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, 1995
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)

28700 Hovey Hills Road
Taft, California 93268
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code: (805) 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 March 4, 1996, the registrant had 21,033,055 shares of Class A Common Stock outstanding and the aggregate market value of the voting stock held by nonaffiliates was approximately $112,778,000. This calculation is based on the closing price of the shares on the New York Stock Exchange on March 4, 1996 of $9.625. The registrant also had 898,892 shares of Class B Stock outstanding on March 4, 1996, 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.

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Part I

Items 1 and 2. Business and Properties

Introduction

Berry Petroleum Company ("Berry" or "Company"), is an independent energy company engaged in the business of acquisition, exploration, exploitation, development, production and marketing of crude oil and natural gas. The Company was incorporated in Delaware in 1985 and has been a publicly held company since 1987. Berry's principal reserves and producing properties are located in Kern County and Ventura County, California. Information contained in this report on Form 10-K reflects the business of the Company during the year ended December 31, 1995. The Company's corporate headquarters are located on its Berry and Ewing lease in the southern portion of the Midway-Sunset field, and management believes the current facilities are adequate.

The Company's mission is to enhance shareholder value and achieve real asset growth. To achieve this, Berry's corporate strategy is to acquire primarily proved reserves with exploitation potential and to increase its proved reserves and production through further development of its existing properties by application of enhanced oil recovery (EOR) methods, advanced reservoir management and developmental drilling. All of the Company's reserves are located in the United States, and the Company continues to focus on opportunities in California and several select basins in the United States. While the Company has substantial working capital available for acquisitions, the Company will, as necessary, consider long-term debt or issuance of capital stock to finance future purchases.

Approximately 89% of the Company's proved reserves are located in the Midway-Sunset field in the San Joaquin Valley in California. The majority of these reserves are on properties owned in fee. Net production from this field in 1995 was 3.0 million barrels of oil equivalent (BOE) or 87% of the Company's total 1995 BOE production. The Midway-Sunset field contains predominantly heavy crude oil (under 20 degrees API gravity), the production of which depends substantially on steam injection. Berry utilizes primary, cyclic steaming and steam flooding recovery methods in this field. Production from the Montalvo field in Ventura County, California, which represents approximately 8% of the proved reserves, utilizes primary recovery methods.

Berry operates all of its principal oil producing properties. 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 L.A.C.T. (Lease Automatic Custody Transfer) facilities and transferred into crude oil pipelines owned by other oil companies.

Revenues

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

	1995	1994	1993
Sales of oil and gas	89%	95%	97%
Interest and other income	11%	5%	3%

See Berry's Statements of Operations and accompanying Notes thereto.

Marketing

The Company believes the market for its crude oil differs substantially from the oil market in the remainder of the country. Two key factors are responsible for lower crude prices in California versus the Mid-Continent. The first is that the Company's crude oil is primarily lower gravity crude oil and must be heated or blended for transport to refineries. In general, lower gravity crude oil results in lower yields of light products, such as gasoline and kerosene, in low conversion refineries. Additional processing, such as coking and catalytic cracking, increases light product yields, but at a higher capital cost per barrel of crude oil refined. The refiner or crude oil buyer generally pays lower prices for such crude oil, as reflected in lower posted and spot prices. The second factor, which may become less of a factor now that Congress passed and the President signed Senate Bill S.395 to allow the export of Alaskan North Slope (ANS) crude oil to foreign countries, was that all ANS crude oil production was required to go to or by the West Coast which reduced the price of both ANS and California crude oil. This federally mandated policy prevented free market prices on the West Coast, making California heavy crude price variations inconsistent with prevailing changes in market prices in other parts of the country. The Company believes the repeal of the ban of ANS exports may allow the Company and other West Coast producers to receive a fair market price for their crude oil. In addition, increased refining capacity of heavy crude oil has strengthened prices of heavy crude oil on the West Coast.

To provide additional market flexibility, the Company owns a blending facility located near its homebase properties. The Company suspended the blending operations in December 1993 due to the high cost of natural gasoline, the improved demand for the Company's 13 degree heavy crude oil, and the narrowing margin between the posted price of the blended crude oil and the heavy crude oil. Up to approximately 5,000 barrels per day of the Company's heavy crude oil can be blended with lighter crude oils and natural gasolines to produce a blended crude oil of approximately 27 degree API gravity. At times, this blending operation may allow the Company to improve the profit margin on the sale of its heavy crude oil. Blending also allows the Company the option to ship through common carrier pipelines and sell directly to refiners in the Los Angeles basin, the San Francisco Bay area and the Mid-Continent. No blending occurred during 1995 or 1994. The Company has the ability to resume blending operations if warranted by market conditions.

Environmental and Other Regulations

The operations of Berry are affected in varying degrees by federal, state, regional and local laws and regulations, including laws governing allowable rates of production, well spacing, air emissions, water discharges, endangered species, marketing, pricing, taxes and other laws relating to the petroleum industry. Berry is further affected by changes in such laws and by constantly changing administrative regulations.

Berry, as an owner and operator of oil and gas properties, is subject to various federal, state, regional and local laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liabilities on the owner or the lessee in the case of leased properties for the cost of pollution clean-up resulting from operations, subject the owner or lessee to liability for pollution damages, require suspension or cessation of operations in affected areas, and impose restrictions on the injection of liquids into subsurface aquifers that may contaminate groundwater. Such regulation has increased the length of time and cost of planning, designing, drilling, installing, operating and abandoning the Company's oil and gas wells and other treating facilities.

The Company estimates that it spends approximately $.3 million on technical and managerial time annually to comply with environmental regulations. In addition, the Company spent approximately $.5 million for capital projects, repairs and maintenance, and permits related to environmental control facilities in 1995 and anticipates spending approximately $.5 million for similar expenditures in 1996, with additional expenditures required in future years. The Company believes these are necessary business costs in the domestic oil and gas industry. Although environmental requirements do have a substantial

impact upon the energy industry, generally these requirements do not appear to affect Berry to any greater or lesser extent than other companies in California and in the domestic industry as a whole. In most cases, foreign produced crude oil enjoys a competitive advantage since foreign environmental regulations of oil producing regions are not nearly as stringent or comprehensive as in the United States and particularly California.

Berry's properties in the Montalvo field have greater environmental risks due to their location near the Pacific Ocean. In Berry's case, a small oil spill that endangers tidal waters could immediately involve significant clean-up, regulatory investigation and penalties, any or all of which could subject the Company to a significant financial burden. In addition to purchasing insurance to cover certain environmental risks, the Company mitigates this exposure by the development and implementation of emergency response and major oil spill prevention and contingency plans. The Company is also a contract associate member of Clean Seas, an organization with significant experience and resources to contain and minimize the effects of an oil spill.

The Company experienced an oil spill due to a ruptured pipe on its West Montalvo field in December 1993 which required cleanup of the area directly around the pipe, an agricultural runoff pond and the nearby beach and ocean. Although 100% of the Montalvo field's wells and facilities are onshore, part of the spilled crude oil was pumped into the ocean from the agricultural runoff pond. The Company has initiated procedures and made operational improvements to reduce the likelihood of a similar event. A regulatory investigation is proceeding and the Company is potentially subject to fines and penalties (see Item 3. "Legal Proceedings" and Note 12 to the Company's financial statements).

The Company is not aware of any unrecorded environmental claims existing at December 31, 1995 which would have a material impact on the Company's financial condition or results of operations.

Competition

The oil and gas industry is highly competitive. As an independent producer, the Company does not own any refining or retail outlets. It has little control over the price it receives for its crude oil, and 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 since integrated companies, independent companies and individual producers and operators are active bidders for desirable oil and gas properties. Although many of these competitors have greater financial and other resources than the Company, Management believes that it is in a position to compete effectively due to its low cost structure and strong balance sheet.

Employees

The Company had 86 employees at December 31, 1995.

Oil and Gas Properties

The Company spent a total of $.5 million on property acquisitions, $14.0 million on development programs (including $5.2 million on the purchase of the remaining 55% interest in the cogeneration facility) and $1.4 million on exploration programs in 1995. The Company's 1996 budget for capital expenditures on development and exploration activities is $9.4 million of which 99% is earmarked for development. As these activities are influenced by numerous factors, many of which are outside the Company's control, the actual expenditure level may vary considerably from budgeted levels.

In 1995, the Company sold its Rincon properties which comprised 1,631 acres and 15 producing wells, representing approximately 3% of its net daily production and 2% of its reserves.

The principal oil and gas producing properties of Berry are located in Kern County and Ventura County, California.

Development

Homebase - Berry owns and operates working interests in thirteen properties containing 905 acres located in the southern portion of the Midway-Sunset field. The Company estimates these properties account for approximately 76% of the Company's proved oil and gas reserves and approximately 78% of its current daily production. The wells produce from an average depth of approximately 1200'. These properties rely on thermally enhanced oil recovery methods, primarily cyclic steaming. Nine of the thirteen properties are owned in fee and are not burdened by royalties. These nine properties accounted for approximately 73% of Berry's average daily production during 1995 and represent 70% of the Company's proved oil and gas reserves. Berry has a 100% working interest in all the Midway-Sunset properties it operates except one, where the Company owns a 96.875% working interest.

During 1995, a total of 41 development wells were drilled. The objective of this work was to maintain productive capacity and develop additional reserves in the Company's single largest asset. In December 1994, the Company purchased the Alpine property and in 1995, 10 development wells were drilled to exploit the undeveloped reserves of this property. On the Ethel D property, two wells were drilled and followup potential was established.

As of January 1, 1995, the Company owned a 45% interest in the cogeneration plant located on the homebase properties. The purchase of the remaining 55% interest was completed in August of 1995 for a total cost of approximately $5.2 million. Total steam cost savings through December 1995 have exceeded $3 million due to favorable natural gas prices, operating efficiences and other factors existing in the latter part of 1995. The facility produces approximately 12,500 bbls/day of steam, all of which is used in the steaming operations of the homebase properties.

Fairfield - Berry owns and operates approximately 1,824 acres in the northern portion of the Midway-Sunset field which account for approximately 13% of the Company's proved oil and gas reserves and approximately 9% of its daily production. These properties rely on thermally enhanced oil recovery methods, primarily cyclic steaming and steam flooding. Berry's interests consist of four fee properties comprising 1,009 acres and seven leases comprising 815 acres. The wells produce from an average depth of approximately 1200'.

During 1995, the Company drilled two wells in the Potter sand and one well in the Mya sand reservoir. In addition, one evaluation well was drilled and abandoned. The Mya sand cyclic steam program was successful with four wells returned to production. An adjacent 480 acres, comprising the BLM Sec 12 lease, was purchased in 1995 primarily for Mya development potential.

Montalvo - Berry owns 100% of the working interest in six leases in Ventura County, California in the West Montalvo field. Two of the six leases are owned by the State of California. The Company estimates current proved reserves from West Montalvo account for approximately 8% of Berry's proved oil and gas reserves. Total production from these leases, containing 8,563 acres, represents approximately 10% of Berry's total current daily oil and gas production. The wells produce from an average depth of approximately 12,500'.

Development, redrill and remedial well activities were postponed in 1994 while the Company assessed and implemented facility improvements. Facility improvements were completed and five wells were reworked and returned to production in 1995.

Exploration/Outside Operated

The Company participated in the drilling of four exploratory wells in 1995 in which it owned between 12.5% and 18.5% working interest in each well. The Company also participated in two workovers on outside operated properties.

Texas - In the Tyler prospect, the Company drilled the M.L. Collins #1 well to 16,500' and encountered gas shows in three Wilcox intervals between 13,000' and total depth. Extensive testing of the three intervals did not yield commercial production and the cost was written off as a dry hole in 1995. The Company is presently attempting to farm out its remaining interest in the prospect. The Company farmed out its interest in the remaining acreage in the Lexi prospect.

Louisiana - The Earl Chauvin #1 well, a 1993 discovery in the East Lake Boudreaux field, began producing water in the first quarter of 1995. A workover was completed during the year that was successful in bringing the well back on production, but at a much lower rate.

Nevada - In 1995, three exploratory wells were drilled and abandoned as dry holes. The Company has one additional prospect well to drill to fulfill its commitment in a six well multicompany exploratory program.

Oil and Gas Reserves

Reserve Reports - The Company engaged DeGolyer and MacNaughton to estimate the proved oil and gas reserves of the Company for the years ended December 31, 1995 and 1994 for all of the Company's properties and for the year ended December 31, 1993 for the Midway-Sunset field and certain properties located in other fields. The reserves for 1993 for the Rincon and Montalvo fields were prepared by Babson and Sheppard. These two firms (the Petroleum Engineers) were also asked to estimate the future net revenues to be derived from such properties. Each of the Petroleum Engineers is an independent oil and gas reserve engineering firm. In preparing their respective reports for December 31, 1995, 1994 or 1993, each Petroleum Engineer reviewed and examined such geological, economic, engineering and other data provided by the Company as considered necessary under the circumstances applicable to each reserve report. Each Petroleum Engineer also examined the reasonableness of certain economic assumptions regarding estimated operating and development costs and recovery rates in light of economic circumstances as of December 31, 1995, 1994 and 1993. For the Company's operated properties, reserve estimates are filed annually with the U.S. Department of Energy. Refer to the Supplemental information about oil and 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:

	1995	1994	1993
Net Annual Production(1):			
Oil (Mbbls)	3,277	3,250	3,617
Gas (Mmcf)	611	793	771
Average Sales Price:			
Oil (per bbl)	$13.56	$11.61	$11.43
Gas (per mcf)	1.50	1.87	1.96
Average Production Cost (per BOE)(2)	5.41	6.28	6.35

(1) Net production represents production owned by Berry and produced to its interest, less royalty and other similar interests. All oil and gas produced, other than lease fuel needs, is sold at the well site. Berry does not refine any of its production.

(2) Equivalent oil and gas information is at a ratio of 6,000 cubic feet of natural gas to one barrel (bbl) of oil.

Acreage and Wells

At December 31, 1995, the Company's properties accounted for the following developed and undeveloped acres:

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
California	6,175	6,051	6,846	6,846
Nevada	-	-	55,920	9,247
Texas	840	277	9,120	2,889
Other	1,130	204	1,173	293
	8,145	6,532	73,059	19,275

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

Berry currently has 1,551 gross oil wells (1,537 net) and 22 gross gas wells (7 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:

	1995		1994		1993	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells Drilled:						
Productive	0	0.0	0	0.0	3	0.7
Dry (1)	4	0.7	4	0.8	3	0.5
Development Wells Drilled:						
Productive	44	44.0	14	14.0	18	18.0
Dry (1)	1	1.0	0	0.0	0	0.0
Total Wells Drilled:						
Productive	44	44.0	14	14.0	21	18.7
Dry (1)	5	1.7	4	0.8	3	0.5

(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.

As of March 4, 1996, no exploratory wells were being drilled.

Title and Insurance

The Company is not aware of any defect in the title to any of its principal properties. Notwithstanding the absence of a recent title opinion or title insurance policy, the Company believes it has satisfactory title to these 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. To address the hazards inherent in the oil and gas business, the Company maintains a comprehensive insurance program.

Item 3. Legal Proceedings

On December 25, 1993, a crude oil spill was discovered on the Company's West Montalvo field in Ventura County, California. The Company estimates that the total discharge was approximately 2,100 barrels. The Company is aware that certain governmental authorities are currently investigating the circumstances surrounding the spill. The Company paid $.6 million to settle all potential state criminal claims against the Company in August 1994. The Company is working on dealing with all other potential matters related thereto. As of the date of this report, no actions have been filed against the Company in connection with the spill.

The Company was in a dispute with University Cogeneration Partners Ltd., 1985-1, regarding certain costs related to the cogeneration facility operations. The Company was a minority owner in this partnership of which the major asset was the cogeneration facility located on the Company's homebase properties. The Company purchased the remaining interest in the partnership in August 1995 and, in connection therewith, both parties agreed to dismiss all disputed claims.

The information related to certain issues which have been appealed to the U.S. Court of Appeals (Ninth Circuit) is set forth in Note 9 to the Company's financial statements.

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

None.

EXECUTIVE OFFICERS

Listed below are the names, ages (as of December 31, 1995) and positions of the executive officers of Berry and their business experience during at least the past five years.

JERRY V. HOFFMAN, 46, 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. Mr. Hoffman held the Senior Vice President and Chief Financial Officer positions from January 1988 until March 1992. Mr. Hoffman, CPA, has held a variety of other positions with the Company and its prior subsidiaries or successors since February 1985.

DONALD A. DALE, 49, Controller since December 1985. Mr. Dale, CPA, was the Controller for Berry Holding Company from September 1985 to December 1985.

RALPH J. GOEHRING, 39, Chief Financial Officer since March 1992 and Manager of Taxation from September 1987 until March 1992. Mr. Goehring, CPA, is also the Assistant Secretary for Berry Petroleum Company.

CHESTER L. LOVE, 61, Vice President of Engineering since March 1994 and Manager of Engineering from May 1992 to March 1994. Mr. Love, a registered petroleum engineer, was previously a Vice President of Consulting for Scientific Software-Intercomp from 1979 to 1992.

KENNETH A. OLSON, 40, Corporate Secretary since December 1985 and Treasurer since August 1988. Mr. Olson, CPA, has held a variety of other positions with the Company and its prior subsidiaries or successors since July 1985.

MICHAEL R. STARZER, 34, Manager of Corporate Development since April 1995. Mr. Starzer, a registered petroleum engineer, was with Unocal from August 1983 to May 1991 and from August 1993 to April 1995. Mr. Starzer was an engineering consultant and worked with the California State Lands Commission from May 1991 to August 1993.

