BP PLC
Form 20-F
March 28, 2002

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

FORM 20-F

(Mark One)

[ ] REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) or (g) OF THE SECURITIES EXCHANGE ACT OF 1934

OR

[x] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2001

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission file number 1-6262

BP p.l.c.

(Exact name of Registrant as specified in its charter)

ENGLAND and WALES

(Jurisdiction of incorporation or organization)

Britannic House
1 Finsbury Circus
London EC2M 7BA
England

(Address of principal executive offices)

Securities registered or to be registered pursuant to Section 12(b) of the Act.

Title of each class	Name of each exchange on which registered
Ordinary Shares of 25c each	Chicago Stock Exchange* New York Stock Exchange* Pacific Exchange, Inc.*

*Not for trading, but only in connection with the registration of American Depositary Shares, pursuant to the requirements of the Securities and Exchange Commission

Securities registered or to be registered pursuant to Section 12(g) of the Act.

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.

None

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

Ordinary Shares of 25c each	22,432,076,754
Cumulative First Preference Shares of (pound)1 each	7,232,838
Cumulative Second Preference Shares of (pound)1 each	5,473,414

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 which financial statement item the Registrant has elected to follow.

Item 17 Item 18 x

TABLE OF CONTENTS

CERTAIN DEFINITIONS

Unless the context indicates otherwise, the following terms have the meanings shown below.

Oil and natural gas reserves

'Proved reserves' -- Estimated quantities of crude oil or 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, that is prices and costs as of the date the estimate is made.

'Proved developed reserves' -- Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing natural forces and mechanisms of primary recovery are included as 'proved developed reserves' only after testing by a pilot project or after the operation of an installed programme has confirmed through production response that increased recovery will be achieved.

'Proved undeveloped reserves' -- Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances are estimates of proved undeveloped reserves attributable to acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Miscellaneous terms

'ADR' -- American Depositary Receipt.

'ADS' -- American Depositary Share.

'Amoco' -- The former Amoco Corporation and its subsidiaries.

'ARCO' -- Atlantic Richfield Company and its subsidiaries.

'Associated undertaking' -- An undertaking in which the BP Group has a participating interest and over whose operating and financial policy the BP Group exercises a significant influence (presumed to be the case where 20% or more of the voting rights are held) and which is not a subsidiary undertaking.

'Barrel' -- 42 US gallons.

'Billion' -- 1,000,000,000.

'BP', 'BP Group' or the 'Group' -- BP p.l.c. and its subsidiaries.

'Burmah Castrol' -- Burmah Castrol plc and its subsidiaries.

'Cent' or 'c' -- One hundredth of the US dollar.

The 'Company' -- BP p.l.c.

'Crude oil' -- Includes condensate and natural gas liquids.

'Dollar' or '$' -- The US dollar.

'FSA' -- Financial Services Authority.

'Gas' -- Natural Gas.

'LNG' -- Liquefied Natural Gas.

'London Stock Exchange' or 'LSE' -- London Stock Exchange Limited.

'LPG' -- Liquefied Petroleum Gas.

'NGL' -- Natural Gas Liquid.

'Noon Buying Rate' -- The noon buying rate in New York City for cable transfers in pounds as certified for customs purposes by the Federal Reserve Bank of New York.

'North America' -- the USA and Canada.

'OECD' -- Organization for Economic Cooperation and Development.

'Oil' -- Crude oil, condensate and natural gas liquids.

'OPEC' -- The Organization of Petroleum Exporting Countries.

'Ordinary Shares' -- Ordinary fully paid shares in BP p.l.c. of 25c each.

'Pence' or 'p' -- One hundredth of a pound.

'Pound', 'sterling' or '(pound)' -- The pound sterling.

'Preference Shares' -- Cumulative First Preference Shares and Cumulative Second Preference Shares in BP p.l.c. of(pound)1 each.

'Subsidiary undertaking' -- An undertaking in which the BP Group holds a majority of the voting rights.

'Tonne' or 'metric ton' -- 2,204.6 pounds.

'Trillion' -- 1,000,000,000,000.

'UK' -- United Kingdom of Great Britain and Northern Ireland.

'UK GAAP' -- Generally Accepted Accounting Practice in the UK.

'Undertaking' -- A body corporate, partnership or an unincorporated association, carrying on a trade or business.

'US' or 'USA' -- United States of America.

