 was due to higher oil prices partially offset by slightly lower production. Production in 2001 at 13,820 BOE/D was 7% and 1% lower than 14,937 in 2000 and 13,946 in 1999, respectively. Production for 2001 peaked at approximately 16,000 BOE/D in the first quarter before the effects of the suspension of steaming operations took effect. The extremely high natural gas costs during the California energy crisis and the suspension of utility payments for cogeneration power made steaming uneconomic for several months in the first half of 2001. The Company was forced to curtail conventional steaming operations in late 2000 and suspend the majority of its cogeneration operations in February 2001 with the remaining turbine shut-in in early April. In June, the Company began increasing its steaming activities, with normal injection levels re-established in August. Due to the steam curtailment, crude oil production fell to a low of approximately 12,800 BOE/D before recovering to a level of approximately 14,000 BOE/D at year-end. The Company expects 2002 crude oil production levels to average approximately 15,000 BOE/D.

Oil prices for 2001 were quite strong until the aftermath of September 11 reduced worldwide demand for crude oil and refined products. The average price received/BOE in 2001 of $19.79 was only slightly lower than $21.72 in 2000 and was 51% higher than $13.07 received in 1999. Post September 11, crude oil prices fell $9/Bbl to a low of $11.00 for California heavy oil but subsequently rebounded to $13.25/Bbl at year-end and to $15.25 as of February 13, 2002.

Operating costs per barrel in 2001 were $7.99, down from $8.20 in 2000, but higher than $5.47 in 1999. The most significant factor in the reduction of operating costs from 2000 was the suspension of steaming operations. Not only was the cost of gas dramatically reduced, but other factors in the Company's cost structure, such as production rig cost, chemicals for water treating and other areas were greatly diminished or eliminated for the period in which steaming was suspended. Although the suspension was a positive factor in lowering operating costs in 2001, it did, of course, come at the cost of declining production levels. Other factors contributing to the decline in operating costs were the 3D project performed on the Company's Midway-Sunset properties in 2000, higher environmental remediation costs in 2000 and savings from facility consolidation projects on several of the Company's core properties in 2001. It should be pointed out that in the period of suspended cogeneration operations, it was necessary to purchase additional electricity from two California utilities at very high per unit costs which resulted in an increase in power costs of approximately $1.1 million over 2000 levels. The Company estimates that the operating cost per barrel in 2002 will average $7.00 to $8.00 given the current development plan and operating environment.

The Company has seen a drastic decline in electricity prices during 2001. Although the average price received for the Company's power was comparable at $.078/Kwh for both 2000 and 2001, the trend in electricity pricing is toward much lower prices which had a negative impact on the Company's steam costs in the fourth quarter of 2001 and will also affect 2002 costs and beyond. Although the Company has negotiated electricity sales contracts on its two Placerita turbines at attractive prices, the remaining electricity generated is sold on the open market which currently has been priced at just $.025/Kwh.

As the Company entered 2001, the California energy crisis was just unfolding. Two of the state's major utilities were experiencing extreme cash flow problems related to their inability to pass their cost to obtain electricity to retail and industrial customers. Therefore, in the early portion of 2001, these two utilities suspended payment for electric power produced by the Company under longstanding Standard Offer contracts. The

Company was forced to take actions to protect the liquidity of the Company. Prior to Pacific Gas and Electric Company's (PG&E) bankruptcy, the Company terminated its power purchase contracts with PG&E. The Bankruptcy Court confirmed these terminations and Berry paid $.2 million pursuant to the settlement and stipulation with PG&E. In June 2001, the Company entered into a contract with a creditworthy power marketer and re-established power production from its homebase cogeneration capacity. In September 2001, the Company assigned its past-due receivables for approximately 77% of the balance owed by PG&E which effectively ended the Company's direct involvement with PG&E's default.

The Company filed litigation against Edison and the California Independent System Operator (ISO) on May 2 and May 7, 2001 to recover non-payment for deliveries of electricity from November 2000 through March 2001 and to resolve other contractual matters. The lawsuits were ultimately coordinated with those of other "qualified facilities" and, on June 27, 2001, the Company and Edison entered into amendments with respect to its existing Power Purchase Agreements which became effective on July 18, 2001. The amendments provided for a standstill of litigation and other matters. On August 27, 2001, the Company entered into Implementing Agreements concerning these amendments requiring the suspension of legal proceedings during the agreed to "Standstill Period". The above agreements were approved by the Court on September 19, 2001. One of the two agreements will expire under its own terms in May 2002, at which time the Company will need to make other arrangements for the sale of the corresponding electricity production. The Standstill Period was extended by a further amendment on December 10, 2001 and a payment formula was established whereby Edison was to make payments, although there was no date identified. Additionally, Edison was required to make monthly payments in advance for power to be delivered and to make interest payments on the outstanding balance until the balance is paid or the amendments terminate. On March 1, 2002, Edison paid the Company $13.5 million, representing the total past-due amount plus interest. The Company will record pre-tax income of $4.2 million in the first quarter of 2002 related to this cash receipt.