STEVEN J. THOMAS, 45, Manager of Production since March 1993, joined the Company's engineering department in September 1992. Mr. Thomas, a registered petroleum engineer, was an engineering and petroleum consultant from 1990 to 1992 and was employed by Chevron USA from 1979 to 1990 in various drilling, production and facilities engineering positions.

PART II

Item 5. Market for the Registrant's Common Equity and Related Stockholder 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 1989, the Company adopted a Stockholder Rights Agreement and declared a dividend distribution of one such Right for each outstanding share of Capital Stock on December 22, 1989. Each share of Capital Stock issued after December 22, 1989 includes one Right. The Rights expire on December 8, 1999. See Note 7 of Notes to the Financial Statements.

The Company'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 1995 and 1994 are shown below:

	Low	High	Cash Dividends
1995			
First Quarter	$ 8 3/4	$ 10	$ .10
Second Quarter	9	10 7/8	.10
Third Quarter	9 3/8	10 5/8	.10
Fourth Quarter	9 7/8	10 7/8	.10
1994			
First Quarter	$ 8	$ 9 7/8	$ .10
Second Quarter	8	10 3/4	.10
Third Quarter	8 7/8	10 1/4	.10
Fourth Quarter	9	11 3/8	.10

The number of holders of record of the Company's Common Stock and Class B Stock as of March 4, 1996 was approximately 1,048 and 1, respectively.

The Board of Directors' policy is to declare and pay dividends quarterly in March, June, September and December. The dividend level may change as it is subject to Board approval, and such approval is influenced by the price of crude oil, capital commitments and satisfactory financial results.

Dividends declared on 4,366,400 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 refrence 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, 1995 was derived from the audited financial statements and the accompanying notes to those financial statements (in thousands except per share and per barrel data):

	1995	1994	1993	1992	1991
Statement of Operations Data:					
Operating revenues:					
Sales of oil and gas	$ 45,773	$ 39,451	$ 42,843	$ 49,598	$ 43,439
Blending, net	12	87	265	(1,262)	(1,156)
Operating costs (excluding DD&A and exploratory dry hole costs)	18,264	21,224	23,790	20,931	20,575
General and administrative expenses (excluding DD&A)	4,578	5,118	5,999	5,511	3,840
Depletion, depreciation & amortization (DD&A)	6,847	7,270	9,983	8,123	5,373
Net income (loss)	12,203	(1,129)	32	10,115	16,597
Net income (loss) per share (1)	.56	(.05)	-	.46	.77
Cash dividends per share	.40	.40	.55	.60	.60
Weighted average number of shares outstanding	21,932	21,932	21,926	21,915	21,539
Balance Sheet Data:					
Working capital	$ 36,506	$ 38,273	$ 40,418	$ 50,642	$ 54,420
Shareholders' equity	92,060	88,632	98,323	109,690	113,204
Total assets	117,722	118,254	135,159	140,140	145,594
Operating Data:					
Cash flow from operations	17,070	14,579	10,957	22,169	18,521
Capital expenditures	15,072	6,934	13,983	12,180	14,028
Average sales price per barrel of oil	13.56	11.61	11.43	12.83	12.44
Average production cost per BOE	5.41	6.28	6.35	5.43	6.03
Production:					
Oil (Bbls)	3,277	3,250	3,617	3,683	3,336
Gas (Mcf)	611	793	771	1,029	466
Total (BOE)	3,379	3,382	3,746	3,855	3,414
Proved reserves:					
Oil (Bbls)	77,071	75,996	72,078	72,434	71,054
Gas (Mcf)	5,983	6,530	5,476	10,003	11,772
Total (BOE)	78,068	77,084	72,991	74,101	73,016

(1) Less than $.01 per share in 1993.

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 the three years ended December 31, 1995 and the financial condition, liquidity and capital resources as of December 31, 1995. 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 and gas sold, the type and volume of oil and gas produced and the results of acquisition, development and exploration activities. The average realized prices of oil and gas will fluctuate from one period to another due to world market conditions and other factors. The California crude oil prices are especially sensitive since a significant portion of California's crude oil needs are met by imports from Alaska. The aggregate amount of oil and gas produced may fluctuate based on development and exploitation of oil and gas reserves pursuant to current reservoir management plans. Production rates, steam costs, labor and maintenance expenses 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 returned to profitability in 1995, earning net income of $12.2 million, up significantly from a net loss of $1.1 million in 1994 and net income of $32,000 in 1993. This significant improvement was due primarily to higher oil prices, lower steam costs due to the acquisition of the remaining interest in the cogeneration facility, a 1995 gain on the sale of the Rincon properties, the reduction of exploratory dry hole costs in 1995, and the impairment of properties and oil spill costs recorded in 1994 and 1993 with no comparable charge in 1995.

	1995	1994	1993
Production - BOE Per Day	9,258	9,266	10,261
Average Sales Price - Per BOE	$13.48	$11.60	$11.43
Operating Cost - Per BOE	5.41	6.28	6.35
DD&A - Per BOE	1.88	1.96	2.47

Operating income from producing operations was $21.2 million in 1995, up 83% and 114% from $11.6 million and $9.9 million in 1994 and 1993, respectively. This improvement was due primarily to higher oil prices and reduced operating costs.

The average sales price received per BOE during 1995 of $13.48 was 16% and 18% higher than the prices received in 1994 and 1993, respectively. Oil and gas production in 1995 was comparable to 1994, but down 10% from 1993. On November 1, 1995, the Company sold its Rincon properties which accounted for approximately 283 BOE/day of production. In addition, the Company shut in a number of marginal wells in 1994 and reduced steaming operations from 1993 levels on certain marginally economic properties.

To protect the Company's revenues from potential price declines, effective August 1, 1995, the Company entered into a bracketed zero cost collar hedge contract with a California refiner for a term of 18 months related to approximately 22% of its crude oil production. The posted price of the Company's 13 degree API gravity crude oil was used as the basis for the hedge. There is no initial cost to the Company and there will be no material financial impact unless crude oil prices increase or decrease significantly from current levels. A similar contract for an additional 11% of the Company's crude production with a 12 month term was entered into in early 1996.

Operating costs per BOE in 1995 declined 14% from 1994 to $5.41 due largely to a reduction in steam costs which have historically represented the largest component of operating costs to the Company. As part of the Company's continuing effort to reduce operating costs, the Company purchased the remaining 55% interest in the cogeneration plant which provides steam to the Company's homebase properties located in the Midway-Sunset field. In addition, the Company increased production from the Montalvo field during 1995 and sold its Rincon properties on November 1, 1995, both of which incurred higher operating costs relative to the other properties operated by the Company. Due to these events and the Company's ongoing cost reduction program, operating costs per BOE continued to decline to $4.63 in the fourth quarter of 1995 from $5.19 and $5.80 in the third and second quarters of 1995, respectively.

DD&A per BOE declined to $1.88 in 1995 from $1.96 and $2.47 in 1994 and 1993, respectively. This decline was due primarily to the lower depletable basis of the Company's assets resulting from the impairment, dry hole and abandonment charges recorded in 1994.

On November 1, 1995, the Company sold its Rincon properties located in Ventura County, California for approximately $5.8 million plus certain reimbursements, which resulted in a pre-tax gain of approximately $3.1 million. Net daily production from the six leases represented approximately 3% of the Company's 1995 production levels. This property was considered non-core, was expensive to operate and would have required significant capital outlays to maximize the property's value.

General

Interest income in 1995 was $2 million, up from $1.6 million and $1.9 million in 1994 and 1993, respectively, due primarily to higher average interest rates on invested cash balances in 1995.

General and administrative expenses were $4.6 million in 1995, down 10% and 23% from $5.1 million and $6 million incurred in 1994 and 1993, respectively. The Company is focused on cost reduction and incurred lower payroll related costs due to attrition, the consolidation of certain administrative functions and lower medical costs.

The Company's effective income tax rate in 1995 was 37%. The pre-tax losses incurred in 1994 and 1993 resulted in effective tax benefits of 42% and 102%, respectively. The most important factor affecting 1994 and 1993 was the impact of certain tax benefits, primarily enhanced oil recovery credits and percentage depletion, as applied to the pre-tax losses in those years.

In the fourth quarter of 1995, the Company adopted Financial Accounting Standard (SFAS) No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of". This adoption resulted in no charges to the Company's financial statements for 1995, and is not significantly different than the Company's impairment policy in effect prior to the adoption.

Financial Condition, Liquidity and Capital Resources

Working capital at December 31, 1995 was $36.5 million, down from $38.3 million and $40.4 million at December 31, 1994 and 1993, respectively. Cash flow provided by operating activities of $17.1 million was up 17% and 55% from $14.6 million and $11.0 million in 1994 and 1993, respectively. Cash flow was higher in 1995 due to higher oil prices and lower operating costs due primarily to the purchase of the cogeneration facility in 1995. The Company sold its Rincon properties in 1995 for an additional $5.8 million in cash plus certain reimbursements. However, working capital declined 5% due to capital expenditures of $15.1 million incurred during the year, which included approximately $5.2 million on the purchase of the remaining 55% interest in the Company's cogeneration facility, $4.8 million on the further development of the homebase properties, including the drilling of 45 additional development wells, and $1.9 million on the further development of the Montalvo field, including the conversion of two wells to a long-stroke rod pump system and the return to production of four wells on the PRC 735 lease. In 1995, the Company paid $8.8 million in dividends to its shareholders. In addition, $2.9 million was paid in federal and state income taxes resulting from an adverse judgment by the U.S. Tax Court against the Company (see Note 9 to the Company's financial statements).

The Company had a $1 million Revolving Credit and Term Loan Agreement with a major California bank until early 1996. There were no outstanding borrowings under this line. The Company is working on obtaining a new Revolving Credit/Term Loan Facility which, when completed, may be used for future acquisitions or other corporate purposes.

The total proved reserves at December 31, 1995 were 78.1 million BOE, up from 77.1 million BOE at December 31, 1994 and 73.0 million BOE at December 31, 1993. Although the Company produced 3.4 million BOE during the year and sold its Rincon properties, the Company saw an increase in reserves due primarily to the further development of the Company's PRC 735 lease, the development of the Alpine lease purchased in the fourth quarter of 1994, the acquisition of the USL 12 lease in the Midway-Sunset field, higher oil prices and lower estimated future operating costs. The 1995 development program (excluding the purchase of the remaining interest in the cogeneration facility) and USL 12 lease acquisition were successful in adding proved reserves, replacing 182% of production at an average cost of $1.71 per BOE. The Company's estimated future pre-tax discounted cash flow, using a 10% discount rate, increased 17% and 516% to $308.4 million at December 31, 1995 from $263.9 million at December 31, 1994 and $50.1 million at December 31, 1993, respectively.

Future Developments

In 1996, the Company plans to adopt the disclosure option of SFAS No. 123, "Accounting for Stock-Based Compensation".

Senate Bill S.395 allowing the export of ANS crude oil has been passed by Congress and signed by the President, and is currently undergoing limited public hearings. Because of this legislation, the Company expects that a larger portion of this crude oil will be sold in markets other than California beginning in the second quarter of 1996. The long term impact may be to reduce the differential between crude oil prices on the West Coast and other parts of the country.

The Company currently sells the electricity produced by its cogeneration facility to a large California-based utility under a contract (Standard Offer 2) which determines the electricity payment based upon electrical capacity and by energy provided. This contract will expire on January 15, 1997. Under current law, the Company has the right to enter into a similar contract (Standard Offer 1) upon expiration with the same utility at the same energy payment but a lower capacity payment. The Company is analyzing its options with respect to future electricity sales. Management believes that the deregulation in the electrical utility industry (currently targeted for 1998 in California) may provide opportunities for the Company to maximize the benefits of its cogeneration facility. However, failure to achieve a similar or better contract than the existing contract will likely result in higher operating costs related to steam generation than exist currently.

A portion of the natural gas purchases made by the Company for use primarily in its steaming operations is subject to an existing long-term transportion agreement with a California utility. The resulting transportation charges related to the gas obtained are significantly above current prevailing market rates. The agreement will expire in April 1997 and the Company expects to realize a reduction in operating costs related to this event in 1997 and beyond.

On February 10, 1996, the President signed into law a bill which authorizes the sale, within two years, of the Elk Hills Naval Petroleum Reserve located in Kern County, California. The Company believes the sale may result in a significant concentration of the ownership of the light crude oil used as blending stock for the heavy crude oil produced in the San Joaquin Valley. If such concentration were to occur, it is possible that the lack of light oil availability could have an adverse impact on the marketability and prices received for this heavy crude oil.

Impact of Inflation

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

Item 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 Board of Directors
Berry Petroleum Company

We have audited the accompanying balance sheets of Berry Petroleum Company as of December 31, 1995 and 1994, and the related statements of operations, shareholders' equity and cash flows for each of the three years in the period ended December 31, 1995. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Berry Petroleum Company as of December 31, 1995 and 1994, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1995, in conformity with generally accepted accounting principles.

COOPERS & LYBRAND L.L.P.

/s/ Coopers & Lybrand L.L.P.

February 21, 1996
Los Angeles, California

BERRY PETROLEUM COMPANY
Balance Sheets
December 31, 1995 and 1994
(In Thousands Except Share Information)

	1995	1994
ASSETS		
Current assets:		
Cash and cash equivalents	$ 18,759	$ 7,466
Short-term investments available for sale	15,695	27,617
Accounts receivable	8,414	9,471
Deferred income taxes	1,175	3,315
Prepaid expenses and other	1,157	1,073
Total current assets	45,200	48,942
Oil and gas properties (successful efforts basis), buildings and equipment, net	72,042	66,915
Other assets	480	2,397
	$ 117,722	$ 118,254
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 3,086	$ 5,913
Accrued liabilities	3,912	4,637
Federal and state income taxes payable	1,696	119
Total current liabilities	8,694	10,669
Deferred income taxes	16,968	18,953
Contingencies (Note 12)		
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; 21,033,055 shares issued and outstanding	210	210
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	52,850	52,852
Retained earnings	38,991	35,561
Total shareholders' equity	92,060	88,632
	$ 117,722	$ 118,254

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

BERRY PETROLEUM COMPANY
Statements of Operations
Years ended December 31, 1995, 1994 and 1993
(In Thousands Except Per Share Data)

	1995	1994	1993
Revenues:			
Sales of oil and gas	$ 45,773	$ 39,451	$ 42,843
Interest	2,040	1,616	1,893
Gain (loss) on sale of assets	3,073	113	(1,100)
Other income, net	304	155	460
	51,190	41,335	44,096
Expenses:			
Operating costs	18,264	21,224	23,790
Depreciation, depletion & amortization	6,847	7,270	9,983
Impairment of properties	-	2,915	2,911
Oil spill costs	-	1,344	2,004
Exploratory dry hole costs	2,012	5,414	788
General and administrative	4,578	5,118	5,999
	31,701	43,285	45,475
Income (loss) before income taxes	19,489	(1,950)	(1,379)
Provision (benefit) for income taxes	7,286	(821)	(1,411)
Net income (loss)	$ 12,203	$ (1,129)	$ 32
Net income (loss) per share	$ .56	$ (.05)	$ -
Weighted average number of shares of capital stock used to calculate earnings per share	21,932	21,932	21,926

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

BERRY PETROLEUM COMPANY
Statements of Shareholders' Equity
Years Ended December 31, 1995, 1994 and 1993
(In Thousands Except Per Share Data)

	Capital Stock Class A	Class B	Capital in Excess of Par Value	Retained Earnings	Shareholders' Equity
Balances at January 1, 1993	$ 210	$ 9	$ 51,977	$ 57,494	$ 109,690
Stock options exercised	-	-	664	-	664
Cash dividends declared - $.55 per share	-	-	-	(12,063)	(12,063)
Net income	-	-	-	32	32
Balances at December 31, 1993	210	9	52,641	45,463	98,323
Stock options expired	-	-	211	-	211
Cash dividends declared - $.40 per share	-	-	-	(8,773)	(8,773)
Net loss	-	-	-	(1,129)	(1,129)
Balances at December 31, 1994	210	9	52,852	35,561	88,632
Stock retired	-	-	(2)	-	(2)
Cash dividends declared - $.40 per share	-	-	-	(8,773)	(8,773)
Net income	-	-	-	12,203	12,203
Balances at December 31, 1995	$ 210	$ 9	$ 52,850	$ 38,991	$ 92,060

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

BERRY PETROLEUM COMPANY
Statements of Cash Flows
Years Ended December 31, 1995, 1994 and 1993
(In Thousands)

Cash flows from operating activities:	1995	1994	1993

Net income (loss)	$ 12,203	$ (1,129)	$ 32
Depletion, depreciation and amortization	6,847	7,270	9,983
(Gain) loss on sale of assets	(3,073)	(113)	1,100
Exploratory dryhole costs	1,990	5,090	170
Impairment of properties	-	2,915	2,911
Increase (decrease) in deferred income tax liability	(1,985)	(762)	1,536
Other, net	(50)	504	(377)
Net working capital provided by operating activities	15,932	13,775	15,355
Decrease (increase) in current assets other than cash, cash equivalents and short-term investments	3,113	7,256	(9,248)
Increase (decrease) in current liabilities	(1,975)	(6,452)	4,850
Net cash provided by operating activities	17,070	14,579	10,957
Cash flows from investing activities:			
Capital expenditures	(15,072)	(6,934)	(13,983)
Proceeds from sale of assets	6,242	327	413
Purchase of short-term investments	(3,078)	(30,524)	(15,560)
Maturities of short-term investments	15,000	29,874	30,290
Other, net	(96)	(540)	(610)
Net cash provided by (used in) investing activities	2,996	(7,797)	550
Cash flows from financing activities:			
Dividends paid	(8,773)	(8,773)	(12,063)
Proceeds from exercise of stock options	-	-	664
Net cash used in financing activities	(8,773)	(8,773)	(11,399)
Net increase (decrease) in cash and cash equivalents	11,293	(1,991)	108
Cash and cash equivalents at beginning of year	7,466	9,457	9,349
Cash and cash equivalents at end of year	$ 18,759	$ 7,466	$ 9,457
Supplemental disclosures of cash flow information:			
Interest paid	$ 12	$ 5	$ 8
Income taxes paid	$ 5,554	$ 484	$ 765

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

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

1. General

The Company is an independent energy company engaged in the acquisition, exploration, exploitation, development, production, and marketing of crude oil and natural gas. All of the Company's oil and gas reserves are located in the United States, with 89% of the reserves located in the Midway-Sunset field in the San Joaquin Valley in California. Approximately 97% of the Company's production is crude oil, which is principally sold to other oil companies for processing in refineries located in California.