'US GAAP' -- Generally Accepted Accounting Principles in the USA.

'Vastar' -- Vastar Resources Inc. and its subsidiaries.

PART I

ITEM 1 -- IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISORS

Not applicable.

ITEM 2 -- OFFER STATISTICS AND EXPECTED TIMETABLE

Not applicable.

ITEM 3 -- KEY INFORMATION

SELECTED FINANCIAL INFORMATION

Summary

This information has been extracted or derived from the audited financial statements of the BP Group presented elsewhere herein or otherwise included with BP p.l.c.'s Annual Reports on Form 20-F for the relevant years which have been filed with the Securities and Exchange Commission, as reclassified to conform with the accounting presentation adopted in this annual report.

	Years ended December 31,				
	2001	2000	1999	1998	1
	($ million except per share amounts)				
UK GAAP					

Income statement data					
Turnover......................................	175,389	161,826	101,180	83,732	108,
Less:joint ventures..........................	1,171	13,764	17,614	15,428	16,
Group turnover................................	174,218	148,062	83,566	68,304	91,
Total replacement cost operating profit (a)...	16,135	17,756	8,894	6,521	10,
Replacement cost profit before exceptional items (b)....................	9,880	11,214	5,330	3,959	6,
Profit for the year..........................	8,010	11,870	5,008	3,220	5,
Per ordinary share (c): (cents)					
Profit for the year:					
Basic......................................	35.70	54.85	25.82	16.77	29
Diluted....................................	35.48	54.48	25.68	16.70	29
Dividends (d).............................	22.00	20.50	20.00	19.75	18
Average number outstanding of 25 cents ordinary shares (shares million)..........	22,436	21,638	19,386	19,192	19,
Balance sheet data					
Total assets..................................	141,158	143,938	89,561	84,915	86,
Net assets....................................	74,994	74,001	44,342	43,573	43,
Share capital.................................	5,629	5,653	4,892	4,863	4,
BP shareholders' interest....................	74,367	73,416	43,281	42,501	42,
Finance debt due after more than one year.....	12,327	14,772	9,644	9,641	8,
Debt to borrowed and invested capital (e).....	14%	17%	18%	18%	
Other data					
Per ordinary share: (cents)					
Replacement cost profit before exceptional items........................	44.03	51.82	27.48	20.62	34.
Net cash inflow from operating activities (f).	22,409	20,416	10,290	9,586	15,5
Net cash outflow from capital expenditure acquisitions and disposals.................	11,604	6,207	5,142	6,520	10,0

	Years ended December 31,				
	2001	2000	1999	1998	1
	($ million except per share amounts)				
US GAAP					
Income statement data					
Revenues......................................	174,218	148,062	83,566	68,304	91,
Profit for the period........................	4,164	10,183	4,596	2,826	5,
Comprehensive income.........................	2,569	7,562	3,674	2,848	4,
Profit per ordinary share (c)(g): (cents)					
Basic....................................	18.55	47.05	23.70	14.72	29
Diluted..................................	18.44	46.74	23.56	14.66	29
Profit per American Depositary Share (c)(g): (cents)					
Basic....................................	111.30	282.30	142.20	88.32	177
Diluted..................................	110.64	280.44	141.36	87.96	176
Balance sheet data					
Total assets..................................	146,244	152,236	90,342	85,538	87,
BP shareholders' interest....................	62,322	65,554	37,838	37,334	37,

Other data					
Net cash used in investing activities.........	11,685	6,326	4,922	6,861	10,
Net cash used in financing activities.........	5,853	7,852	3,332	2,161	3,

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(a) Operating profit is a UK GAAP measure of trading performance. It excludes profits and losses on the sale of fixed assets and businesses or termination of operations and fundamental restructuring costs, interest expense and taxation.

BP determines operating profit on a replacement cost basis, which eliminates the effect of inventory holding gains and losses. For the oil and gas industry, the price of crude oil can vary significantly from period to period; hence the value of crude oil (and products) also varies. As a consequence, the amount that would be charged to cost of sales on a first-in, first-out (FIFO) basis of inventory valuation would include the effect of oil price fluctuations on oil and products inventories. BP therefore charges cost of sales with the average cost of supplies incurred during the period rather than the historical cost of supplies on a FIFO basis. For this purpose, inventories at the beginning and end of the period are valued at the average cost of supplies incurred during the period rather than at their historical cost. These valuations are made quarterly by each business unit, based on local oil and product price indices applicable to their specific inventory holdings, following a methodology that has been consistently applied by BP for many years. Operating profit on the replacement cost basis and a derivative measure, that is, profit adjusted for depreciation and amortization arising from the fixed asset revaluation adjustment and goodwill consequent upon the ARCO and Burmah Castrol acquisitions, and adjusted for special items (non-recurring charges and credits that are not classified as exceptional under UK GAAP), are used by BP management as the primary measures of business unit trading performance and BP management believes that these measures assist investors to assess BP's underlying trading performance from period to period.