At year-end the Company had no commodity hedges in place. In December, the Company terminated its crude oil and natural gas derivative contracts with Enron and recognized a net pre-tax loss on termination of these contracts of $1.5 million. The Company anticipates that it will enter into similar gas purchase hedges in the near future in an effort to manage its "spark spread" (the difference between the price received for the sale of electricity and the cost of natural gas) and lower its operating costs.

DD&A on a per barrel basis increased to $3.28, up from $2.57 in 2000 and $2.42 in 1999. The increase from prior years was primarily due to a higher depreciable basis resulting from the 2001 and 2000 development activity and facility improvements at the Company's cogeneration facilities and the amortization of the remaining capitalized costs related to the Standard Offer electricity sales contracts which were terminated in 2001. The Company expects DD&A to be slightly lower in 2002 compared to 2001.

General

G&A expenses in 2001 were $7.2 million, or $1.42 per BOE, down 8% from $7.8 million in 2000, but up 14% from $6.3 million in 1999. The decrease from 2000 was primarily the result of lower personnel costs, legal expenses and consulting charges. The Company expects similar G&A expenses in 2002 compared to 2001.

Interest expense increased in 2001 to $3.7 million from $3.2 million in 2000, but decreased from $4.0 million in 1999. To ensure liquidity, the Company drew down $45 million from its credit facility in early 2001 to compensate for the large unpaid receivables from electricity sales in late 2000 and the early months of 2001. The receivable for one of the two utilities was sold in the third quarter eliminating approximately half of the remaining receivable balance. These funds and internally generated funds were sufficient to pay off the $45 million drawdown by the end of the third quarter of 2001. The debt repayment along with much lower interest rates has resulted in lower interest costs incurred thus far in 2002 compared to the average rate experienced in 2001.

The Company experienced an effective income tax rate of 19.5% in 2001, down from 28% and 21% in 2000 and 1999, respectively. The lower 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 fourth 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 below 30% in 2002.

Financial Condition, Liquidity and Capital Resources

Working capital at December 31, 2001 was $5.8 million, up from ($1.2) million at December 31, 2000, but down from $8.4

million in 1999. Net cash provided by operations was $35.4 million, down 46% from the all-time record of $65.9 million achieved in 2000, but 43% higher than $24.8 million in 1999. The Company used these funds to pay for capital expenditures of $14.9 million, pay dividends of $8.8 million, acquire an interest in producing properties and drillable acreage of $2.3 million and increase the company's cash balance by $4.5 million to a healthy balance of $7.2 million at December 31, 2001. The Company's net debt (i.e., its outstanding long-term debt of $25 million less working capital) was $19.2 million.

The Company has a $150 million revolving bank facility with a banking group. As of December 31, 2001, approximately $118 million is available under the agreement after deducting the $25 million long-term debt and $6.7 million in outstanding Letters of Credit.

As of June 30, 2001, the Company was owed $15.0 million by Edison for power produced between November 2000 and March 2001. In the third quarter of 2001, $1.5 million of the total was received, leaving a remaining balance of $13.5 million as of December 31, 2001. Of this balance, $9.3 million was recorded as collectible receivables at December 31, 2001. On March 1, 2002, Edison paid the Company $13.5 million, representing the total amount due plus interest. The Company presently intends to use these funds to reduce its long-term debt of $25 million to approximately $12 million.

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.

The Company has budgeted $19.6 million in capital projects in 2002 consisting of the drilling of 52 Company operated wells on its core California properties, 11 of which will be horizontal, and 33 non-operated (gross wells) in the South Joe Creek field in Wyoming. The development program will also include 31 remedial jobs and other facility improvements of $6.4 million all at the Company's core California properties.

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 2001.

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 in 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 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.

The Company makes certain estimates, 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, net of salvage value, of its oil and gas properties and equipment. The Company reviews its estimate of the future obligation periodically and accrues the estimated obligation monthly based on the units of production method.

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.

Recent Accounting Developments

In July 2001, the Financial Accounting Standards Boards (FASB) issued SFAS No. 141, "Business Combinations," which supersedes Accounting Principles Board Opinion (APB) No. 16, "Business Combinations." This Statement requires that all business combinations be accounted for by the purchase method, establishes specific criteria for the recognition of intangible assets separately from goodwill and requires unallocated negative goodwill to be written off immediately as an extraordinary gain. The provisions of the Statement apply to business combinations initiated after June 30, 2001. For business combinations accounted for using the purchase method before July 1, 2001, the provisions of this Statement will be effective in the first quarter of 2002. The Company anticipates that the impact of this new standard will have an immaterial impact on the financial statements taken as a whole.