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

2. Summary of significant accounting policies

Cash and cash equivalents

Cash equivalents consist principally of commercial paper and money market funds. The Company considers all highly liquid investments purchased with a remaining maturity of three months or less to be cash equivalents. Cash equivalents of $13.4 million and $6.0 million at December 31, 1995 and 1994, respectively, are stated at cost, which approximates market.

Short-term investments

All short-term investments are classified as available for sale. Short-term investments consist principally of United States treasury notes, corporate notes, state and local municipal bonds and auction market preferred stock 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. For the three years ended December 31, 1995, realized and unrealized gains and losses were insignificant to the financial statements. United States treasury notes with an aggregate market value of $.6 million are pledged as collateral to the California State Lands Commission as a performance bond on the Company's Montalvo properties.

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 mineral interests in oil and gas properties, to drill and complete development wells and drill and complete exploratory wells that find proved reserves are capitalized. Exploratory dryhole 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. 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 depletion, depreciation and amortization 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. When assets are sold, the applicable costs and accumulated depreciation 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)

In the fourth quarter of 1995, the Company adopted Statement of Financial Account Standards (SFAS) No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." This change had no effect on the Company's financial statements. Pursuant to this standard, assets are grouped at the lowest level for which there are identifiable cash flows. If it is determined that the book value of long-lived assets cannot be recovered by estimated future undiscounted cash flows, they will be written down to fair value.

Steam Costs

The costs of producing steam by the cogeneration plant are recorded as an operating expense of the Company. Proceeds received from the sale of electricity produced by the plant are reported as a reduction to operating costs in the Company's financial statements.

Income Taxes

Income taxes are provided based on the liability method of accounting pursuant to SFAS No. 109, "Accounting for Income Taxes". The provision for income taxes is based on pretax financial accounting income. Deferred tax assets and liabilities are recognized for the future expected tax consequences of temporary differences between income tax and financial reporting and principally relate to differences in the tax bases of assets and liabilities and their reported amounts, using enacted tax rates in effect for the year in which differences are expected to reverse. If it is more likely than not that some portion or all of a deferred tax asset will not be realized, a valuation allowance is recognized.

Earnings per share

Earnings per share is computed by dividing net income by the weighted average number of capital shares and dilutive common stock equivalents, if any, outstanding during the year.

Reclassifications

Certain reclassifications have been made to the 1994 and 1993 financial statements to conform with the 1995 presentation.

3. Fair value of financial instruments

Financial instruments consist of cash and short-term investments, whose carrying amounts are not materially different from their fair values because of the short maturity of those instruments. The Company's short-term investments available for sale at December 31, 1995 consist primarily of United States treasury notes (71%) and corporate notes (29%). All of the short-term investments at December 31, 1995 mature in one year or less.

To protect the Company's revenues from potential price declines, effective August 1, 1995, the Company entered into a bracketed zero cost collar hedge contract with a California refiner for a term of 18 months related to approximately 22% of its crude oil production. The posted price of the Company's 13 degree API gravity crude oil was used as the basis for the hedge. There is no initial cost to the Company and there will be no material financial impact unless crude oil prices increase or decrease significantly from current levels. A similar contract for an additional 11% of the Company's crude oil production with a 12 month term was entered into in early 1996.

4. Concentration of Credit Risks

The Company sells oil, gas and natural gas liquids to pipelines and refineries. Credit is extended based on an evaluation of the customer's financial condition. For the three years ended December 31, 1995, the Company has experienced no credit losses on the sale of oil, gas and natural gas liquids.

The Company places its temporary cash investments with high credit quality financial institutions and limits the amount of credit exposure to any one financial institution. For the three years ended December 31, 1995, the Company has not incurred losses related to these investments.

The following summarizes the accounts receivable balances at December 31, 1995 and sales activity with significant customers for each of the years ended December 31, 1995, 1994 and 1993 (in thousands):

Customer	Accounts Receivable December 31, 1995	Sales For the Year Ended December 31, 1995	1994	1993
A	$ 1,372	$ 12,641	$ 16,027	$ 16,747
B	961	12,918	11,319	11,686
C	724	9,214	-	-
D	-	5,265	-	-
	$ 3,057	$ 40,038	$ 27,346	$ 28,433

The loss of any of these customers could have a temporarily adverse impact on the Company's revenues.

5. Oil and gas properties, buildings and equipment

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

	1995	1994
Oil and gas:		
Proved properties:		
Producing properties, including intangible drilling costs	$ 55,202	$ 56,216
Lease and well equipment	75,470	67,232
Unproved properties	162	383
	130,834	123,831
Less accumulated depletion, depreciation and amortization	61,456	59,909
	69,378	63,922
Commercial and other:		
Land	151	151
Buildings and improvements	3,734	3,806
Machinery and equipment	4,026	3,969
	7,911	7,926
Less accumulation depreciation	5,247	4,933
	2,664	2,993
	$ 72,042	$ 66,915

5. Oil and gas properties, buildings and equipment (cont'd)

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

	1995	1994	1993
Acquisition of properties	$ 503	$ 1,023	$ -
Exploration	1,420	1,701	3,336
Development	14,034	4,678	10,958
	$ 15,957	$ 7,402	$ 14,294

Results of operations from oil and gas producing and exploration activities

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

	1995	1994	1993
Sales to unaffiliated parties	$ 45,773	$ 39,451	$ 42,843
Production costs	(18,264)	(21,224)	(23,790)
Exploration expenses	(2,012)	(5,414)	(788)
Depletion, depreciation and amortization	(6,354)	(6,627)	(9,143)
	19,143	6,186	9,122
Income tax expenses	(6,433)	(1,723)	(2,225)
Results of operations from producing and exploration activities	$ 12,710	$ 4,463	$ 6,897

In 1994, the Company recorded an impairment writedown of $2.9 million related to its Poso Creek and Kern Front properties and a producing well at Rincon. Similarly, in 1993 the Company recorded an impairment writedown of

$2.9 million related to certain properties in East Texas which were subsequently assigned to another company in December 1994.

6. Debt obligations

The Company had a $1 million Revolving Credit and Term Loan Agreement (Agreement) with a major California bank which was terminated in early 1996. At December 31, 1995, the Company had no outstanding borrowings or letters of credit under 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.

In December 1989, the Company adopted a Stockholder Rights Agreement and declared a dividend distribution of one Right for each outstanding share of Capital Stock. Each Right, when exercisable, entitles the holder to purchase one one-hundredth of a share of a Series A 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 in December 1999 or may be redeemed by the Company at 1 cent 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. 250,000 shares of the Company's Preferred Stock have been designated Series A Junior Participating Preferred Stock and reserved for issuance upon exercise of the Rights.

The Company issued no shares in 1995 or 1994 through its stock option plans. During 1993, 44,536 shares were issued through these plans.

Dividends declared on 4,366,400 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. Transactions with affiliates

The University Cogeneration Partners, Ltd. 1985-1, a limited partnership, was formed in 1985 to finance the construction of a cogeneration plant on the Company's properties. The Company also committed to purchase the steam generated by the plant and supply the natural gas to fuel the plant. At December 31, 1994 the receivable due from the Cogeneration Partnership for natural gas purchases, net of the steam sales to the Company, was $.8 million. The Company owned approximately 45% of the partnership and its investment of $1.9 million was accounted for at cost. On August 1, 1995, the Company purchased the remaining 55% interest in the cogeneration plant for approximately $5.2 million. The total cost of the cogeneration plant is included in lease and well equipment at December 31, 1995. Amounts paid by the Company for the steam in 1995 (through July), 1994 and 1993 were $2.6 million, $4.6 million and $4.3 million, respectively.

9. Income taxes

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

	1995	1994	1993
Current:			
Federal	$ 5,089	$ 158	$ (873)
State	2,042	(56)	(74)
	7,131	102	(947)
Deferred:			
Federal	828	(1,077)	(369)
State	(673)	154	(95)
	155	(923)	(464)
	$ 7,286	$ (821)	$(1,411)

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 are as follows (in thousands):

	Dec. 31, 1995	Dec. 31, 1994
Deferred tax asset		
Federal benefit of state taxes	$ 1,756	$ 1,334
Differences between financial reporting and tax bases of assets acquired	-	3,226
Net operating loss carryforwards	171	1,470
Credit/deduction carryforwards	634	3,037
Other, net	368	712
Valuation allowance	-	(3,089)
	2,929	6,690
Deferred tax liability	(15,195)	(16,567)
Depreciation and depletion	(3,122)	(3,795)
State taxes, net	(405)	(1,966)
Other, net	(18,722)	(22,328)
Net deferred tax liability	$(15,793)	$(15,638)

9. Income taxes (cont'd)

Income taxes computed by applying U.S. statutory federal rates to income (loss) before income taxes are reconciled to the provision (benefit) for income taxes as follows (in thousands):

	1995	1994	1993
Tax (benefit) computed at statutory federal rate	$ 6,821	$ (663)	$ (469)
Increase (decrease) in taxes resulting from:			
Asset acquisition/sale differences	1,315	394	637
Nontaxable income	(28)	(171)	(323)
Percentage depletion	(402)	(290)	(286)
State taxes, net	888	98	(113)
Enhanced oil recovery, nonconventional fuel tax and alternative minimum tax credits	(1,115)	(406)	(1199)
Other, net	(193)	217	342
	$ 7,286	$ (821)	$ (1,411)
Effective tax rate	37.4%	(42.1)%	(102.3)%

The Company has $.5 million of loss carryforwards which may be utilized in future years to reduce the Company's federal income taxes. These loss carryforwards expire in the year 2000. The Company also has approximately $.6 million of various tax credit carryforwards available to reduce future federal income taxes. If not fully utilized, certain enhanced oil recovery tax credits of $.5 million will expire in the year 2009. The other credits may be carried forward indefinitely.

The Company went to trial in April 1993 before the U.S. Tax Court on certain unresolved federal tax issues relating to the years 1987 through 1989. The Court's decision was rendered in May of 1995, resulting in an approximate $.5 million charge in the second quarter of 1995 and the payment of approximately $2.9 million in federal and state taxes. Due to this decision, the Company no longer has benefit of certain loss carryforwards and asset bases. Therefore, these deferred tax assets, as well as the valuation allowance provided against these assets, have been removed. All federal and state taxes and accrued interest owed with respect to these issues have been paid. The Company is pursuing an appeal of the Court's decision with respect to certain issues to the U.S. Court of Appeals (Ninth Circuit).

10. Stock option and stock appreciation rights plans

The Company has a 1987 Nonstatutory Stock Option Plan (the NSO Plan) and a 1987 Stock Appreciation Rights Plan (the SAR Plan). The NSO Plan provided for the granting of options (Options) to purchase up to an aggregate of 700,000 shares of Common Stock. The SAR Plan originally authorized a maximum of 700,000 shares of Common Stock subject to stock appreciation rights (SARs). Holders of SARs have the right upon exercise to receive a payment, payable at the discretion of the Compensation Committee in cash or in shares of Common Stock, equal to the amount by which the market price exceeds the Base Price (as defined) with respect to the shares subject to such SARs on the date of exercise. In December 1994, the Board of Directors adopted a resolution to terminate the 1987 Stock Appreciation Rights Plan without utilizing the 307,860 SARs which were still available for issuance. The 39,740 currently outstanding SARs are still available for exercise under the original terms of issuance.

On December 2, 1994, the Board of Directors of the Company adopted the Berry Petroleum Company 1994 Stock Option Plan (the 1994 Plan). The 1994 Plan was approved by the shareholders in May 1995 and provides for the granting of stock options to purchase up to an aggregate of 1,000,000 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 2, 1994, 300,000 Options were issued to certain key employees at an exercise price of $10.75 per share, which was the closing market price of the Company's Class A Common Stock on the New York Stock Exchange on that date. The Options vest 25% per year for four years. The Options granted on December 2, 1994 utilized all 193,800 remaining Options from the 1987 Nonstatutory Stock Option Plan and 106,200 shares from the 1994 Plan. 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 Options. 33,000 Options were issued on December 2, 1994 and 1995, (3,000 Options to each of the eleven non-employee directors each year) at an exercise price of $10.75 and $10.625 per share, respectively. The Options granted to the non-employee directors vest immediately. The formula plan provides for the annual grant of 3,000 Options to each non-employee director holding office on each December 2nd at the fair market value on the date of grant.

Included in general and administrative expenses is $9,000 in 1995, $0 in 1994 and $(18,000) in 1993 for compensation expense related to the Options and SARs granted to date. The credit in 1993 was due to the decline in the Company's stock price during that year. Because the options issued on December 2, 1994 and 1995 were all issued at current market value, there was no accounting charge to the Company in connection with the Option grants. The accrued liabilities for the NSO and SAR Plans are $.2 million at December 31, 1995 and 1994.

In 1996, the Company plans to adopt the disclosure option of SFAS No. 123, "Accounting for Stock-Based Compensation".

10. Stock option and stock appreciation rights plans (cont'd)

	1995		1994	
	Options	SARs	Options	SARs
Balance outstanding, January 1	398,141	39,740	142,941	69,020
Granted	33,000	-	333,000	-
Exercised	-	-	-	(5,380)
Canceled/expired	-	-	(77,800)	(23,900)
Balance outstanding, December 31	431,141	39,740	398,141	39,740
Balance exercisable at December 31	223,941	39,740	65,141	39,740
Available for future grant	827,800	-	860,800	-
Exercise Price	$ 9.80 to 10.75	$ 9.80 to 10.00	$ 9.80 to 10.75	$ 9.80 to 10.00
Market price at date of exercise	$ -	$ -	$ -	$ 10.50 to 10.875

During 1993, 270,961 Options and 142,980 SARs were exercised at an exercise price ranging from $9.80 to $10.00 and a market price ranging from $11.63 to $13.13.

11. 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 their 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 results are achieved. Due to improved financial results, the monthly matching contributions ranged from 6% to 9% during 1995. For 1994 and 1993, all matching contributions were at the 6% rate. The Company's contributions to the 401(k) Plan were $.2 million in 1995, $.2 million in 1994 and $.3 million in 1993. Total contributions in 1995 were lower than in 1993 due to a decline in the number of employees at the Company.

12. Oil Spill

On December 25, 1993, the Company experienced a crude oil spill on its PRC 735 State lease located in the West Montalvo field in Ventura County, California. The spill required clean-up of the area directly around the pipe as well as the nearby ocean and an agricultural runoff pond. Working closely with the United States Coast Guard, the California Department of Fish and Game, and other regulatory agencies, the Company substantially completed the clean-up of the spill in January 1994. The Company negotiated a resolution of the state criminal investigation for a total of $.6 million in August 1994. Governmental investigations continue regarding potential civil and federal criminal penalties, if any.

Management believes the Company has an adequate amount of insurance coverage for the majority of the costs associated with the spill and has received preliminary coverage letters from its insurance carriers tendering coverage, subject to certain reservations. Definitive determination will not become known until some time in the future. The Company estimates the total cost of the spill, net of insurance reimbursement, to be a minimum of $3.3 million and a maximum of $5.1 million. Since no other amount in the range is more likely to occur, the minimum amount was expensed by the Company ($1.3 million in the second quarter of 1994 and $2 million in 1993). The costs incurred and estimated to be incurred in connection with the

12. Oil Spill (cont'd)

spill not yet paid by the Company are included in accrued liabilities at December 31, 1995, and the probable remaining minimum insurance reimbursement is included in accounts receivable. As of December 31, 1995, the Company had received approximately $8.1 million under its insurance coverage as reimbursement for costs incurred and paid by the Company associated with the spill.

13. Quarterly financial data (unaudited)

The following is a tabulation of unaudited quarterly operating results for 1995 and 1994 (in thousands).

1995	Operating Revenues (A)	Gross Profit (A)	Net Income (Loss)	Net Income (Loss) Per Share
First Quarter	$ 10,445	$ 3,872	$ 2,210	$ .10
Second Quarter	12,436	5,933	2,876	.13
Third Quarter	12,172	5,688	3,374	.16
Fourth Quarter	10,732	3,394	3,743	.17
	$ 45,785	$ 18,887	$ 12,203	$ .56
1994				
First Quarter	$ 7,205	$ (18)	$ (598)	$ (.03)
Second Quarter	9,827	(5,916)(B)	(4,665)(B)	(.21)
Third Quarter	11,640	4,602	2,609	.12
Fourth Quarter	10,866	3,141	1,525	.07
	$ 39,538	$ 1,809	$ (1,129)	$ (.05)

(A) Includes sales of oil and gas and blending, net.

(B) Includes property impairment of $2.9 million and additional oil spill costs accrual of $1.3 million.

BERRY PETROLEUM COMPANY

Supplemental Information About Oil & Gas Producing Activities (Unaudited)

The following estimates of proved oil and gas reserves, both developed and undeveloped, represent interests owned by the Company located solely within the United States. Proved reserves represent estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells for which relatively major expenditures are required for completion.