In July 2001, the Financial Accounting Standard Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 142, "Goodwill and Other Intangible Assets," which supersedes the Accounting Principles Board (APB) Opinion No. 17, "Intangible Assets." This Statement addresses the accounting and reporting of goodwill and other intangible assets subsequent to their acquisition. The Statement also provides specific guidance on testing goodwill and intangible assets for impairment. SFAS No. 142 provides that (i) goodwill and indefinite-lived intangible assets will no longer be amortized, (ii) impairment will be measured using various valuation techniques based on discounted cash flows, (iii) goodwill will be tested for impairment at least annually at the reporting unit level, (iv) intangible assets deemed to have an indefinite life will be tested for impairment at least annually and (v) intangible assets with finite lives will be amortized over their useful lives. All provisions of this Statement will be effective in the first quarter of 2002. The Company anticipates that the impact of this new standard will have an immaterial impact on the financial statements taken as a whole.

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. The Company is in the process of determining the impact of this standard on the Company's financial results when effective.

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 will be effective in the first quarter of 2002. The Company anticipates that the impact of this new standard will have an immaterial impact on the financial statements taken as a whole.

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 approximately $5.5 million change in annual revenues. The Company periodically enters into hedge contracts to manage the oil price risk. The Company had no crude oil hedges in place at December 31, 2001. However, the Company has entered into oil price protection hedges in 2002 for a one-year period beginning April 1, 2002 on a total of 5,000 BPD. Based on WTI pricing, the hedges have a floor of approximately $20.00/Bbl and a ceiling of approximately $24.00/Bbl. 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 March 31, 2003 for over 80% of its crude oil production which is priced at the higher of (1) local field posting plus a bonus, (2)WTI minus a fixed differential or (3)a fixed percentage of WTI.

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). This was an extremely difficult goal to achieve during 2001 primarily due our early electrical contract terminations arising out of the utility purchasers' default and the volatility in the electrical market and in natural gas prices. 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 equates to a change of approximately $1.0 million in operating costs.

The Company has a long-term electricity sales contract in place 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. The Company is a party to another electricity sales contract for approximately 19 Mwh that is based on a short-run avoided cost (SRAC) pricing mechanism. This provides the Company an electricity price that is directly related to the cost of natural gas. However, this contract terminates in May 2002, whereupon this volume may be sold on the open market. The remainder of the electricity is sold primarily on the open market to a creditworthy customer. As the electricity market stabilizes in California, the Company anticipates entering into longer-term sales contracts for its electricity. The Company was able to enter into a four-month sales contract through June 30, 2002 under which the Company will deliver 25 Mwh of electricity, plus a cash payment, in exchange for a sufficient volume of natural gas needed to generate the 25 Mwh of electricity to fulfill the contract, thereby protecting the spark spread on this volume. The Company is pursuing longer-term arrangements on the sale of its electricity and may enter into additional hedges on its natural gas purchases to seek to improve the spark spread related to these non-utility volumes.

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, gas transportation availability, the non-existence of a liquid marketplace for electricity purchases and sales within California, competition, environmental risks, litigation uncertainties, drilling, development and operating risks, uncertainties about the estimates of reserves, the prices of goods and services, the availability of drilling rigs and other support services, legislative, California Public Utilities Commission, Federal Energy Regulatory Commission, 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, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001 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/ PRICEWATERHOUSECOOPERS LLP

February 11, 2002, except as to Note 14,
which is as of March 1, 2002

Los Angeles, California

BERRY PETROLEUM COMPANY
Balance Sheets
December 31, 2001 and 2000
(In Thousands, Except Share Information)

	2001	2000
ASSETS		
Current assets:		
Cash and cash equivalents	$ 7,238	$ 2,731
Short-term investments available for sale	594	582
Accounts receivable	17,577	26,420
Prepaid expenses and other	2,792	5,190
Total current assets	28,201	34,923
Oil and gas properties (successful efforts basis), buildings and equipment, net	203,413	201,643
Other assets	912	1,793
	$ 232,526	$ 238,359
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 11,197	$ 28,678
Accrued liabilities	7,089	2,288
Federal and state income taxes payable	4,078	5,110
Total current liabilities	22,364	36,076
Long-term debt	25,000	25,000
Deferred income taxes	32,009	32,059
Commitments and contingencies (Note 9)	-	-
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; 20,833,094 shares issued and outstanding (21,134,667 in 2000)	208	211
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	48,905	53,686
Accumulated other comprehensive income	-	441
Retained earnings	104,031	90,877
Total shareholders' equity	153,153	145,224
	$ 232,526	$ 238,359

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

BERRY PETROLEUM COMPANY
Statements of Operations
Years ended December 31, 2001, 2000 and 1999
(In Thousands, Except Per Share Data)