Disclosures of oil and gas reserves which follow are based on estimates prepared primarily by independent engineering consultants for the three years ended December 31, 1995. 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.

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, 1995, 1994 and 1993, and changes in such quantities during each of the years then ended were as follows (in thousands):

	1995		1994		1993	
	Oil Mbbls	Gas Mmcf	Oil Mbbls	Gas Mmcf	Oil Mbbls	Gas Mmcf
Proved developed and undeveloped reserves:						
Beginning of year	75,996	6,530	72,078	5,476	72,434	10,003
Revision of previous estimates	5,266	803	6,002	1,847	3,203	(5,735)
Production	(3,277)	(611)	(3,250)	(793)	(3,617)	(771)
Discoveries	-	-	-	-	58	1,979
Sale of reserves in place	(1,698)	(739)	-	-	-	-
Purchase of reserves in place	784	-	1,166	-	-	-
End of year	77,071	5,983	75,996	6,530	72,078	5,476
Proved developed reserves:						
Beginning of year	62,718	4,727	62,261	4,810	65,516	6,797
End of year	62,856	3,380	62,718	4,727	62,261	4,810

BERRY PETROLEUM COMPANY

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

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

The standardized measure has been prepared assuming year-end sales prices adjusted for fixed and determinable contractual price changes, year-end costs and statutory income tax rates previously legislated, 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.

	1995	1994	1993
Future cash inflows	$1,039,150	$ 960,412	$ 607,137
Future production and development costs	311,955	317,735	473,903
Future income tax expenses	245,416	213,225	37,332
Future net cash flows	481,779	429,452	95,902
10% annual discount for estimated timing of cash flows	273,478	248,499	59,276
Standardized measure of discounted future net cash flows	$ 208,301	$ 180,953	$ 36,626
Pre-tax standardized measure of discounted future net cash flows	$ 308,370	$ 263,890	$ 50,124

Average sales prices at December 31:

	1995	1994	1993
Oil ($/Bbl)	$ 13.39	$ 12.49	$ 8.25
Gas ($/Mcf)	1.45	1.78	2.18

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

	1995	1994	1993
Standardized measure - beginning of year	$ 180,953	$ 36,626	$ 101,054
Sales of oil and gas produced, net of production costs	(27,509)	(18,227)	(18,697)
Revisions to estimates of proved reserves:			
Net changes in sales prices and production costs	41,726	194,099	(110,914)
Revisions of previous quantity estimates	23,584	24,315	2,261
Change in estimated future development costs	(14,234)	(5,470)	6,751
Extensions, discoveries and improved recovery			

less related costs	-	-	2,929
Purchases of reserves in place	2,316	3,815	-
Sale of reserves in place	(8,645)	-	-
Development costs incurred during the period	14,034	4,678	10,958
Accretion of discount	2,639	4,602	15,555
Income taxes	(13,126)	(68,416)	36,920
Other	6,563	4,931	(10,191)
Net increase (decrease)	27,348	144,327	(64,428)
Standardized measure - end of year	$ 208,301	$ 180,953	$ 36,626

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 caption "Voting Securities" and "Principal Shareholders and Ownership by Management" 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.

Section 16(a) of the Securities Exchange Act of 1934 requires the Company's executive officers and directors and persons beneficially owning greater than ten percent of the outstanding Shares to file reports of ownership and changes in ownership with the Securities and Exchange Commission. 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, except that one report for one transaction was filed late by Mr. Chester L. Love.

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.

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 A Junior Participating Preferred Stock (filed as Exhibit 3.3 to the Annual Report on Form 10-K for the year ended December 31, 1989, File No. 0-11708)	
4.1*	Rights Agreement between Registrant and Bank of America dated as of December 8, 1989 (filed as Exhibit 1 to Form 8-K filed on December 20, 1989, File No. 0-11708)	
10.1*	Description of Cash Bonus Plan of Berry Petroleum Company (filed as Exhibit 10.7 to the Annual Report on Form 10-K for the year ended December 31, 1990, File No. 1-9735)	
10.2*	Salary Continuation Agreement dated as of March 20, 1987, as amended August 28, 1987, by and between Registrant and Jerry V. Hoffman (filed as Exhibit 10.11 to the Registration Statement on Form S-1 filed on June 7, 1989, File No. 33-29165)	
10.3*	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)	
10.4*	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)	
10.5*	1987 Nonstatutory Stock Option Plan and 1987 Stock Appreciation Rights Plan as amended March 18, 1988 (filed as Exhibit 10.14 in Registrant's Registration Statement on Form S-8 filed on July 28, 1988, File No. 33-23326)	
10.6*	Service Contract by and between Registrant and Pride Petroleum Services, Inc. dated November 1, 1989 (filed as Exhibit 10.23 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1989, File No. 0-11708)	

C. Exhibits (cont'd)

Exhibit No.	Description of Exhibit	Page
10.7*	1994 Stock Option Plan (filed as Exhibit 10.8 in Registrant's Annual Report on Form 10-K for the year ended December 31, 1994, File No. 1-9735)	
10.8	Standard Offer #2 Power Purchase Agreement dated May 1984, as amended by and between Registrant and Pacific Gas and Electric Company	38
23.1	Consent of Coopers & Lybrand L.L.P.	119
23.2	Consent of Babson and Sheppard	120
23.3	Consent of DeGolyer and MacNaughton	121
27. **	Financial Data Schedule	122
99.1	Undertaking for Form S-8 Registration Statements	123
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

** Included in the Company's electronic filing on EDGAR

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 15, 1996.

BERRY PETROLEUM COMPANY

/s/ JERRY V. HOFFMAN	/s/ RALPH J. GOEHRING	/s/ DONALD A. DALE
JERRY V. HOFFMAN	RALPH J. GOEHRING	DONALD A. DALE
President and Chief Executive Officer	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/ Harvey L. Bryant Harvey L. Bryant	Chairman of the Board and Director	March 15, 1996
/s/ Jerry V. Hoffman Jerry V. Hoffman	President, Chief Executive Officer and Director	March 15, 1996
/s/ Benton Bejach Benton Bejach	Director	March 15, 1996
/s/ William F. Berry William F. Berry	Director	March 15, 1996
/s/ Gerry A. Biller Gerry A. Biller	Director	March 15, 1996
/s/ Ralph B. Busch, Jr. Ralph B. Busch, Jr.	Director	March 15, 1996
/s/ William E. Bush, Jr.	Director	March 15, 1996

William E. Bush, Jr.

/s/ William B. Charles William B. Charles	Director	March 15, 1996
/s/ Richard F. Downs Richard F. Downs	Director	March 15, 1996
/s/ John A. Hagg John A. Hagg	Director	March 15, 1996
/s/ Thomas J. Jamieson Thomas J. Jamieson	Director	March 15, 1996
/s/ Roger G. Martin Roger G. Martin	Director	March 15, 1996

PACIFIC GAS AND ELECTRIC COMPANY

STANDARD OFFER #2

POWER PURCHASE AGREEMENT

FOR

FIRM CAPACITY AND ENERGY

MAY 1984

STANDARD OFFER #2:

FIRM CAPACITY AND ENERGY

POWER PURCHASE AGREEMENT

CONTENTS

S.O. #2
May 7, 1984

FIRM CAPACITY AND ENERGY

POWER PURCHASE AGREEMENT

BETWEEN

UNIVERSITY COGENERATION INC., 1985-1

AND

PACIFIC GAS AND ELECTRIC COMPANY

UNIVERSITY COGENERATION INC., 1985-1 (Seller), and PACIFIC GAS AND ELECTRIC COMPANY (PGandE), referred to collectively as Parties and individually as Party, agree as follows:

ARTICLE 1 QUALIFYING STATUS

Seller warrants that, at the date of first power deliveries from Seller's Facility ((1)) and during the term of agreement, its Facility shall meet the qualifying facility requirements established as of the effective date of this Agreement by the Federal Energy Regulatory Commission's rules (18 Code of Federal Regulations 292) implementing the Public Utility Regulatory Policies Act of 1978 (16 U.S.C.A. 796, et seq.).

((1)) Underlining identifies those terms which are defined in Section A-1 of Appendix A.

ARTICLE 2 PURCHASE OF POWER

(a) Seller shall sell and deliver and PGandE shall purchase and accept delivery of firm capacity and energy at the voltage level of______((1)) kV as indicated below --

1. Contract capacity - 34,000 kW; and
2. Energy - net energy output ((2)).

Seller may convert its energy sale option as provided in Section A-3 of Appendix A.

(b) Seller shall provide the firm capacity and energy set forth above from its 38,000 kW (ISO) Facility located at Section 28, township 12 north, range 24 west, 3 1/2 miles south of Taft, Kern County, California.

(c) The scheduled operation date of the Facility is November 1986. At the end of each calendar quarter Seller shall give written notice to PGandE of any change in the scheduled operation date.

((1)) The Seller requests, and PGandE consents, that this blank not be filled in at the time of executing the Agreement, because the Seller, recognizing that the information is not yet available to make a definitive determination of the number to be inserted in this blank, shall request PGandE to perform an interconnection study to be done in its accustomed manner of making such studies to determine the number to be inserted.

((2)) Insert either net energy output or surplus energy output to show the energy sale option selected by Seller.

(d) To avoid exceeding the physical limitations of the interconnection facilities, Seller shall limit the Facility's actual rate of delivery into the PGandE system to ________ ((1)) kW.

(e) The primary energy source for the Facility is natural gas.

(f) If Seller does not begin construction of its Facility by June 1986, PGandE may reallocate the existing capacity on PGandE's transmission and/or distribution system which would have been used to accommodate Seller's power deliveries to other uses. In the event of such reallocation, Seller shall pay PGandE for the cost of any upgrades or additions to PGandE's system necessary to accommodate the output from the Facility. Such additional facilities shall be installed, owned, and maintained in accordance with the applicable PGandE tariff.

(g) The transformer loss adjustment factor is __________((1))((2)).

((1)) The Seller requests, and PGandE consents, that this blank not be filled in at the time of executing the Agreement, because the Seller, recognizing that the information is not yet available to make a definitive determination of the number to be inserted in this blank, shall request PGandE to perform an interconnection study to be done in its accustomed manner of making such studies to determine the number to be inserted.

((2)) If Seller chooses to have meters placed on Seller's side of the transformer, an estimated transformer loss adjustment factor of 2 percent, unless the Parties agree otherwise, will be applied. This estimated transformer loss figure will be adjusted to a measurement of actual transformer losses performed at Seller's request and expense.

ARTICLE 3 PURCHASE PRICE

(a) PGandE shall pay Seller for firm capacity at the contract capacity price under Option 1 set forth in Section C-5 of Appendix C. The contract capacity price is derived from PGandE's full avoided costs as approved by the CPUC. PGandE's obligation to pay for the contract capacity shall begin on the actual operation date. Seller elects to have its contract capacity price determined from the firm capacity price schedule in effect on the date of execution of this Agreement((1)). The contract capacity price shall be subject to adjustment as provided for in Appendix D.

(b) PGandE shall pay Seller for energy at prices equal to PGandE's full short run avoided operating costs as approved by the CPUC.

(c) The contract capacity price is applicable to deliveries of capacity beginning after December 30, 1982.

ARTICLE 4 NOTICES

All written notices shall be directed as follows:

To PGandE: Pacific Gas and Electric Company
Attention: Vice President-
Electric Operations
77 Beale Street
San Francisco, CA 94106

((1)) Insert either the date of execution of this Agreement or the actual operation date.

To Seller: University Cogeneration Inc.
University Energy
Attention: Secretary
3430 Camino Del Rio North
Suite 200
San Diego, CA 92108

ARTICLE 5 DESIGNATED SWITCHING CENTER

The designated PGandE switching center shall be unless changed by PGandE:

PGandE Midway Substation
Buttonwillow, CA
(805) 764-5229

ARTICLE 6 TERMS AND CONDITIONS

This Agreement includes the following appendices which are attached and incorporated by reference:

Appendix A - GENERAL TERMS AND CONDITIONS
Appendix B - ENERGY PRICES
Appendix C - FIRM CAPACITY PRICE SCHEDULE
Appendix D - ADJUSTMENT OF CAPACITY PAYMENTS IN THE EVENT OF TERMINATION OR REDUCTION
Appendix E - INTERCONNECTION

ARTICLE 7 TERM OF AGREEMENT

This Agreement shall be binding upon execution and remain in effect thereafter for 10 years from the actual operation date; provided, however, that it shall terminate if the actual operation date does not occur within five years of the execution date.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized representatives and effective as of the last date set forth below.

UNIVERSITY COGENERATION INC., 1985-1	PACIFIC GAS AND ELECTRIC COMPANY
BY: /s/ John R. Zanot JOHN R. ZANOT	By: /s/ Nolan Davies NOLAN DAVIES
TITLE: Secretary	TITLE: Vice President - Planning and Research
DATE SIGNED: April 16, 1985	DATE SIGNED: April 23, 1985

APPENDIX A

GENERAL TERMS AND CONDITIONS

CONTENTS

Section

Page

S.O. #2
May 7, 1984

APPENDIX A

GENERAL TERMS AND CONDITIONS

A-1 DEFINITIONS

Whenever used in this Agreement, appendices, and attachments hereto, the following terms shall have the following meanings:

Actual operation date - The day following the day during which all features and equipment of the Facility are demonstrated to PGandE's satisfaction to be capable of operating simultaneously to deliver power continuously into PGandE's system as provided in this Agreement.

Adjusted capacity price - The $/kW-year purchase price from Table B, Appendix C for the period of Seller's actual performance.

Capacity sale reduction - A reduction in the amount of capacity provided or to be provided under this Agreement, other than a temporary reduction during probationary periods under Section C-5.

Contract capacity - That capacity identified in Article 2(a) except as otherwise changed as provided herein.

Contract capacity price - The capacity price applicable for the period from the actual operation date through the term of agreement from either the firm capacity price schedule, Table B of Appendix C, or the successor to Table B in effect on the Actual operation date. Seller has indicated its choice of firm capacity price schedule in Article 3(a).

Contract termination - The early termination of this Agreement.

CPUC - The Public Utilities Commission of the State of California.

Current firm capacity price - The $/kW-year capacity price from the firm capacity price schedule published by PGandE at the time notice of termination or reduction of contract capacity is given, for a term equal to the period from the date of termination or reduction to the end of the term of agreement.

Designated PGandE switching center - That switching center or other PGandE installation identified in Article 5.

Dispatchable - The Facility is operable and can be called upon at any time to increase its deliveries of capacity to any level up to the contract capacity.

Facility - That generation apparatus described in Article 2 and all associated equipment owned, maintained, and operated by Seller.

Firm capacity price schedule - The periodically published schedule of the $/kW-year prices that PGandE offers to pay for capacity. See Table B, Appendix C.

Forced outage - Any outage resulting from a design defect, inadequate construction, operator error or a breakdown of the mechanical or electrical equipment that fully or partially curtails the electrical output of the Facility.

Interconnection facilities - All means required and apparatus installed to interconnect and deliver power from the Facility to the PGandE system including, but not limited to, connection, transformation, switching, metering, communications, and safety equipment, such as equipment required to protect (1) the PGandE system and its customers from faults occurring at the Facility, and (2) the Facility from faults occurring on the PGandE system or on the systems of others to which the PGandE system is directly or indirectly connected. Interconnection facilities also include any necessary additions and reinforcements by PGandE to the PGandE system required as a result of the interconnection of the Facility to the PGandE system.

Net energy output - The Facility's gross output in kilowatt-hours less station use and transformation and transmission losses to the point of delivery into the PGandE system. Where PGandE agrees that it is impractical to connect the station use on the generator side of the power purchase meter, PGandE may, at its option, apply a station load adjustment.

Prudent electrical practices - Those practices, methods, and equipment, as changed from time to time, that are commonly used in prudent electrical engineering and operations to design and operate electric equipment lawfully and with safety, dependability, efficiency, and economy.

Scheduled operation date - The day specified in Article 2(c) when the Facility is, by Seller's estimate, expected to produce energy and capacity that will be available for delivery to PGandE.

Special facilities - Those additions and reinforcements to the PGandE system which are needed to accommodate the maximum delivery of energy and capacity from the facility as provided in this Agreement and those parts of the interconnection facilities which are owned and maintained by PGandE at Seller's request, including metering and data processing equipment.

All special facilities shall be owned, operated, and maintained pursuant to PGandE's electric Rule No. 21, which is attached hereto.

Station use - Energy used to operate the Facility's auxiliary equipment. The auxiliary equipment includes, but is not limited to, forced and induced draft fans, cooling towers, boiler feed pumps, lubricating oil systems, plant lighting, fuel handling systems, control systems, and sump pumps.

Surplus energy output - The Facility's gross output, in kilowatt-hours, less station use, and any other use by Seller, and transformation and transmission losses to the point of delivery into the PGandE system.

Term of agreement - The period of time during which this Agreement will be in effect as provided in Article 7.

Voltage level - The voltage at which the Facility interconnects with the PGandE system, measured at the point of delivery.

A-2 CONSTRUCTION

A-2.1 Land Rights

PGandE's equipment is to be installed on property owned by other than Seller. Seller shall, at its own cost and expense, obtain from the owners thereof all necessary rights of way and easements, in a form satisfactory to PGandE, for the construction, operation, maintenance, and replacement of PGandE's equipment upon such property. If Seller is unable to obtain such rights of way and easements, Seller shall reimburse PGandE for all costs, including attorney's fees and litigation expenses, incurred by PGandE in obtaining them. PGandE shall at all times have the right of ingress to and egress from the Facility at all reasonable hours for any purposes reasonably connected with this Agreement or the exercise of any and all rights secured to PGandE by law or its tariff schedules.