	2001	2000	1999
Revenues:			
Sales of oil and gas	$ 100,146	$ 118,801	$ 66,615
Sales of electricity	35,917	52,765	33,731
Interest and dividend income	2,150	447	674
Other income	328	36	186
	138,541	172,049	101,206
Expenses:			
Operating costs - oil and gas production	40,281	44,837	27,829
Operating costs - electricity generation	35,506	50,566	27,930
Depreciation, depletion & amortization	16,520	14,030	12,294
General and administrative	7,174	7,754	6,269
Interest expense	3,719	3,186	3,973
Write-off of electricity receivables	6,645	-	-
Termination of derivative contracts	1,458	-	-
	111,303	120,373	78,295
Income before income taxes	27,238	51,676	22,911
Provision for income taxes	5,300	14,493	4,905
Net income	$ 21,938	$ 37,183	$ 18,006
Basic net income per share	$ 1.00	$ 1.69	$ .82
Diluted net income per share	$ .99	$ 1.67	$ .82
Weighted average number of shares of capital stock outstanding (used to calculate basic net income per share)	21,973	22,029	22,010
Effect of dilutive securities:			
Employee stock options	113	185	32
Other	24	26	7
Weighted average number of shares of capital stock used to calculate diluted net income per share	22,110	22,240	22,049

Statements of Comprehensive Income
Years Ended December 31, 2001, 2000 and 1999
(In Thousands)

	2001	2000	1999
Net income	$ 21,938	$ 37,183	$ 18,006
(Realized) unrealized gains on derivatives	(441)	441	-
Comprehensive income	$ 21,497	$ 37,624	$ 18,006

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

BERRY PETROLEUM COMPANY
Statements of Shareholders' Equity
Years Ended December 31, 2001, 2000 and 1999
(In Thousands, Except Per Share Data)

	Class A	Class B	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income	Shareholder's Equity
Balances at January 1, 1999	$ 211	$ 9	$ 53,400	$ 53,304	$ -	$ 106,924
Stock options exercised	-	-	2	-	-	2
Deferred director fees - stock compensation	-	-	85	-	-	85
Cash dividends declared - $.40 per share	-	-	-	(8,804)	-	(8,804)
Net income	-	-	-	18,006	-	18,006
Balances at December 31, 1999	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)
Realized gains on derivatives	-	-	-	-	(441)	(441)
Net income	-	-	-	21,938	-	21,938
Balances at December 31, 2001	$ 208	$ 9	$ 48,905	$104,031	$ -	$ 153,153

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

BERRY PETROLEUM COMPANY
Statements of Cash Flows
Years Ended December 31, 2001, 2000 and 1999
(In Thousands)

	2001	2000	1999
Cash flows from operating activities:			
Net income	$ 21,938	$ 37,183	$ 18,006
Depreciation, depletion and amortization	16,520	14,030	12,294
(Decrease) increase in deferred income tax liability	(50)	3,147	263
Other, net	(505)	249	(208)
Net working capital provided by operating activities	37,903	54,609	30,355
Decrease (increase) in current assets other than cash, cash equivalents and short-term investments	11,241	(14,227)	(7,839)
(Decrease) increase in current liabilities other than notes payable	(13,711)	25,552	2,293
Net cash provided by operating activities	35,433	65,934	24,809
Cash flows from investing activities:			
Capital expenditures, excluding property acquisitions	(14,895)	(25,253)	(9,122)
Property/facility acquisitions	(2,273)	(3,182)	(33,605)
Proceeds from sale of assets	151	49	21
Purchase of short-term investments	(1,183)	(584)	(611)
Maturities of short-term investments	1,171	600	725
Contract purchases	-	-	(1,028)
Net cash used in investing activities	(17,029)	(28,370)	(43,620)
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	45,000	1,000	35,000
Payment of long-term debt	(45,000)	(28,000)	(13,000)
Dividends paid	(8,784)	(8,812)	(8,804)
Share repurchase program	(5,112)	-	-
Other, net	(1)	(1)	(463)
Net cash (used in) provided by financing activities	(13,897)	(35,813)	12,733
Net increase (decrease) in cash and cash equivalents	4,507	1,751	(6,078)
Cash and cash equivalents at beginning of year	2,731	980	7,058
Cash and cash equivalents at end of year	$ 7,238	$ 2,731	$ 980
Supplemental disclosures of cash flow information:			
Interest paid	$ 3,532	$ 2,999	$ 4,546
Income taxes paid	$ 5,635	$ 9,712	$ 4,079

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

1. General

The Company is an independent energy company engaged in the production, development, acquisition, exploitation and exploration of crude oil and natural gas. Substantially all of the Company's oil and gas reserves are located in California. Approximately 99% of the Company's production is heavy crude oil, which is principally sold to other oil companies, pipeline companies or refiners. The Company has invested in cogeneration facilities which provides steam required for the extraction of heavy oil and which generates 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. The costs of carrying and retaining unproved properties are also expensed when incurred.

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. The estimated costs, net of salvage value, of plugging and abandoning oil and gas wells and related facilities are accrued using the units-of-production method and are taken into account in determining DD&A expense. 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. 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.

2. 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. Liabilities 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" and "Operating costs -electricity generation." Natural gas transportation costs categories were $1.2 million, $1.6 million and $1.4 million for 2001, 2000 and 1999, respectively.

2. 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 plans. The supplemental disclosure requirements of SFAS No. 123 and further information related to the Company's stock option plans are presented in Note 11 to the Company's financial statements.

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.

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 July 2001, the Financial Accounting Standards Boards (FASB) issued SFAS No. 141, "Business Combinations," which supersedes Accounting Principles Board Opinion (APB) No. 16, "Business Combinations." This Statement requires that all business combinations be accounted for by the purchase method, establishes specific criteria for the recognition of intangible assets separately from goodwill and requires unallocated negative goodwill to be written off immediately as an extraordinary gain. The provisions of the Statement apply to business combinations initiated after June 30, 2001. For business combinations accounted for using the purchase method before July 1, 2001, the provisions of this Statement will be effective in the first quarter of 2002. The Company anticipates that the impact of this new standard will have an immaterial impact on the financial statements taken as a whole.

In July 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets," which supersedes the APB Opinion No. 17, "Intangible Assets." This Statement addresses the accounting and reporting of goodwill and other intangible assets subsequent to their acquisition. The Statement also provides specific guidance on testing goodwill and intangible assets for impairment. SFAS No. 142 provides that (i) goodwill and indefinite-lived intangible assets will no longer be amortized, (ii) impairment will be measured using various valuation techniques based on discounted cash flows, (iii) goodwill will be tested for impairment at least annually at the reporting unit level, (iv) intangible assets deemed to have an indefinite life will be tested for impairment at least annually and (v) intangible assets with finite lives will be amortized over their useful lives. All provisions of this Statement will be effective in the first quarter of 2002. The Company anticipates that the impact of this new standard will have an immaterial impact on the financial statements taken as a whole.

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

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

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. The Company is in the process of determining the impact of this standard on the Company's financial results when effective.

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 will be effective in the first quarter of 2002. The Company anticipates that the impact of this new standard will have an immaterial impact on the financial statements taken as a whole.

Reclassifications

Certain reclassifications have been made to the 2000 and 1999 financial statements to conform with the 2001 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 $6.4 million and $2.3 million at December 31, 2001 and 2000, respectively, are stated at cost, which approximates market.

The Company's short-term investments available for sale at December 31, 2001 and 2000 consist of a United States treasury note that matures in less than one year. The carrying value of the Company's long-term debt is assumed to approximate its fair value since it is carried at current interest rates. For the three years ended December 31, 2001, 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 them as to the value of the contracts as of termination. Based on the agreed value, the Company recorded a liability of $1.3 million which will be remitted upon the approval by the Enron bankruptcy judge.

To protect the Company's revenues from potential price declines, the Company entered into bracketed zero cost collar hedge contracts with California refiners covering 3,000 BPD to 6,500 BPD of its crude oil production during 2000 and 1999, with the most recent contracts expiring on December 31, 2000. The Company recorded losses of $7.1 million and $2.6 million in 2000 and 1999, respectively, which were reported in "Sales of oil and gas" in the Company's financial statements.

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

In December 2000, the Company entered into a series of derivative contracts to reduce exposure to unfavorable changes in natural gas prices. These contracts limited the price the Company paid for 4,500 Mmbtu/day of natural gas for the three-month period ending March 31, 2001. In the first quarter of 2001, the Company earned $1.4 million pre-tax from these hedges which was recorded as a reduction to "Operating costs - electricity generation".

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, with a major California refiner whereby the Company sells in excess of 80% of its production under a negotiated pricing mechanism. The agreement is based on a monthly determination of the highest price from any of (1) local field posted price plus a fixed bonus, (2) WTI minus a fixed differential or (3) a fixed percentage of WTI. 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, 2001, 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. However, see Note 14.

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, 2001, the Company has not incurred losses related to these investments.

The following summarizes the accounts receivable balances at December 31, 2001 and 2000 and sales activity with significant customers for each of the years ended December 31, 2001, 2000 and 1999 (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.

	Accounts Receivable		Sales		
	December 31,	December 31,	For the Year Ended December,31		
Customer	2001	2000	2001	2000	1999
Oil & Gas Sales:					
A	$ 4,754	$ 9,699	$ 83,336	$ 87,613	$ 30,289
B	870	1,246	14,962	18,000	6,262
C	260	391	4,858	5,499	7,890
D	5	24	157	12,390	15,064
E	-	-	-	13,080	11,467
	$ 5,889	$ 11,360	$ 103,313	$ 136,582	$ 70,972
Electricity Sales:					
F	$ 9,873	$ 5,625	$ 21,257	$ 23,124	$ 16,013
G	-	8,660	6,859	26,769	15,603
H	812	-	6,279	-	-

$ 10,685	$ 14,285	$ 34,395	$ 49,893	$ 31,616
=======	=======	=======	=======	=======

5. Oil and Gas Properties, Buildings and Equipment

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

	2001	2000
Oil and gas:		
Proved properties:		
Producing properties, including intangible drilling costs	$ 168,930	$ 160,484
Lease and well equipment	146,393	138,007
	315,323	298,491
Less accumulated depreciation, depletion and amortization	113,617	98,925
	201,706	199,566
Commercial and other:		
Land	173	173
Buildings and improvements	4,086	4,086
Machinery and equipment	3,634	4,553
	7,893	8,812
Less accumulated depreciation	6,186	6,735
	1,707	2,077
	$ 203,413	$ 201,643

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

	2001	2000	1999
Acquisition of properties/facilities(1)	$ 2,273	$ 3,204	$ 34,167
Development	15,875	26,145	9,195
	$ 18,148	$ 29,349	$ 43,362

(1) Includes cogeneration facility costs and certain closing and consultant costs related to the acquisitions, but excluding electricity contract costs.