A-2.2 Design, Construction, Ownership, and Maintenance

(a) Seller shall design, construct, install, own, operate, and maintain all interconnection facilities, except special facilities, to the point of interconnection with the PGandE system as required for PGandE to receive firm capacity and energy from the Facility. The Facility and interconnection facilities shall meet all requirements of applicable codes and all standards of prudent electrical practices and shall be maintained in a safe and prudent manner. A description of the interconnection facilities for which Seller is solely responsible is set forth in Appendix E, or if the interconnection requirements have not yet been determined at the time of the execution of this Agreement, the description of such facilities will be

appended to this Agreement at the time such determination is made.

(b) Seller shall submit to PGandE the design and all specifications for the interconnection facilities (except special facilities) and, at PGandE's option, the Facility, for review and written acceptance prior to their release for construction purposes. PGandE shall notify Seller in writing of the outcome of PGandE's review of the design and specifications for Seller's interconnection facilities (and the Facility, if requested) within 30 days of the receipt of the design and all of the specifications for the interconnection facilities (and the Facility, if requested). Any flaws perceived by PGandE in the design and specifications for the interconnection facilities (and the Facility, if requested) will be described in PGandE's written notification. PGandE's review and acceptance of the design and specifications shall not be construed as confirming or endorsing the design and specifications or as warranting their safety, durability, or reliability. PGandE shall not, by reason of such review or lack of review, be responsible for strength, details of design, adequacy, or capacity of equipment built pursuant to such design and specifications, nor shall PGandE's acceptance be deemed to be an endorsement of any of such equipment. Seller shall change the interconnection facilities as may be reasonably required by PGandE to meet changing requirements of the PGandE system.

(c) In the event it is necessary for PGandE to install interconnection facilities for the purposes of this Agreement, they shall be installed as special facilities.

(d) Upon the request of Seller, PGandE shall provide a binding estimate for the installation of interconnection facilities by PGandE.

A-2.3 Meter Installation

(a) PGandE shall specify, provide, install, own, operate, and maintain as special facilities all metering and data processing equipment for the registration and recording of energy and other related parameters which are required for the reporting of data to PGandE and for computing the payment due Seller from PGandE.

(b) Seller shall provide, construct, install, own, and maintain at Seller's expense all that is required to accommodate the metering and data processing equipment, such as, but not limited to, metal-clad switchgear, switchboards, cubicles, metering panels, enclosures, conduits, rack structures, and equipment mounting pads.

(c) PGandE shall permit meters to be fixed on PGandE's side of the transformer. If meters are placed on PGandE's side of the transformer, service will be provided at the available primary voltage and no transformer loss adjustment will be made. If Seller chooses to have meters placed on

Seller's side of the transformer, an estimated transformer loss adjustment factor of 2 percent, unless the Parties agree otherwise, will be applied.

A-3 ENERGY SALE OPTIONS

A-3.1 General

Seller has two energy sale options, net energy output or surplus energy output. Seller has made its initial selection in Article 2(a).

A-3.2 Energy Sale Conversion

(a) Seller is entitled to convert from one option to the other 12 months after execution of this Agreement, and thereafter at least 12 months after the effective date of the most recent conversion, subject to the following conditions:

(1) Seller shall provide PGandE with a written request to convert its energy sale option.

(2) Seller shall comply with all applicable tariffs on file with the CPUC and contracts in effect between the Parties at the time of conversion covering the existing and proposed (i) facilities used to serve Seller's

premises and (ii) interconnection facilities.

(3) Seller shall install and operate equipment required by PGandE to prevent PGandE from serving any part of Seller's load which is served by the Facility and not under contract for PGandE standby service. At Seller's request PGandE shall provide this equipment as special facilities.

(4) If the energy sale conversion results in a capacity sale reduction, the provisions in Appendix D shall apply.

(b) If, as a result of an energy sales conversion, Seller no longer requires the use of interconnection facilities installed and/or operated and maintained by PGandE as special facilities under a Special Facilities Agreement, Seller may reserve these facilities, for its future use, by continuing its performance under its Special Facilities Agreement. If Seller does not wish to reserve such facilities, it may terminate its Special Facilities Agreement.

If Seller's energy sale conversion results in its discontinuation of its use of PGandE facilities not covered by Seller's Special Facilities Agreement, Seller cannot reserve those facilities for future use. Seller's future use of such facilities shall be contingent upon the availability of such facilities at the time Seller requests such use. If such facilities are not available, Seller shall bear the expense necessary to install, own, and maintain the needed additional facilities in accordance with PGandE's applicable tariff.

(c) PGandE shall process requests for conversion in the order received. The effective date of conversion shall depend on the completion of the changes required to accommodate Seller's energy sale conversion.

A-4 OPERATION

A-4.2 Inspection and Approval

Seller shall not operate the Facility in parallel with PGandE's system until an authorized PGandE representative has inspected the interconnection facilities, and PGandE has given written approval to begin parallel operation. Seller shall notify PGandE of the Facility's start-up date at least 45 days prior to such date. PGandE shall inspect the interconnecting facilities within 30 days of the receipt of such notice. If parallel operation is not authorized by PGandE, PGandE shall notify Seller in writing within five days after inspection of the reason authorization for parallel operation was withheld.

A-4.2 Facility Operation and Maintenance

Seller shall operate and maintain its Facility according to prudent electrical practices, applicable laws, orders, rules, and tariffs and shall provide such reactive power support as may be reasonably required by PGandE to maintain system voltage level and power factor. Seller shall operate the Facility at the power factors or voltage levels prescribed by PGandE's system dispatcher or designated representative. If Seller fails to provide reactive power support, PGandE may do so at Seller's expense.

A-4.3 Point of Delivery

Seller shall deliver the energy at the point where Seller's electrical conductors (or those of Seller's agent) contact PGandE's system as it shall exist whenever the deliveries are being made or at such other point or points as the Parties may agree in writing. The initial point of delivery of Seller's power to the PGandE system is set forth in Appendix E.

A-4.4 Operating Communications

(a) Seller shall maintain operating communications with the designated PGandE switching center. The operating communications shall include, but not be limited to, system paralleling or separation, schedule and unscheduled shutdowns, equipment clearances, levels of operating voltage or power factor and daily capacity and generation reports.

(b) Seller shall keep a daily operations log for each generating unit which shall include information on unit availability, maintenance outages, circuit breaker trip operations requiring a manual reset, and any significant events related to the operation of the Facility.

(c) If Seller makes deliveries greater than one megawatt, Seller shall measure and register on a graphic recording device power in kW and voltage in kV at a location within the Facility agreed to by both parties.

(d) If Seller makes deliveries greater than one and up to and including ten megawatts, Seller shall report to the designated PGandE switching center, twice a day at agreed upon times for the current day's operation, the hourly readings in kW of capacity delivered and the energy in kWh delivered since the last report.

(e) If Seller makes deliveries of greater than ten megawatts, Seller shall telemeter the delivered capacity and energy information, including real power in kW, reactive power in kVAR, and energy in kWh to a switching center selected by PGandE. PGandE may also required Seller to telemeter transmission

kW, kVAR, and kV data depending on the number of generators and transmission configuration. Seller shall provide and maintain the data circuits required for telemetering. When telemetering is inoperative, Seller shall report daily the capacity delivered each hour and the energy delivered each day to the designated PGandE switching center.

(f) If Seller provides dispatchable capacity greater than ten megawatts pursuant to Option 1 in Section C-5 of Appendix C, Seller may be required by PGandE to provide telemetering and control equipment to allow the Facility to respond to system load frequency requirements on digital control from PGandE.

A-4.5 Meter Testing and Inspection

(a) All meters used to provide data for the computation of the payments due Seller from PGandE shall be sealed, and the seals shall be broken only by PGandE when the meters are to be inspected, tested, or adjusted.

(b) PGandE shall inspect and test all meters upon their installation and annually thereafter. At Seller's request and expense, PGandE shall inspect or test a meter more frequently. PGandE shall give reasonable notice to Seller of the time when any inspection or test shall take place, and Seller may have representatives present at the test or inspection. If a meter is found to be inaccurate or defective, PGandE shall adjust, repair, or replace it at its expense in order to provide accurate metering.

A-4.6 Adjustments to Meter Measurements

If a meter fails to register, or if the measurement made by a meter during a test varies by more than two percent from the measurement made by the standard meter used in the test, an adjustment shall be made correcting all measurements made by the inaccurate meter for -- (1) the actual period during which inaccurate measurements were made, if the period can be determined, or if not, (2) the period immediately preceding the test of the meter equal to one-half the time from the date of the last previous test of the meter, provided that the period covered by the correction shall not exceed six months.

A-5 PAYMENT

PGandE shall mail to Seller not later than 30 days after the end of each monthly billing period, (1) a statement showing the capacity and energy delivered to PGandE during on-peak, partial-peak, and off-peak periods during the monthly billing period, (2) PGandE's computation of the amount due Seller, and (3) PGandE's check in payment of said amount. Except as provided in Section A-6, if within 30 days of receipt of this statement Seller does not make a report in writing to PGandE of an error, Seller shall be deemed to have

waived any error in PGandE's statement, computation, and payment, and they shall be considered correct and complete.

A-6 ADJUSTMENTS OF PAYMENTS

(a) In the event adjustments to payments are required as a result of inaccurate meters, PGandE shall use the corrected measurements described in Section A-4.6 to recompute the amount due from PGandE to Seller for the firm capacity and energy delivered under this Agreement during the period of inaccuracy.

(b) The additional payment to Seller or refund to PGandE shall be made within 30 days of notification of the owing Party of the amount due.

A-7 ACCESS TO RECORDS AND PGandE DATA

Each Party, after giving reasonable written notice to the other Party, shall have the right of access to all metering and related records including operations logs of the Facility. Data filed by PGandE with the CPUC pursuant to CPUC orders governing the purchase of power from qualifying facilities shall be provided to Seller upon request; provided that Seller shall reimburse PGandE for the costs it incurs to respond to such request.

A-8 CURTAILMENT OF DELIVERIES AND HYDRO SPILL CONDITIONS

(a) PGandE shall not be obligated to accept or pay for and may require Seller to interrupt or reduce deliveries of energy (1) when necessary in order to construct, install, maintain, repair, replace, remove, investigate, or inspect any of its equipment or any part of its system, or (2) if it determines that interruption or reduction is necessary because of emergencies, forced outages, force majeure, or compliance with prudent electrical practices. PGandE shall make reasonable efforts to coordinate any interruptions or reduced deliveries for reasons specified in (1) above to periods of scheduled outages for which Seller has provided proper notice.

(b) In anticipation of a period of hydro spill conditions, as defined by the CPUC, PGandE may notify Seller that any purchases of energy from Seller during such period shall be at hydro savings prices quoted by PGandE. If Seller delivers energy to PGandE during any such period, Seller shall be paid hydro savings prices for those deliveries in lieu of prices which would otherwise be applicable. The hydro savings prices shall be calculated by PGandE using the following formula:

AQF - S x PP
AQF

where:

AQF = Energy, in kWh, projected to be available during hydro spill conditions from all qualifying facilities under agreements containing hydro savings price provisions.

S = Potential energy, in kWh, from PGandE hydro facilities which will be spilled if all AQF is delivered to PGandE.

PP = Prices published by PGandE for purchases during other than hydro spill conditions.

(c) PGandE shall not be obligated to accept or pay for and may require Seller with a Facility with a nameplate rating of one megawatt or greater to interrupt or reduce deliveries of energy during periods when purchases under this Agreement would result in costs greater than those which PGandE would incur if it did not make such purchases but instead generated an equivalent amount of energy itself.

(d) Whenever possible, PGandE shall give Seller reasonable notice of the possibility that interruption or reduction of deliveries under subsections (a) or (c), above, may be required. PGandE shall give Seller notice of general periods when hydro spill conditions are anticipated, and shall give Seller as much advance notice as practical of any specific hydro spill period and the hydro savings price which will be applicable during such period. Before interrupting or reducing deliveries under subsection (c), above, and

before invoking hydro savings prices under subsection (b), above, PGandE shall take reasonable steps to make economy sales of the surplus energy giving rise to the condition. If such economy sales are made, while the surplus energy conditions exists Seller shall be paid at the economy sales price obtained by PGandE in lieu of the otherwise applicable prices.

(e) If Seller is selling net energy output to PGandE and simultaneously purchasing its electrical needs from PGandE, energy curtailed pursuant to subsections (b) or (c) above shall not be used by Seller to meet its electrical needs. When Seller elects not to sell energy to PGandE at the hydro savings price pursuant to subsection (b) or when PGandE curtails deliveries of energy pursuant to subsection (c), Seller shall continue to purchase all its electrical needs from PGandE. If Seller is selling surplus energy output to PGandE, subsections (b) or (c) shall only apply to the surplus energy output being delivered to PGandE, and Seller can continue to internally use that generation it has retained for its own use.

(f) PGandE and Seller desire to and will continue to explore alternatives to Subsections (b), (c), (d), and (e) above that would compensate Seller for granting to PGandE increased flexibility to interrupt or reduce energy deliveries. The parties agree to amend this Section A-8 accordingly if they reach agreement on such an alternative.

A-9 FORCE MAJEURE

(a) The term force majeure as used herein means unforeseeable causes, other than forced outages, beyond the reasonable control of and without the fault or negligence of the Party claiming force majeure including, but not limited to, acts of God, labor disputes, sudden actions of the elements, actions by federal, state, and municipal agencies, and actions of legislative, judicial, or regulatory agencies which conflict with the terms of this Agreement.

(b) If either Party because of force majeure is rendered wholly or partly unable to perform its obligations under this Agreement, that Party shall be excused from whatever performance is affected by the force majeure to the extent so affected provided that:

(1) the non-performing Party, within two weeks after the occurrence of the force majeure, gives the other Party written notice describing the particulars of the occurrence,

(2) the suspension of performance is of no greater scope and of no longer duration than is required by the force majeure,

(3) the non-performing Party uses its best efforts to remedy its inability to perform (this subsection shall not require the settlement of any strike, walkout, lockout or other labor dispute on terms which,

in the sole judgment of the Party involved in the dispute, are contrary to its interest. It is understood and agreed that the settlement of strikes, walkouts, lockouts or other labor disputes shall be at the sole discretion of the Party having the difficulty),

(4) when the non-performing Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party written notice to that effect, and

(5) capacity payments during such periods of force majeure on Seller's part shall be governed by Section C-2(c) of Appendix C.

(c) In the event a Party is unable to perform due to legislative, judicial, or regulatory agency action, this Agreement shall be renegotiated to comply with the legal change which caused the non-performance.

A-10 INDEMNITY

Each Party as indemnitor shall save harmless and indemnify the other Party and the directors, officers, and employees of such other Party against and from any and all loss and liability for injuries to persons including employees of either Party, and property damages including property of either Party resulting from or arising out of (1) the engineering, design, construction, maintenance, or operation of, or (2) the making of replacements,

additions, or betterments to, the indemnitor's facilities. This indemnity and save harmless provision shall apply notwithstanding the active or passive negligence of the indemnitee. Neither Party shall be indemnified hereunder for its liability or loss resulting from its sole negligence or willful misconduct. The indemnitor shall, on the other Party's request, defend any suit asserting a claim covered by this indemnity and shall pay all costs, including reasonable attorney fees, that may be incurred by the other Party in enforcing this indemnity.

A-11 LIABILITY; DEDICATION

(a) Nothing in this Agreement shall create any duty to, any standard of care with reference to, or any liability to any person not a Party to it. Neither Party shall be liable to the other Party for consequential damages.

(b) Each Party shall be responsible for protecting its facilities from possible damage by reason of electrical disturbances or faults caused by the operation, faulty operation, or nonoperation of the other Party's facilities, and such other Party shall not be liable for any such damages so caused.

(c) No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any

portion thereof to the other Party or to the public or affect the status of PGandE as an independent public utility corporation or Seller as an independent individual or entity and not a public utility.

A-12 SEVERAL OBLIGATIONS

Except where specifically stated in this Agreement to be otherwise, the duties, obligations, and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership, or joint venture or impose a trust or partnership duty, obligation, or liability on or with regard to either Party. Each Party shall be liable individually and severally for its own obligations under this Agreement.

A-13 NON-WAIVER

Failure to enforce any right or obligation by either Party with respect to any matter arising in connection with this Agreement shall not constitute a waiver as to that matter or any other matter.

A-14 ASSIGNMENT

Neither Party shall voluntarily assign its rights nor delegate its duties under this Agreement, or any part of such rights or duties, without the written consent of the other Party, except in connection with the sale or merger of a substantial portion of its properties. Any such assignment or delegation made without such written consent shall be null and void. Consent for assignment shall not be withheld unreasonably. Such assignment shall include, unless otherwise specified therein, all of Seller's rights to any refunds which might become due under this Agreement.

A-15 CAPTIONS

All indexes, titles, subject headings, section titles, and similar items are provided for the purpose of reference and convenience and are not intended to affect the meaning of the contents or scope of this Agreement.

A-16 CHOICE OF LAWS

This Agreement shall be interpreted in accordance with the laws of the State of California, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

A-17 GOVERNMENTAL JURISDICTION AND AUTHORIZATION

Seller shall obtain any governmental authorizations and permits required for the construction and operation of the Facility. Seller shall reimburse PGandE for any and all losses, damages, claims, penalties, or liability it incurs as a result of Seller's failure to obtain or maintain such authorizations and permits.