The Company acquired a 15.8% working interest in coalbed methane gas properties in Wyoming for $2.2 million and a producing property adjacent to Berry's core Midway-Sunset properties for $.1 million during the current year. Approximately .5 million equivalent barrels of proved reserves were added by these acquisition. The 2000 acquisition included the Castruccio property at the Company's Placerita area which included 1.5 million barrels of reserves and the 1999 acquisition included the Placerita field acquisition for $35 million which added approximately 20 million barrels to the Company's reserve inventory.

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):

	2001	2000	1999
Sales to unaffiliated parties	$100,146	$118,801	$ 66,615
Production costs	(40,281)	(46,789)	(28,697)
Depreciation, depletion and amortization	(16,175)	(13,712)	(12,020)
	43,690	58,300	25,898
Income tax expenses	(10,740)	(15,668)	(5,856)
Results of operations from producing and exploration activities	$ 32,950	$ 42,632	$ 20,042

6. Debt Obligations

	2001	2000	1999
Long-term debt for the years ended December 31 (in thousands):			
Revolving bank facility	$ 25,000	$ 25,000	$ 52,000

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 five-year unsecured bullet loan. At December 31, 2001 and 2000, the Company had $25 and $25 million, respectively, outstanding under the Agreement. In addition to the $25 million in borrowings under the Agreement, the Company has $6.7 million of outstanding Letters of Credit and the remaining credit available under the Agreement is therefore, $118.3 million at December 31, 2001. 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 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, 2001 was 4.92%. 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 authorizes the purchase of 100,000 shares of Berry Petroleum Company Class A Common Stock until November 8, 2003 at $14.06 per share. All the warrants are currently outstanding and the underlying shares will not be registered under the Securities Act of 1933.

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.

The Company issued 6,529, 21,325 and 2,745 shares in 2001, 2000 and 1999, respectively, through its stock option plan.

At December 31, 2001, 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):

	2001	2000	1999
Current:			
Federal	$ 3,108	$ 10,336	$ 2,661
State	1,119	3,165	928
	4,227	13,501	3,589
Deferred:			
Federal	1,755	1,787	1,979
State	(682)	(795)	(663)
	1,073	992	1,316
Total	$ 5,300	$ 14,493	$ 4,905

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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):

	2001	2000	1999
Deferred tax asset			
Federal benefit of state taxes taxes	$ 392	$ 871	$ 392
Credit/deduction carryforwards	11,599	7,761	4,434
Other, net	579	1,261	367
	12,570	9,893	5,193
Deferred tax liability			
Depreciation and depletion	(43,608)	(39,894)	(33,452)
Other, net	210	246	(504)
	(43,398)	(39,648)	(33,956)
Net deferred tax liability	$(30,828)	$(29,755)	$(28,763)

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

	2001	2000	1999
Tax computed at statutory federal rate	35.0%	35.0%	35.0%
State income taxes, net of federal benefit	1.0	2.3	.3
Tax credits	(15.7)	(11.0)	(12.9)
Other	(.8)	1.8	(1.0)
Effective tax rate	19.5%	28.1%	21.4%

The Company has approximately $9.0 million of federal and $5.8 million of state (California) enhanced oil recovery (EOR) tax credit carryforwards available to reduce future income taxes. Total EOR credits of $.2 million, $1.1 million, $6.2 million and $7.3 million will expire in 2013, 2014, 2015 and 2016, 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 as follows:

Year ending December 31,	
2002	$ 366,920
2003	440,305
2004	440,305
2005	440,305
2006	366,920
Total	$2,054,755

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 (the 1994 Plan) and approved by the shareholders in May 1998. The 1994 Plan provides for the granting of stock options to purchase up to an aggregate of 2,000,000 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.

On December 7, 2001 and December 1, 2000, 199,500 and 262,000 options, respectively, were issued to certain key employees at an exercise price of $16.30 and $15.6875 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. No employee options were issued in 1999. The 1994 Plan also allows for option grants to the Board of Directors under a formula plan whereby all non-employee Directors are eligible to 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, 40,000, 40,000 and 40,000 options, respectively, were issued on December 2, 2001, 2000 and 1999, (5,000 options to each of the non-employee Directors each year) at an exercise price of $15.45, $15.6875 and $14.0625 per share, respectively.