A-18 NOTICES

Any notice, demand, or request required or permitted to be given by either Party to the other, and any instrument required or permitted to be tendered or delivered by either Party to the other, shall be in writing (except as provided in Section C-3) and so given, tendered, or delivered, as the case may be, by depositing the same in any United States Post Office with postage prepaid for transmission by certified mail, return receipt requested, addressed to the Party, or personally delivered to the Party, at the address in Article 4 of this Agreement. Changes in such designation may be made by notice similarly given.

A-19 INSURANCE

A-19.1 General Liability Coverage

(a) Seller shall maintain during the performance hereof, General Liability Insurance ((1)) of not less than $1,000,000 if the Facility is over 100 kW, $500,000 if the Facility is over 20 kW to 100 kW, and $100,000 if the Facility is 20 kW or below of combined single limit or equivalent for bodily injury, personal injury, and property damage as the result of any one occurrence.

(b) General Liability Insurance shall include coverage for Premises-Operations, Owners and Contractors Protective, Products/Completed Operations Hazard, Explosion, Collapse, Underground, Contractual Liability, and Broad Form Property Damage including Completed Operations.

(c) Such insurance, by endorsement to the policy(ies), shall include PGandE as an additional insured if the Facility is over 100 kW insofar as work performed by Seller for PGandE is concerned, shall contain a severability of interest clause, shall provide that PGandE shall not by reason of its inclusion as an additional insured incur

((1)) Governmental agencies which have an established record of self-insurance may provide the required coverage through self-insurance.

liability to the insurance carrier for payment of premium for such insurance, and shall provide for 30-days' written notice to PGandE prior to cancellation, termination, alteration, or material change of such insurance.

A-19.2 Additional Insurance Provisions

(a) Evidence of coverage described above in Section A-19.1 shall state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance maintained by PGandE.

(b) PGandE shall have the right to inspect or obtain a copy of the original policy(ies) of insurance.

(c) Seller shall furnish the required certificates ((1)) and endorsements to PGandE prior to commencing operation.

(d) All insurance certificates 1, endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued and submitted to the following:

PACIFIC GAS AND ELECTRIC COMPANY
Attention: Manager - Insurance Department
77 Beale Street, Room E280
San Francisco, CA 94106

((1)) A governmental agency qualifying to maintain self-insurance should provide a statement of self-insurance.

A-20 REASONABLE ACTION BY EACH PARTY

Any action required of either Party pursuant to this agreement, including those in the sole discretion of one Party, shall be undertaken in a reasonable manner and in a manner least likely to cause harm to the other party. This paragraph is not in any way intended to require special treatment of Seller as compared to other QFs.

APPENDIX B
ENERGY PRICES

TABLE A

Energy Prices Effective February 1 - April 30, 1985

The energy purchase price calculations which will apply to energy deliveries determined from meter readings taken during February, March and April 1985 are as follows:

Time Period	(a) Incremental Energy Rate ((1)) (Btu/kWh)	(b) Cost of Energy ((2)) ($/10-6 Btu)	(c) Revenue Requirement for Cash Working Capital ((3)) ($/kWh)	(d) Energy Purchase Price (d)={(a)x(b)}+(c) ((4)) ($/kWh)
February 1- April 30 (Period B)				
Time of Delivery Basis:				
On-Peak	16,320	5.2394	0.00053	0.08604
Partial-Peak	15,689	5.2394	0.00051	0.08271
Off-Peak	11,625	5.2394	0.00038	0.06129
Seasonal Average (Period B)	13,692	5.2394	0.00045	0.07219

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((1)) Incremental energy rates (Btu/kWh) for Seasonal Period A and Seasonal Period B are derived from the marginal energy costs (including variable operating and maintenance expense) adopted by the CPUC in Decision No. 83-12-068 (page 339). They are based upon natural gas as the incremental fuel and weighted average hydroelectric power conditions.

((2)) Cost of natural gas under PGandE Gas Schedule No. G-55 effective February 1, 1985 per Advice No. 1304-G.

((3)) Revenue Requirement for Cash Working Capital as prescribed by the CPUC in Decision No. 83-12-068.

((4)) Energy Purchase Price = (Incremental Energy Rate x Cost of Energy) + Revenue Requirement for Cash Working Capital. The energy purchase price excludes the applicable energy line loss adjustment factors. However, as ordered by Ordering Paragraph No. 12(j) of CPUC Decision No. 82-12-120, this figure is currently 1.0 for transmission and primary distribution loss adjustments and is equal to marginal cost line loss adjustment factors for the secondary distribution voltage level. These factors may be changed by the CPUC in the future. The currently applicable energy loss adjustment factors are shown in Table C.

TABLE B((1))
Time Periods

	Monday through Friday ((2))	Saturdays ((2))	Sundays and Holidays
Seasonal Period A (May 1 through September 30)			
On-Peak	12:30 p.m. to 6:30 p.m.		

Partial-Peak	8:30 a.m. to 12:30 p.m.	8:30 a.m. to 10:30 p.m.	
	6:30 p.m. to 10:30 p.m.		
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day
Seasonal Period B (October 1 through April 30)			
On-Peak	4:30 p.m. to 8:30 p.m.		
Partial-Peak	8:30 p.m. to 10:30 p.m.	8:30 a.m. to 10:30 p.m.	
	8:30 a.m. to 4:30 p.m.		
Off-Peak	10:30 p.m. to 8:30 a.m.	10:30 p.m. to 8:30 a.m.	All Day

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((1)) This table is subject to change to accord with the on-peak, partial-peak, and off-peak periods as defined in PGandE's own rate schedules for the sale of electricity to its large industrial customers.

((2)) Except the following holidays: New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, and Christmas Day, as specified in Public Law 90-363 (5 U.S.C.A. Section 6103(a)).

S.O. #2
May 7, 1984

TABLE C

Energy Loss Adjustment Factors ((1))

	Transmission	Primary Distribution	Secondary Distribution
Seasonal Period A (May 1 through September 30)			
On-Peak	1.0	1.0	1.0148
Partial-Peak	1.0	1.0	1.0131
Off-Peak	1.0	1.0	1.0093
Seasonal Period B (October 1 through April 30)			
On-Peak	1.0	1.0	1.0128
Partial-Peak	1.0	1.0	1.0119
Off-Peak	1.0	1.0	1.0087

((1)) The applicable energy loss adjustment factors may be revised pursuant to orders of the CPUC.

S.O. #2
May 7, 1984

APPENDIX C

FIRM CAPACITY PRICE SCHEDULE

CONTENTS

APPENDIX C

FIRM CAPACITY PRICE SCHEDULE

C-1 GENERAL

This Appendix C establishes conditions and prices under which PGandE shall pay for firm capacity.

C-2 PERFORMANCE REQUIREMENTS

(a) To receive full capacity payments the Facility must meet the following requirements:

(1) The contract capacity shall be available ((1)) for all of the on-peak hours 2 in the peak months on the PGandE system, which are presently the months of June, July and August, subject to a 20 percent allowance for forced outages in any month. Compliance with this provision shall be based on the Facility's total on-peak availability ((1)) for each of the peak months and shall exclude any energy associated with generation levels greater than the contract capacity.

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((1)) For purposes of Option 1, available means either dispatchable by PGandE or actually delivered to PGandE. For purposes of Option 2, available means actually delivered to PGandE.

((2)) On-peak, partial-peak, and off-peak hours are defined in Table B, Appendix B.

(2) If Seller selects Option 1, the contract capacity shall be dispatchable throughout the year, subject to (i) a monthly allowance for forced outages of 20% of the hours Seller is called upon to deliver power to PGandE and (ii) the allowances for scheduled maintenance outages. Except during the peak months on the PGandE system, Seller may accumulate and apply the 20 percent allowance for forced outages for any consecutive three month period. Seller shall demonstrate that the Facility is fueled by a reliable fuel supply and adequate fuel storage is available to deliver power as requested by PGandE's system dispatcher. Such demonstration could reasonably include documentation of the current availability of the fuel, identification of the source, and production of contracts for its purchase and supply.

(b) If Seller is prevented from meeting the performance requirements because of a forced outage on the PGandE system or a condition set forth in Section A-8, PGandE shall continue capacity payments. Under Option 2, capacity payments will be calculated in the same manner used for scheduled maintenance outages.

(c) If Seller is prevents from meeting the performance requirements because of force majeure, PGandE shall continue capacity payments for ninety days from the occurrence of the force majeure. Thereafter, Seller shall be

deemed to have failed to have met the performance requirements. Under Option 2, capacity payments will be calculated in the same manner used for scheduled maintenance outages.

(d) If Seller is prevented from meeting the performance requirements because of extreme dry year conditions, PGandE shall continue capacity payments. Extreme dry year conditions are drier than those used to establish contract capacity pursuant to Section C-8. Seller shall warrant to PGandE that the Facility is a hydroelectric facility and that such conditions are the sole cause of Seller's inability to meet its contract capacity obligations. Under Option 1, starting with the month in which Seller cannot provide its contract capacity, payments shall be made under Option 2 for a one-year period, and if at the end of this one-year period Seller is not able to resume the contract capacity due solely to continued extreme dry year conditions, Seller shall continue to receive payments under Option 2 for additional one-year periods as long as such conditions continue to exist.

(e) If Seller is prevents from meeting the performance requirements for reasons other than those described above in Sections C-2(b), (c) or (d):

(1) Seller shall receive the reduced capacity payments as provided in Section C-5 for a probationary period not to exceed 15 months, or as otherwise agreed to by the Parties.

(2) If, at the end of the probationary period Seller has not demonstrated that the Facility can meet the performance requirements, PGandE may derate the contract capacity pursuant to Section C-4(b).

C-3 SCHEDULED MAINTENANCE

Outage periods for scheduled maintenance shall not exceed 840 hours (35 days) in any 12-month period. This allowance may be used in increments of an hour or longer on a consecutive or nonconsecutive basis. Seller may accumulate unused maintenance hours from one 12-month period to another up to a maximum of 1,080 hours (45 days). This accrued time must be used consecutively and only for major overhauls. Seller shall provide PGandE with the following advance notices: 24 hours for scheduled outages less than one day, one week for a scheduled outage of one day or more (except for major overhauls), and six months for a major overhaul. Seller shall not schedule major overhauls during the peak months (presently June, July and August). Seller shall make reasonable efforts to schedule or reschedule routine maintenance outside the peak months, and in no event shall outages for scheduled maintenance exceed 30 peak hours during the peak months. Seller shall confirm in writing to PGandE pursuant to Article 4, within 24 hours of the original notice, all notices Seller gives personally or by telephone for schedule maintenance.

C-4 ADJUSTMENTS TO CONTRACT CAPACITY

(a) Seller may increase the contract capacity with the approval of PGandE and receive payment for the additional capacity thereafter in accordance with the applicable capacity purchase price published by PGandE at the time the increase is first delivered to PGandE.

(b) Seller may reduce the contract capacity at any time by giving notice thereof to PGandE, subject to the provisions of Appendix D if the reduction occurs after the actual operation date. PGandE may reduce the contract capacity in accordance with Section C-2(e) as a result of appropriate data showing Seller has failed to meet the performance requirements of Section C-2. The amount by which the contract capacity is reduced by PGandE shall be deemed a capacity sale reduction without notice as provided in Section D-3 of Appendix D.

(c) Either Party may request, when it reasonably appears that the capacity of the Facility may have changed for any reason, that a new contract capacity be determined.

C-5 PAYMENT OPTIONS

Seller has two options for calculation of capacity payments and Seller has made its selection in Article 3(a). As used below in this section, month refers to a calendar month. The two options are as follows:

Option 1

When Seller meets the requirements of Section C-2 the monthly payment for capacity will be one-twelfth of the product of the contract capacity price, the contract capacity, the appropriate capacity loss adjustment factor from Table A based on the Facility's interconnection voltage, and the appropriate performance bonus factor, if any, from Table C. Capacity payments will continue during scheduled maintenance outages provided that the provisions of Section C-3 are met.

During a probationary period Seller's monthly payment for capacity shall be determined by substituting for the contract capacity, the capacity at which Seller would have met the performance requirements. In any month during the probationary period that Seller does not meet the performance requirements at whatever capacity was determined for the previous month, Seller's monthly payment for capacity shall be determined by substituting the capacity at which Seller would have met the performance requirements.

The performance bonus factor shall not be applied during a probationary period.

Option 2

The monthly payment for capacity will be the product of the Period Price

Factor (PPF), the Monthly Delivered Capacity (MDC), the appropriate capacity loss adjustment factor from Table A based on the Facility's interconnection voltage, and the appropriate performance bonus factor, if any, from Table C, plus any allowable payment for outages due to scheduled maintenance. Firm capacity prices shall be applied to meter readings taken during the separate times and periods as illustrated in Table B, Appendix B.

The PPF is determined by multiplying the contract capacity price by the following Option 2 Allocation Factors ((1)):

	Option 2 Allocation Factor	x	Contract Capacity Price	=	PPF ($/kW-month)
Seasonal Period A	.18540		_______________		___________
Seasonal Period B	.01043		_______________		___________

((1)) These allocation factors were prescribed by the CPUC in Decision No. 83-12-068. All allocation factors are subject to change by PGandE marginal capacity cost allocation, as determined in general rate case proceedings before the CPUC. Seasonal Periods A and B are defined in Table B, Appendix B.

S.O. #2
May 7, 1984

The MDC is determined in the following manner:

(1) Determine the Performance Factor (P), which is defined as the lesser of 1.0 or the following quantity:

$$P = \frac{A}{C \times (B-S) \times (0.8^*)} \quad (\leq 1.0)$$

Where:

A = Total kilowatt-hours delivered during all on-peak and partial-peak hours excluding any energy associated with generation levels greater than the contract capacity.
C = Contract capacity in kilowatts.
B = Total on-peak and partial-peak hours during the month.
S = Total on-peak and partial-peak hours during the month Facility is out of service on scheduled maintenance.

(2) Determine the Monthly Capacity Factor (MCF), which is computed using the following expression:

$$MCF = P \times \left(1.0 - \frac{M}{D}\right)$$

Where:

M = The number of hours during the month Facility is out of service on scheduled maintenance.
D = The number of hours in the month.

---

* 0.8 reflects a 20% allowance for forced outage.

(3) Determine the MDC by multiplying the MCF by C:

MDC (kilowatts) = MCF x C

The monthly payment for capacity is then determined by multiplying the PPF by the MDC, by the appropriate capacity loss adjustment factor presented from Table A, and by the appropriate performance bonus factor, if any, from Table C.

monthly payment for capacity	=	PPF	x	MDC	x	capacity loss adjustment factor	x	performance bonus factor

Furthermore, the payment for a month in which there is an outage for scheduled maintenance shall also include an amount equal to the produce of the average hourly capacity payment ((1)) for the most recent month in the same type of Seasonal Period (i.e., Seasonal Period A or Seasonal Period B) during which deliveries were made times the number of hours of outage for scheduled maintenance in the current month. Capacity payments will continue during the outage periods for scheduled maintenance provided that the provisions of Section C-3 are met.

During a probationary period, Seller's monthly payment for capacity shall be determined by substituting for the contract capacity, the capacity at which Seller would have met the performance requirements. In

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((1)) Total monthly payment divided by the total number of hours in the monthly billing period.

the event that during the probationary period Seller does not meet the performance requirements at whatever capacity was established for the previous month, Seller's monthly payment for capacity shall be determined by substituting the capacity at which Seller would have met the performance requirements. The performance bonus factor shall not be applied during probationary periods.

TABLE A

If the Facility is non-remote 1 the capacity loss adjustment factors are as follows:

Interconnection Voltage	Capacity Loss Adjustment Factor
Transmission	.989
Primary Distribution	.991
Secondary Distribution	.991

If the Facility is remote the capacity loss adjustment factor is ___________((1)).

((1)) The Seller acknowledges that this blank cannot be filled in at the time of executing this Agreement because the information is not yet available to make a definitive determination of whether the Facility is remote or non-remote and, if remote, the number to be inserted in this blank. Seller shall request PGandE to perform a capacity loss adjustment factor study to be done in its accustomed manner of making such studies to determine whether the Facility is remote or non-remote and, if remote the number to be inserted. If the Facility is determined to be non-remote, N/A shall be inserted.

TABLE B

Firm Capacity Price Schedule
(Levelized $/kW-year)

Actual Operation Date	Term of Agreement									
(Year)	1	2	3	4	5	6	7	8	9	10
1983	72	111	96	88	84	85	88	91	93	96
1984	156	111	95	88	89	92	95	98	100	103
1985	60	58	59	66	73	79	84	88	92	95
1986	56	58	69	78	85	90	95	99	103	106
1987	61	77	88	95	101	105	109	113	117	120
1988	96	104	110	115*	119	122	126	129	133	136

(Year)	11	12	13	14	15	20	25	30
1983	98	100	102	104	106	115	122	128
1984	105	108	110	112	114	124	131	137
1985	99	102	104	107	110	121*	127*	135
1986	110	113	116	118	121	132	141	148
1987	124	127	130	132	135	147	156	163
1988	139	142	145	148	151	163	173	180

---

* In its Application for Rehearing and/or Petition for Modification of CPUC Decision 83-12-068 (dated December 22, 1983) filed on February 6, 1984, PGandE requests correction of three numbers which were incorrectly presented in the Firm Capacity Price Schedule included in that decision (p. 349, Table VI-4). The correct number for 1985 for a 20-year contract life should be $120/kW-yr, and for a 25-year contract life should be $129/kW-yr. The correct number for 1988 for a 4-year contract life should be $115/kW-yr. When the CPUC issues an order correcting these numbers, PGandE shall correct the Firm Capacity Price Schedule accordingly.

TABLE C

Performance Bonus Factor

The following shall be the performance bonus factors applicable to the calculation of the monthly payments for capacity delivered by the Facility after it has demonstrated a capacity factor in excess of 85%.

DEMONSTRATED CAPACITY FACTOR %	PERFORMANCE BONUS FACTOR
85	1.000
90	1.059
95	1.118
100	1.176

After the Facility has delivered power during the span of all of the peak months on the PGandE system (presently June, July and August) in any hear (span),

(i) the capacity factor for each such month shall be calculated in the following manner:

$$\text{CAPACITY FACTOR (\%)} = \frac{F}{(N-W) \times Q} \times 100$$

Where:

For Option 1

F = Total kilowatt-hours delivered by Seller in any peak month during all on-peak hours that Sellers is asked to deliver power to PGandE

excluding any energy associated with generatin levels greater than the contract capacity.

N = Total on-peak hours that Seller is asked to deliver power to PGandE during the month.

W = Total on-peak hours during the peak month that the Facility is out of service on scheduled maintenance during the on-peak hours that Seller is asked to deliver power to PGandE.

Q = Contract capacity in kilowatts.

For Option 2

F = Total kilowatt-hours delivered by Seller in any peak month during all on-peak hours excluding any energy associated with generation levels greater than the contract capacity.

N = Total on-peak hours during the month.

W = Total on-peak hours during the peak month that the Facility is out of service on scheduled maintenance.

Q = Contract capacity in kilowatts.

(ii) the arithmetic average of the above capacity factors shall be determined for that span,

(iii) the average of the above arithmetic average capacity factors for the most recent span(s), not to exceed 5, shall be calculated and shall become the Demonstrated Capacity Factor.

To calculate the performance bonus factor for a Demonstrated Capacity Factor not shown in Table D use the following formula:

$$\text{Performance Bonus Factor} = \frac{\text{Demonstrated Capacity Factor (\%)}}{85\%}$$

THE FOLLOWING SECTIONS SHALL APPLY ONLY TO HYDROELECTRIC PROJECTS

C-6 DETERMINATION OF NATURAL FLOW DATA

Natural flow data shall be based on a period of record of at least 50 years and which includes historic critically dry periods. In the event Seller demonstrates that a natural flow data base of at least 50 years would be unreasonably burdensome, PGandE shall accept a shorter period of record with a corresponding reduction in the averaging basis set forth in Section C-8. Seller shall determine the natural flow data by month by using one of the following methods:

Method 1

If stream flow records are available from a recognized gauging station on the water course being developed in the general vicinity of the project, Seller may use the data from them directly.

Method 2

If directly applicable flow records are not available, Seller may develop theoretical natural flows based on correlation with available flow data for the closest adjacent and similar area which has a recognized gauging station using generally accepted hydrologic estimating methods.

C-7 THEORETICAL OPERATION STUDY

Based on the monthly natural flow data developed under Section C-6 a theoretical operation study shall be prepared by Seller. Such a study shall identify the monthly capacity rating in kW and the monthly energy production in kWh for each month of each year. The study shall take into account all relevant operating constraints, limitations, and requirements including but not limited to --

(1) Release requirements for support of fish life and any other operating constraints imposed on the project;

(2) Operating characteristics of the proposed equipment of the Facility such as efficiencies, minimum and maximum operating levels, project control procedures, etc.;

(3) The design characteristics of project facilities such as head losses in penstocks, valves, tailwater elevation levels, etc.; and

(4) Release requirements for purposes other than power generation such as irrigation, domestic water supply, etc.

The theoretical operation study for each month shall assume an even distribution of generation throughout the month unless Seller can demonstrate that the Facility has water storage characteristics. For the study to show monthly capacity ratings, the Facility shall be capable of operating during all on-peak hours in the peak months on PGandE system, which are presently the months of June, July and August. If the project does not have this capability throughout each such month, the capacity rating in that month of that year shall be set at zero for purposes of this theoretical operation study.

C-8 DETERMINATION OF AVERAGE DRY YEAR CAPACITY RATINGS

Based on the results of the theoretical operation study developed under Section C-7, the average dry year capacity rating shall be established for each month. The average dry year shall be based on the average of the five years of the lowest annual generation as shown in the theoretical operation study. Once such years of lowest annual generation are identified, the monthly capacity rating is determined for each month by averaging the capacity

ratings from each month of those years. The contract capacity shown in Article 2(a) shall not exceed the lowest average dry year monthly capacity ratings for the peak months on the PGandE system, which are presently the months of June, July and August.

C-9 INFORMATION REQUIREMENTS

Seller shall provide the following information to PGandE for its review:

(1) A summary of the average dry year capacity ratings based on the theoretical operation study as provided in Table D;

(2) A topographic project map which shows the location of all aspects of the Facility and locations of stream gauging stations used to determine natural flow data;

(3) A discussion of all major factors relevant to project operation;

(4) A discussion of the methods and procedures used to establish the natural flow data. This discussion shall be in sufficient detail for PGandE to determine that the methods are consistent with those outlined in Section C-6 and are consistent with generally accepted engineering practices; and

(5) Upon specific written request by PGandE, Seller's theoretical operation study.

C-10 ILLUSTRATIVE EXAMPLE

(1) Determine natural flows - These flows are developed based on historic stream gauging records and are compiled by month, for a long-term period (normally at least 50 years or more) which covers dry periods which historically occurred in the 1920's and 30's and more recently in 1976 and 77. In all but unusual situations this will require application of hydrological engineering methods to records that are available, primarily from the USGS publication Water Resources Data for California.

(2) Perform theoretical operation study - Using the natural flow data compiled under (1) above a theoretical operation study is prepared which determines, for each month of each year, energy generation (kWh) and capacity rating (kW). This study is performed based on the Facility's design, operating capabilities, constraints, etc., and should take into account all factors relevant to project operation. Generally such a study is done by computer which routes the natural flows through project features, considering additions and withdrawals from storage, spill past the project, releases for support of fish life, etc., to determine flow available for generation. Then the generation and capacity amounts are computed based on equipment performance, efficiencies, etc.

(3) Determine average dry year capacity ratings - After the theoretical project operation study is complete the five years in which the annual generation (kWh) would have been the lowest are identified. Then for each month, the capacity rating (kW) is averaged for the five years to arrive at a monthly average capacity rating. The contract capacity is then set by the Seller based on the monthly average dry year capacity ratings and the performance requirements of Appendix C. An example project is shown in the attached completed Table D.

EXAMPLE

TABLE D

Summary of Theoretical Operation Study

Project: New Creek 1 Dispatchable: Yes ___ No __X__
Water Source: West Fork New Creek
Mode of Operation: Run of the river
Type of Turbine: Francis Design Flow: 100 cfs Design Head: 150 feet
Operating Characteristics ((1)):

	Flow (cfs)	Head (feet) Gross	Net	Output (kW)	Efficiency (%) Turbine	Generator
Normal Operation	100	160	150	1,120	90	98
Maximum Operation	110	160	148	1,150	85	98
Minimum Operation	30	160	155	290	75	98

Average Dry Year Operation - Based on the average of the following lowest generation years: 1930, 1932, 1934, 1949, 1977.

Month	Energy Generation (kWh)	Capacity Output (kW)	Percent of Total Hours Operated ((2))
January	855,000	1,150	100
February	753,000	1,120	100
March	818,000	1,100	100
April	727,000	1,010	100
May	699,000	940	100
June	612,000	850	100

July	484,000	650	100
August	305,000	410	100
September	245,000	340	100
October	148,800	200	100
November	468,000	650	100
December	595,000	800	100

Maximum Contract Capacity: 410 kW

((1)) If Facility has a variable head, operating curves should be provided.

((2)) For this to be less than 100%, Facility must be dispatchable.

APPENDIX D

ADJUSTMENT OF CAPACITY PAYMENTS
IN THE EVENT OF TERMINATION OR REDUCTION

CONTENTS

APPENDIX D
ADJUSTMENT OF CAPACITY PAYMENTS
IN THE EVENT OF TERMINATION OR REDUCTION

D-1 GENERAL PROVISIONS

(a) This Appendix shall be applicable in the event there is a contract termination or a capacity sale reduction (each sometimes referred to as termination in this Appendix D).

(b) The Parties agree that the amount which PGandE pays Seller for the capacity which Seller makes available to PGandE is based on the agreed value to PGandE of Seller's performance of capacity obligations during the full period of the term of agreement. The Parties further agree that in the event PGandE does not receive such full performance by reason of a termination:

(1) PGandE shall be deemed damaged by reason thereof,

(2) it would be impracticable or extremely difficult to fix the actual damages to PGandE resulting therefrom,

(3) the refunds and payments as provided in Sections D-2 and

D-3, as applicable, are in the nature of adjustments in capacity prices and liquidated damages, and not a penalty, and are fair and reasonable, and

(4) such refunds and payments represent a reasonable endeavor by the Parties to estimate a fair compensation for the reasonable losses that would result from such termination or reduction.

(c) In the event of a capacity sale reduction, the quantity by which the contract capacity is reduced shall be used to calculate the payments due PGandE in accordance with Sections D-2 and D-3, as applicable.

(d) Seller shall be invoiced by PGandE for all refunds and payments due under this Appendix D and the special facilities agreement. From the date of the notice of termination or the date of termination, whichever is earlier, Seller shall pay interest, compounded monthly, on all overdue amounts, at the published Federal Reserve Board three months' Prime Commercial Paper rate.

(e) If Seller does not make payments pursuant to Section D-1(d), PGandE shall have the right to offset any amounts due it against any present or future payments due Seller.

(f) Notices of termination shall be made in accordance with Section A-18 of Appendix A.

D-2 TERMINATION WITH PRESCRIBED NOTICE

In the event Seller terminates this entire Agreement, or all or part of the contract capacity thereof, with the following prescribed written notice:

Amount of Contract Capacity Terminated	Length of Notice Required
1,000 kW or under	3 months
over 1,000 kW through 10,000 kW	9 months
over 10,000 kW through 25,000 kW	12 months
over 25,000 kW through 50,000 kW	36 months
over 50,000 kW through 100,000 kW	48 months
over 100,000 kW	60 months

Then the following provisions shall apply:

(1) With respect to the amount by which the contract capacity is reduced, Seller shall refund to PGandE an amount equal to the difference between (a) the capacity payments already paid by PGandE, based on the original term of agreement and (b) the total capacity payments which PGandE would have paid based on the period of Seller's actual performance using the adjusted capacity price. Additionally, Seller shall pay interest, compounded monthly, on all overpayments, at the published Federal Reserve Board three months' Prime Commercial Paper rate.

(2) From the date PGandE receives the termination notice to the date of actual termination, PGandE shall make capacity payments based on the adjusted capacity price for the amount of contract capacity being terminated.

(3) From the date PGandE receives the termination notice, PGandE shall continue to pay for the amount of contract capacity not being terminated, if any, at the original contract capacity price.

D-3 TERMINATION WITHOUT PRESCRIBED NOTICE

(a) If Seller terminates this Agreement, or all or a part of the contract capacity thereof, without the notice prescribed in Section D-2, the provisions prescribed in Section D-2 will all apply. Additionally:

(b) Seller shall pay PGandE a sum equal to the amount by which the contract capacity is being terminated times the difference between the current firm capacity price on the date of termination for a term equal to the balance of the term of agreement and the contract capacity price, pro-rated for the length of notice given by multiplying by the difference between the prescribed length of notice and the actual notice given, with the difference divided by 12. In the event that the current firm capacity price is less than the contract capacity price, no payment under this Section D-3 shall be due either Party.

This additional payment shall be computed using the following formula:

$$G = CC \times (T - CCP) \times \frac{J - H}{12}$$

Where G >= O

and where:

G = additional payment.
CC = the amount by which the contract capacity is being terminated.
T = the current firm capacity price.
CCP = the contract capacity price.
H = the actual number of months notice given.
J = the prescribed length of notice.

D-4 TERMINATION EXAMPLES

These examples demonstrate how to calculate capacity payment adjustments when capacity sales are terminated.

(a) Termination with Prescribed Notice

(1) Example Based on Option 1

Assumptions:

i. Term of Agreement is 15 years;
ii. Actual operation date is July 1, 1985;
iii. Prescribed notice is given on July 1, 1986;

iv. Contract capacity to be reduced by 10,000 kW on July 1 1987; actual performance to be from July 1, 1985 through July 1, 1987 ((1));

v. The applicable capacity loss adjustment factor is .989; and

vi. No performance bonus for capacity has been earned.

The amount of overpayment (E) made by PGandE to Seller during each monthly billing period is calculated as follows:

E = (A-B) x C x L x U

Where:

A = contract capacity price per month for the actual operation date (July 1, 1985) and the term of agreement which is 15 years = $110/kW-yr / 12 mo/yr = $9.17/kW-mo.

B = adjusted capacity price per month for the actual operation date (July 1, 1984) and a two-year agreement term = $58/kW-hr / 12 mo/yr = $4.83/kW-mo.

___

((1)) The capacity payment is adjusted upon receiving notice, so no refund is necessary for the last month of the first twelve months of operation and all of the second twelve months (June 1, 1986 to July 1, 1987). Seller performed for eleven month prior to payment adjustment. (Note that due to the 30-day interval between delivery and payment, performance in the twelfth month (June 1986) can be paid for at the adjusted capacity price.

C = amount by which the contract capacity is being reduced = 10,000 kW.

L = capacity loss adjustment factor = .989.

U = performance bonus factor; when Seller does not qualify for a performance bonus factor, as in this example, U is removed from the above calculation of E.

Therefore:

E = ($9.17/kW-mo - $4.83/kW-mo) x 10,000 kW x .989 = $42,923 per month.

Table A shows a step-by-step derivation of the refund Seller owes PGandE for the early termination outlined above. The $497,342 that Seller owes PGandE appears at the lower right-hand corner of the table. All other figures of this table represent intermediate calculation steps.

TABLE A

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Monthly Billing Period ((1))	Date of Payment ((2))	Amount of Over-Payment ((3)) $	Accumu-lated Over-Payment ((4)) $	Interest Rate ((5)) %	Interest Charge on Accumulated Overpayment (f)=(d)x(e) ((6)) $	Balance (g) = (c)+(d)+(f) ((7)) $
7/85	8/30/85	42,923	0	1.2	0	42,923
8/85	9/30/85	42,923	42,923	1.0	429	86,275
9/85	10/30/85	42,923	86,275	0.9	776	129,974
10/85	11/30/85	42,923	129,974	0.8	1,040	173,937
11/85	12/30/85	42,923	173,937	0.7	1,218	218,078
12/85	1/30/86	42,923	218,078	0.8	1,745	262,746
1/86	3/ 2/86	42,923	262,746	0.9	2,365	308,034
2/86	3/30/86	42,923	308,034	1.0	3,080	354,037
3/86	4/30/86	42,923	354,037	1.1	3,894	400,854
4/86	5/30/86	42,923	400,854	1.2	4,810	448,587
5/86	6/30/86	42,923	448,587	1.3	5,832	497,342

____

((1)) The month in which power deliveries were made. For purposes of simplification, the monthly billing period will coincide exactly with each calendar month.

((2)) The date on which payment for the monthly billing period state in column (a) is made.

((3)) The amount of overpayment made by PGandE to Seller during each monthly billing period.

((4)) The amount of overpayment accumulated up through last month's date of payment.

((5)) The interest rate for the period between the date of payment for the previous monthly billing period and the date of payment for this monthly billing period. These interest rates are arbitrarily chosen for use in this example.

((6)) The amount of interest charge accrued between the date of payment for the previous monthly billing period and the date of payment for this monthly billing period on the accumulated overpayment balance existing as of the previous monthly billing period's date of payment.

((7)) The amount Seller owes PGandE at this stage of the calculation. The balance (g) for a given monthly billing period equals the accumulated overpayment (d) for the monthly billing period immediately following.

(2) Example Based on Option 2

Assumptions:

i. Term of agreement is 15 years;
ii. Actual operation date is April 1, 1985;
iii. Prescribed notice is given on April 1, 1987;
iv. Contract capacity is reduced by 10,000 kW on April 1, 1988; actual performance is from April 1, 1985 through April 1, 1988((1));
v. Scheduled outage for maintenance: 18 days = 432 hours in both November 1985 and November 1986;
vi. The applicable capacity loss adjustment factor is .989; and
vii. Listed below is Seller's Performance Factor (P), the Demonstrated Capacity Factor (Y) in % (when measured),

and where applicable, the performance bonus factor (U) earned for each of the monthly billing periods((2)) prior to the time capacity payment is adjusted. Also listed below are the number of hours the Facility was out of service for schedule maintenance (M) and the number of hours in the month (D) for each of these months.

((1)) The capacity payment is adjusted upon receiving notice, so no refund is necessary for the last month of the first twenty-four months of operation and all of the last twelve months (March 1, 1987 to April 1, 1988). Seller performed for twenty-three months prior to payment adjustment. (Note that due to the 30-day interval between delivery and payment, performance in the twenty-fourth month (March 1987) can be paid for at the adjusted capacity price.)

((2)) For purposes of simplification, the monthly billing period will coincide exactly with each calendar month.