11. Stock Option Plan (cont'd)

The Company applies APB No. 25 and related interpretations in accounting for its stock option plan. The options issued per the 1994 Plan were issued at market price. Compensation recognized related to the 1994 Plan was $0 million in 2001, $.3 million in 2000 and $0 in 1999.

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:

	2001	2000	1999
Yield	2.72%	2.77%	2.75%
Expected option life - years	7.5	4.5	4.0
Volatility	38.71%	36.53%	34.24%
Risk-free interest rate	4.65%	4.85%	6.33%

Had compensation cost for the 1994 Plan been based upon the fair value at the grant dates for awards under this plan consistent with the method of SFAS No. 123, the Company's net income and earnings per share would have been reduced to the pro forma amounts indicated below (in thousands, except per share data):

	2001	2000	1999
Net income as reported	$21,938	$37,183	$18,006
Pro forma	21,197	36,581	17,343
Net income per share as reported	1.00	1.69	.82
Pro forma	.99	1.66	.79

The following is a summary of stock-based compensation activity for the years 2001, 2000 and 1999.

	2001 Options	2000 Options	1999 Options
Balance outstanding, January 1	1,407,837	1,220,630	1,227,630
Granted	239,500	302,000	40,000
Exercised	(65,125)	(114,793)	(22,000)
Canceled/expired	(107,250)	-	(25,000)
Balance outstanding, December 31	1,474,962	1,407,837	1,220,630
Balance exercisable at December 31	1,010,712	872,587	697,630
Available for future grant	232,550	364,800	666,800
Exercise price-range	$ 14.40 to 16.96	$ 16.4375 to 19.00	$ 14.125 to 14.25
Weighted average remaining contractual life (years)	7	8	8
Weighted average fair value per option granted during the year	$ 5.87	$ 4.62	$ 5.14

11. Stock Option Plan (cont'd)

Weighted average option exercise price information for the years 2001, 2000 and 1999 as follows:

	2001	2000	1999
Outstanding at January 1	$ 14.58	$ 14.15	$ 14.18
Granted during the year	16.16	15.69	14.06
Exercised during the year	13.12	12.91	12.40
Expired during the year	16.01	-	16.69
Outstanding at December 31	14.80	14.58	14.15
Exercisable at December 31	14.55	14.50	14.21

12. Retirement Plan

The Company sponsors a defined contribution retirement or thrift plan (401(k) Plan) to assist all 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 2001, $.5 million in 2000 and $.3 million in 1999.

13. Quarterly Financial Data (unaudited)

The following is a tabulation of unaudited quarterly operating results for 2001 and 2000 (in thousands, except per share data):

2001	Operating Revenues	Gross Profit	Net Income	Basic net Income Per Share	Diluted net Income Per Share
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
2000					
First Quarter	$ 35,136	$ 14,525	$ 8,859	$ .40	$ .40
Second Quarter	36,446	14,187	8,894	.40	.40
Third Quarter	45,939	15,096	9,578	.43	.43
Fourth Quarter	54,045	16,450	9,852	.45	.44
	$171,566	$ 60,258	$ 37,183	$1.69	$1.67

14. Subsequent Events

At December 31, 2001, the Company was owed $13.5 million by Edison for past due electricity sales. Of this amount, $9.3 million was recorded as a receivable. On March 1, 2002, the Company was paid the total amount due the Company of $13.5 million plus interest. The Company will record $4.2 million in pre-tax income in the first quarter of 2002 due to this collection.

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, 2001, 2000 and 1999. 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, 2001, 2000 and 1999, and changes in such quantities during each of the years then ended were as follows (in thousands):

	2001		2000		1999	
	Oil Mbbls	Gas Mmcf	Oil Mbbls	Gas Mmcf	Oil Mbbls	Gas Mmcf
Proved developed and undeveloped reserves:						
Beginning of year	106,664	4,184	111,888	3,920	91,933	4,060
Revision of previous estimates	33	153	(1,284)	463	3,126	40
Production	(4,996)	(288)	(5,434)	(199)	(5,060)	(180)
Purchase of reserves in place	-	2,877	1,494	-	21,889	-
End of year	101,701	6,926	106,664	4,184	111,888	3,920
Proved developed reserves:						
Beginning of year	81,132	1,635	86,717	1,371	83,532	1,604
End of year	79,317	3,518	81,132	1,635	86,717	1,371

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):

	2001	2000	1999
Future cash inflows	$1,452,946	$2,268,932	$2,208,964
Future production and development costs	(699,505)	(653,808)	(647,720)
Future income tax expenses	(184,064)	(512,012)	(502,951)
Future net cash flows	569,377	1,103,112	1,058,293
10% annual discount for estimated timing of cash flows	(289,036)	(599,530)	(561,811)
Standardized measure of discounted future net cash flows	$ 280,341	$ 503,582	$ 496,482
Pre-tax standardized measure of discounted future net cash flows	$ 356,556	$ 721,770	$ 714,555
Average sales prices at December 31:			
Oil ($/Bbl)	$ 14.18	$ 20.63	$ 19.41
Gas ($/Mcf)	$ 1.98	$ 10.94	$ 2.11