Monthly Billing Period		P	Y	U	M	D
April	1985	.85	-	-	0	720
May	1985	.95	-	-	0	744
June	1985	.90	80	-	0	720
July	1985	1.00	88	-	0	744
August	1985	.90	96	-	0	744
September	1985	1.00	-	1.035*	0	720
October	1985	.96	-	1.035	0	744
November	1985	.98	-	1.035	432	720
December	1985	1.00	-	1.035	0	744
January	1986	1.00	-	1.035	0	744
February	1986	.92	-	1.035	0	672
March	1986	.85	-	1.035	0	744
April	1986	.78	-	1.035	0	720
May	1986	1.00	-	1.035	0	744
June	1986	.94	100	1.035	0	720
July	1986	.95	95	1.035	0	744
August	1986	1.00	92	1.035	0	744
September	1986	1.00	-	1.080**	0	720
October	1986	.93	-	1.080	0	744
November	1986	.84	-	1.080	432	720
December	1986	.88	-	1.080	0	744
January	1987	.94	-	1.080	0	744
February	1987	1.00	-	1.080	0	672

---

* This performance bonus factor was calculated by averaging the Demonstrated Capacity Factors for each of the months of June, July and August 1985, and then dividing that average by 85(%):

$$U = \frac{80 + 88 + 96}{3} / 85 = 1.035$$

** This performance bonus factor was calculated by averaging the Demonstrated Capacity Factors for each of the months of June, July and August 1985, and June, July and August 1986, and then dividing that average by 85(%):

$$U = \frac{80 + 88 + 96 + 100 + 95 + 92}{6} / 85 = 1.080$$

The amount of overpayment (E) made by PGandE to Seller during each monthly billing period is calculated as follows:

$$E = [P \times \frac{(1 - M)}{D} \times K \times L \times U \times (A - B) \times C] + [\frac{M}{D} \times R]$$

Where:

P = performance factor.

M = number of hours of scheduled maintenance for that monthly billing period.

D = number of hours in that monthly billing period.

K = allocation factor from Section C-5.

L = capacity loss adjustment factor = .989.

U = performance bonus factor; when Seller does not qualify for a performance bonus factor, U is removed from the above calculation of E.

A = Contract capacity price for the actual operation date (April 1, 1985) and term of agreement which is 15 years = $110/kW-yr.

B = adjusted capacity price for the actual operation date and a three-year agreement term = $59/kW-yr.

C = amount by which the contract capacity is being reduced = 10,000 kW.

R = amount of overpayment for the most recent monthly billing period in the same Seasonal Period (i.e., Seasonal Period A or Seasonal Period B).

The results of the calculations are:

Monthly Billing Period		Amount of Overpayment (E)
April	1985	$ 4,472
May	1985	88,838
June	1985	84,163
July	1985	93,514
August	1985	84,163
September	1985	96,787
October	1985	5,227
November	1985	5,271
December	1985	5,445
January	1986	5,445
February	1986	5,009
March	1986	4,628
April	1986	4,247
May	1986	96,787
June	1986	90,980
July	1986	91,948
August	1986	96,787
September	1986	100,995
October	1986	5,284
November	1986	5,079
December	1986	5,000
January	1987	5,341
February	1987	5,682

Table B shows a step-by-step derivation of the refund Seller owes PGandE for the early termination outlined above. The $1,136,015 that Seller owes PGandE appears at the lower right-hand corner of the table. All other figures of this table represent intermediate calculation steps.

TABLE B

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Monthly Billing Period ((1))	Date of Payment ((2))	Amount of Over-Payment ((3)) $	Accumu-lated Over-Payment ((4)) $	Interest Rate ((5)) %	Interest Charge on Accumulated Overpayment (f)=(d)x(e) ((6)) $	Balance (g) = (c)+(d)+(f) ((7)) $
4/85	5/30/85	4,472	0	1.3	0	4,472
5/85	6/30/85	88,838	4,472	1.4	63	93,373
6/85	7/30/85	84,163	93,373	1.3	1,214	178,750
7/85	8/30/85	93,514	178,750	1.2	2,145	274,409
8/85	9/30/85	84,163	274,409	1.0	2,744	361,316
9/85	10/30/85	96,787	361,316	0.9	3,252	461,355
10/85	11/30/85	5,227	461,355	0.8	3,691	470,273
11/85	12/30/85	5,271	470,273	0.7	3,292	478,836
12/85	1/30/86	5,445	478,836	0.8	3,831	488,112
1/86	3/ 2/86	5,445	488,112	0.9	4,393	497,950
2/86	3/30/86	5,009	497,950	1.0	4,980	507,939
3/86	4/30/86	4,628	507,939	1.1	5,587	518,154
4/86	5/30/86	4,247	518,154	1.2	6,218	528,619
5/86	6/30/86	96,787	528,619	1.3	6,872	632,278
6/86	7/30/86	90,980	632,278	1.4	8,852	732,110
7/86	8/30/86	91,948	732,110	1.4	10,250	834,308
8/86	9/30/86	96,787	834,308	1.3	10,846	941,941
9/86	10/30/86	100,995	941,941	1.2	11,303	1,054,239
10/86	11/30/86	5,284	1,054,239	1.0	10,542	1,070,065
11/86	12/30/86	5,079	1,070,065	1.1	11,771	1,086,915
12/86	1/30/87	5,000	1,086,915	1.1	11,956	1,103,871
1/87	3/ 2/87	5,341	1,103,871	1.0	11,039	1,120,251
2/87	3/30/87	5,682	1,120,251	0.9	10,082	1,136,015

((1)) The month in which power deliveries were made. For purposes of simplification, the monthly billing period will coincide exactly with each calendar month.

((2)) The date on which payment for the monthly billing period stated in column (a) is made.

((3)) The amount of overpayment made by PGandE to Seller during each monthly billing period.

((4)) The amount of overpayment accumulated up through last month's date of payment.

((5)) The interest rate for the period between the date of payment for the previous monthly billing period and the date of payment for this monthly billing period. These interest rates are arbitrarily chosen for use in this example.

((6)) The amount of interest charge accrued between the date of payment for the previous monthly billing period and the date of payment for this monthly billing period on the accumulated overpayment balance existing as of the previous monthly billing period's date of payment.

((7)) The amount Seller owes PGandE at this stage of the calculation. The balance (g) for a given monthly billing period equals the accumulated overpayment (d) for the monthly billing period immediately following.

(b) Termination without Prescribed Notice

If Seller terminates without prescribed notice, Seller will owe PGandE a refund [the calculation of which is described in Sections D-4(a)(1) and D-4(a)(2) of this example] and payment (G). This example demonstrates how the payment (G) is calculated. Assumptions:

i. Term of agreement is 15 years;
ii. Actual operation date is July 1, 1985;
iii. Notice is given on January 1, 1990; and
iv. Contract capacity is to be reduced by 10,000 kW on July 1, 1990; actual performance is from July 1, 1985 through July 1, 1990.

The payment (G) is calculated as follows:

$$(G) = CC \times (T-CCP) \times \frac{J-H}{12} \quad G >= O$$

Where:

CC = The amount of contract capacity being terminated = 10,000 kW.
T = the current firm capacity price $140/kW-yr is arbitrarily chosen for use in this example for a July 1, 1990 Operation Date and 10-year agreement term.
CCP = the contract capacity price = $110/kW-yr.
H = the actual number of months notice given = six months.
J = the prescribed notice = twelve months.

The sample calculation is:

$$G = CC \times (T - CCP) \times \frac{(J-H)}{12}$$

$$G = 10{,}000 \text{ kW} \times (\$140/\text{kW-yr} - \$110/\text{kW-yr}) \times \frac{(12 \text{ mos.} - 6 \text{ mos.})}{12 \text{ mos./yr}}$$

G = $150,000

APPENDIX E

INTERCONNECTION

CONTENTS

S.O. #2
May 7, 1984

E-1

E-1   INTERCONNECTION TARIFFS

(The applicable tariffs in effect at the time of execution of this Agreement shall be attached.)

S.O. #2
May 7, 1984

E-2

E-2   POINT OF DELIVERY LOCATION SKETCH

The Seller requests, and PGandE consents, that the location sketch not be made at the time of executing the Agreement, because the Seller, recognizing that the information is not yet available to make a definitive determination of the sketch to be inserted here, shall request PGandE to perform an interconnection study to be done in its accustomed manner of making such studies to determine the sketch to be inserted.

S.O. #2
May 7, 1984

E-3

E-3   INTERCONNECTION FACILITIES FOR WHICH SELLER IS RESPONSIBLE

The Seller requests, and PGandE consents, that this listing of facilities not be filled in at the time of executing the Agreement, because the Seller, recognizing that the information is not yet available to make a definitive determination of the listing of facilities to be inserted here, shall request PGandE to perform an interconnection study to be done in its accustomed manner of making such studies to determine the listing of facilities to be inserted.

S.O. #2
May 7, 1984

FIRST AMENDMENT TO POWER PURCHASE
AGREEMENT FOR FIRM CAPACITY AND ENERGY
BETWEEN UNIVERSITY COGENERATION, INC., AND
PACIFIC GAS AND ELECTRIC COMPANY

This First Amendment is entered into as of the 17th day of October, 1985, between University Cogeneration, Inc., a California corporation, ("Seller"), and Pacific Gas and Electric Company, a California corporation, ("PGandE"), with reference to the following:

A. Seller and PGandE are parties to that certain Power Purchase Agreement for Firm Capacity and Energy dated April 23, 1985 (the Power Purchase Agreement);

B. It has come to the attention of Seller and PGandE that Seller's corporate name was incorrectly set forth in the Power Purchase Agreement as University Cogeneration Inc., 1985-1 when it should have been set forth as University Cogeneration, Inc.; and

C. Seller and PGandE wish to amend the Power Purchase Agreement to correctly set forth Seller's corporate name.

NOW, THEREFORE, in consideration of the mutual agreements contained in the Power Purchase Agreement and herein, the parties agree as follows:

1. Effective from the execution date of the Power Purchase Agreement, such agreement is amended to the extent that all references to Seller as University Cogeneration Inc., 1985-1 shall be deemed to be references to Seller as University Cogeneration, Inc.

IN WITNESS WHEREOF the parties have caused this Amendment to be signed.

UNIVERSITY COGENERATION, INC.

Date Signed: October 16, 1985

By: /s/ John R. Zanot
Name: John R. Zanot
Title: Vice President

PACIFIC GAS AND ELECTRIC COMPANY

Date Signed: October 17, 1985

By: /s/ Nolan H. Daines
Name: Nolan H. Daines
Title: Vice President

SECOND AMENDMENT TO
POWER PURCHASE AGREEMENT
FOR FIRM CAPACITY AND ENERGY
BETWEEN UNIVERSITY COGENERATION, INC., AND
PACIFIC GAS AND ELECTRIC COMPANY
DATED APRIL 23, 1985

On April 23, 1985 PACIFIC GAS AND ELECTRIC COMPANY ("PGandE") and UNIVERSITY COGENERATION, INC. ("Seller") entered into a Standard offer No. 2 Power Purchase Agreement ("Agreement") for the 38,000 kW cogeneration project located at Section 28, Township 12 north, Range 24 west, 1/2 miles south of Taft, Kern County, California.

PGandE and Seller in consideration of the mutual agreements herein, and other good and valuable considerations, hereby amend said Agreement as follows:

1. ARTICLE 2 - PURCHASE OF POWER

Paragraph (a) - The blank in the first sentence is replaced with 115 kV to reflect the energy delivery voltage level:

"(a) Seller shall sell and deliver and PGandE shall purchase and accept delivery of firm capacity and energy at the voltage level of 115 kV as indicated below

Paragraph (d) - The blank in this paragraph is replaced with 46.7 MVA to reflect the physical limitations of the project interconnection facilities:

"(d) To avoid exceeding the physical limitations of the interconnection facilities., Seller shall limit the Facility's actual rate of delivery into the PGandE system to 46.7 MVA."

Paragraph (g) - The blank in this paragraph is replaced with "not applicable" to reflect the fact that the meters have been placed on PGandE's side of the transformer:

"(g) The transformer loss adjustment factor is not applicable."

2. Appendix C - FIRM CAPACITY PRICE SCHEDULE

Section C-5, Table A, page C-11 - The sentence following this table shall be replaced with the following:

"The Facility is non-remote and the capacity loss adjustment factor is 0.989."

3. Appendix E - INTERCONNECTION

The entire appendix shall be replaced- by the following to include the Electric Rule No. 21 in effect at the time of execution of the Agreement,the Point of Delivery Location sketch and the List of Interconnection Facilities for which Seller is Responsible:

APPENDIX E
INTERCONNECTION
CONTENTS

E-1 INTERCONNECTION TARIFFS

(The applicable tariffs in effect at the time of execution of this Agreement shall be attached.

THIRD AMENDMENT

TO THE
FIRM CAPACITY AND ENERGY
POWER PURCHASE AGREEMENT
BETWEEN
UNIVERSITY COGENERATION, INC.
AND
PACIFIC GAS AND ELECTRIC COMPANY

THIS THIRD AMENDMENT is by and between UNIVERSITY COGENERATION INC. ("Seller"), and PACIFIC GAS AND ELECTRIC COMPANY ("PG&E"), a California corporation. It amends the Firm capacity and Energy Power Purchase Agreement signed on April 23, 1985 by PG&E and on April 16, 1985 by University Cogeneration, Inc. for the 38,000 kW cogeneration facility located at Section 28, Township 12N., Range 24W, 3-1/2 miles South of Taft, Kern County, California (the "Agreement"). PG&E and Seller are sometimes referred to herein collectively as the "Parties".

WHEREAS, by letter dated June 2, 1988, Seller notified PG&E that it elected to decrease the contract firm capacity to 32,000 kW, in accordance with Section C-4(b), Appendix C, of the Agreement; and

WHEREAS, the Parties desire to amend the Agreement to reflect the foregoing.

NOW, THEREFORE, in consideration of the mutual covenants and agreements contained herein, PG&E and Seller hereby agree as follows:

1. The term "34,000 kW" shall be deleted from page 4, line 6, Article 2(a), PURCHASE OF POWER, of the Agreement and replaced by the term "32,000 kW".

2. All other provisions of the Agreement remain unchanged.

3. All underlined terms used herein shall have the same meanings as defined in the Agreement.

4. This Third Amendment shall be construed and interpreted in accordance with the laws of the State of California, excluding any choice of law rules that may direct the application of the laws of another jurisdiction.

IN WITNESS WHEREOF, the Parties hereto have caused this Third Amendment to be signed by their authorized representatives, and it is effective as of the last date set written below.

UNIVERSITY COGENERATION, INC.	PACIFIC GAS AND ELECTRIC COMPANY
BY: /s/ L.M. Gunderson	By: /s/ Junona A. Jonas
Name: L.M. Gunderson	Name: Junona A. Jonas
Title: Vice President	Title: Manager, QF Contracts
Date Signed: April 26, 1989	Date Signed: May 19, 1989

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 No. 33-23326 and 33-61337) of our report dated February 21, 1996 on our audits of the financial statements of Berry Petroleum Company as of December 31, 1995 and 1994 and for the three years in the period ended December 31, 1995, which report is included in this Annual Report on Form 10-K.

/s/ Coopers & Lybrand L.L.P.
COOPERS & LYBRAND L.L.P.

Los Angeles, California
March 14, 1996

CONSENT OF INDEPENDENT PETROLEUM ENGINEERING CONSULTANT

The undersigned, an independent petroleum engineering consultant, hereby consents to incorporation by reference in the Registration Statements No. 33-23326 and No. 33-61337 on Form S-8 of Berry Petroleum Company and the related Prospectus of our reserve report prepared pursuant to the Securities Exchange Act of 1934 dated January 26, 1994, pertaining to interests of Berry Petroleum Company and subsidiaries in certain oil and gas properties located in California, and the use of the name Babson and Sheppard Petroleum Engineers as the independent petroleum engineering firm that prepared such report for the year ended December 31, 1993 which report is referenced in the December 31, 1995 Annual Report on Form 10-K of Berry Petroleum Company.

Dated: March 4, 1996

BABSON AND SHEPPARD PETROLEUM ENGINEERS

By: /s/ John F. Bergquist
John F. Bergquist, President

Exhibit 23.2

DEGOLYER AND MACNAUGHTON
ONE ENERGY SQUARE
DALLAS, TEXAS 75206

March 1, 1996

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

Gentlemen:

In connection with the Annual Report on Form 10-K for the fiscal year ended December 31, 1995, (the Annual Report) of Berry Petroleum Company (the Company), we hereby consent to (i) the use of and reference to our report dated February 12, 1996, entitled "Appraisal Report as of December 31, 1995 on Certain Property Interests owned by Berry Petroleum Company, "our report dated February 23, 1995, entitled "Appraisal Report as of December 31, 1994 on Certain Properties owned by Berry Petroleum Company," and our report dated March 4, 1994, entitled "Appraisal Report as of December 31, 1993 on Certain Properties owned by Berry Petroleum Company" (collectively referred to as the "Reports "), all three of which pertain to interests of the Company in certain oil and gas properties located in California, Louisiana, Nevada, and Texas, under the caption "Oil and Gas Reserves - Reserve Reports" in items 1 and 2 of the Annual Report, in item 6 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 reserves estimates set forth in the report dated March 4, 1994, have been combined with reserves estimates of other petroleum consultants and the engineering staff of the Company, we are necessarily unable to verify the accuracy of the reserves values, as of December 31, 1993, contained in the Annual Report and, 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,

/s/ DeGolyer and MacNaughton
DEGOLYER and MacNAUGHTON

Exhibit 23.3

THIS SCHEDULE CONTAINS SUMMARY FINANCIAL INFORMATION EXTRACTED FROM THE
DECEMBER 31, 1995 FORM 10-K AND IS QUALIFIED IN ITS ENTIRETY BY REFERENCE
TO SUCH FINANCIAL STATEMENTS.

0000778438
BERRY PETROLEUM COMPANY
1,000

YEAR
DEC-31-1995
DEC-31-1995
18,759
15,695
8,414
0
0
45,200
138,745
66,703
117,722
8,694
0
0
0
219
91,841
117,722
45,773
51,190
0
26,630
5,071
0
0
19,489
7,286
12,203
0
0
0
12,203
.56
.56

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. 33-23326 and No. 33-61337 filed on July 28, 1988 and July 27, 1995, respectively):

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