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

	2001	2000	1999
Standardized measure - beginning of year	$ 503,582	$ 496,482	$ 106,517
Sales of oil and gas produced, net of of production costs	(59,865)	(72,358)	(44,587)
Revisions to estimates of proved reserves:			
Net changes in sales prices and production costs	(407,519)	98,744	440,729
Revisions of previous quantity estimates	230	(9,295)	20,919
Change in estimated future development costs	48,689	(78,328)	(24,709)
Purchases of reserves in place	2,606	14,135	169,147
Development costs incurred during the period	14,895	25,253	9,122
Accretion of discount	72,177	71,455	11,381
Income taxes	135,792	(3,929)	(203,514)
Other	(30,246)	(38,577)	11,477
Net increase (decrease)	(223,241)	7,100	389,965
Standardized measure - end of year	$ 280,341	$ 503,582	$ 496,482

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 and Executive Officers report to the Securities and Exchange Commission changes in their beneficial ownership of Berry 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 that all Section 16(a) filing requirements were complied with.

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. 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.

Item 14. Exhibits, Financial Statement Schedules and Reports on Form 8-K (cont'd)

B. Reports on Form 8-K

None

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	46
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)	
10.6*	Warrant Certificate dated November 14, 1996, by and between Registrant and Tannehill Oil Company (filed as Exhibit 10.16 in Registrant's Form 10-K filed on March 21, 1997, File No. 1-9735)	
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)	

Exhibits (cont'd)

Exhibit No.	Description of Exhibit	Page
10.8*	Amended and Restated 1994 Stock Option Plan (filed as Exhibit 10.13 in Registrant's Form 10-K filed on March 16, 1999, File No. 1-9735)	
23.1	Consent of PricewaterhouseCoopers LLP	47
23.2	Consent of DeGolyer and MacNaughton	48
99.1	Undertaking for Form S-8 Registration Statements	49
99.2*	Form of Indemnity Agreement of Registrant (filed as Exhibit 28.2 in Registrant's Registration Statement on Form S-4 filed on April 7, 1987, File No. 33-13240)	
99.3*	Form of "B" Group Trust (filed as Exhibit 28.3 to Amendment No. 1 to Registrant's Registration Statement on Form S-4 filed on May 22, 1987, File No. 33-13240)	

* Incorporated by reference

Pursuant to 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 1, 2002.

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 1, 2002
/s/ William F. Berry William F. Berry	Director	March 1, 2002
/s/ Ralph B. Busch, III Ralph B. Busch, III	Director	March 1, 2002
/s/ William E. Bush, Jr. William E. Bush, Jr.	Director	March 1, 2002
/s/ J. Herbert Gaul, Jr. J. Herbert Gaul, Jr.	Director	March 1, 2002
/s/ John A. Hagg John A. Hagg	Director	March 1, 2002
/s/ Thomas J. Jamieson Thomas J. Jamieson	Director	March 1, 2002
/s/ Roger G. Martin Roger G. Martin	Director	March 1, 2002
/s/ Martin H. Young, Jr. Martin H. Young, Jr.	Director	March 1, 2002

DESCRIPTION OF THE SHORT-TERM CASH INCENTIVE PLAN (BONUS)

Annual cash incentive awards, which are designed to provide short-term performance incentives, are made to executives and other employees to recognize and reward corporate and individual performance. The plan in effect provides an annual incentive fund of up to 3.5% of the Company's annual net income, with certain adjustments, for executives and other employees involved in decision-making roles which effect the Company's growth and profitability goals.

Annually, Management and the Board will set specific targets to be achieved which will determine the cash payout as a whole and then to each eligible employee based on a formula. There shall be specific targets established for each of the following: production volume, reserve replacement, and non-steam operating cost. The Board retains the flexibility to adjust various items to assure compliance with the intent of the plans. All annual cash bonuses are approved by the Compensation Committee and by the Board of Directors.

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

We consent to the incorporation by reference in the registration statements of Berry Petroleum Company on Form S-8 (File Nos. 333-62799, 333-62871 and 333-62873) of our report dated February 11, 2002, except as to Note 14, which is as of March 1, 2002, on our audits of the financial statements of Berry Petroleum Company as of December 31, 2001 and 2000 and for the three years in the period ended December 31, 2001, which report is included in this Annual Report on Form 10-K.

March 11, 2002
Los Angeles, California

EXHIBIT 23.1

February 27, 2002

Berry Petroleum Company
P.O. Bin X
Taft, California 93268

Gentlemen:

In connection with the Annual Report on Form 10-K for the fiscal year ended December 31, 2001, (the Annual Report) of Berry Petroleum Company (the Company), we hereby consent to (i) the use of and reference to 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; our report dated February 16, 2000, entitled "Appraisal Report, as of December 31, 1999, 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 "Report"), 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 Statements on Form S-8 (No. 333-62799, 333-62871 and 333-62873):

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