Replacement cost is not a US GAAP measure. The major US oil companies apply the last-in, first-out (LIFO) basis of inventory valuation. The LIFO basis is not permitted under UK GAAP. The LIFO basis eliminates the effect of price fluctuations on crude oil and product inventory except where an inventory drawdown occurs in a period. BP management believes that where inventory volumes remain constant or increase in a period, operating profit on the LIFO basis will not differ materially from operating profit on BP's replacement cost basis.

Where an inventory drawdown occurs in a period, cost of sales on a LIFO basis will be charged with the historical cost of the inventory drawn down, whereas BP's replacement cost basis charges cost of sales at the average cost of supplies for the period. To the extent that the historical cost on the LIFO basis of the inventory drawn down is lower than the current cost of supplies in the period, operating profit on the LIFO basis will be greater than operating profit on BP's replacement cost basis. To the extent that the historical cost on the LIFO basis of the inventory drawdown is greater than the current cost of supplies in the period, operating profit on the LIFO basis will be lower than operating profit on BP's replacement cost basis.

(b) Replacement cost profit before exceptional items excludes profits and losses on the sale of fixed assets and businesses or termination of operations and fundamental restructuring costs, which are defined by UK GAAP. This measure and a derivative measure, that is, profit adjusted for depreciation and amortization arising from the fixed asset revaluation adjustment and goodwill consequent upon the ARCO and Burmah Castrol acquisitions, and adjusted for special items (non-recurring charges and credits that are not classified as exceptional under UK GAAP), are used by the BP board in setting targets for and monitoring performance within the Group. BP's management believes these indicators provide the most relevant and useful measures for investors because they most accurately reflect underlying trading performance.

6

(c) With effect from October 4, 1999 BP split (or subdivided) its ordinary share capital. As a result, the number of ordinary shares held at the close of business on Friday October 1, 1999, doubled, and holders of ADSs received a two-for-one stock split. Comparative figures for 1997 and 1998 have been changed accordingly.

(d) BP dividends per share represent historical dividends per share paid by The British Petroleum Company p.l.c., for 1997 and 1998.

(e) Finance debt due after more than one year, compared with such debt plus BP and minority shareholders' interests.

(f) The net cash inflows from operating activities are presented in accordance with the requirements of Financial Reporting Standard No. 1 (Revised 1996) issued by the UK Accounting Standards Board. For a cash flow statement prepared on a US GAAP basis see Item 18 -- Financial Statements -- Note 43.

(g) FASB Statement of Financial Accounting Standards No. 128 -- 'Earnings per Share' (SFAS 128) was adopted for the accounting period ending December 31, 1997.

(h) The Group adopted Financial Reporting Standard No. 12 'Provisions, Contingent Liabilities and Contingent Assets' with effect from January 1, 1999. Comparative figures for 1997 and 1998 have been changed accordingly.

Exchange Rates

The following table sets forth, for the periods and dates indicated, certain information concerning the Noon Buying Rate for the pound in New York City for cable transfers in pounds as certified for customs purposes by the Federal Reserve Bank of New York. This is expressed in dollars per (pound)1.

	At period end	Average(a)	High	Low
Year ended December 31,				
1997	1.63	1.64	1.70	1.58
1998	1.66	1.66	1.72	1.61
1999	1.62	1.61	1.68	1.55
2000	1.50	1.51	1.65	1.40
2001	1.45	1.44	1.50	1.37
Month of				
September 2001	1.47	1.46	1.47	1.44
October 2001	1.45	1.45	1.48	1.42
November 2001	1.43	1.44	1.47	1.41
December 2001	1.45	1.44	1.46	1.42
January 2002	1.41	1.43	1.45	1.41
February 2002	1.41	1.42	1.43	1.41

March 2002 (through March 26)..................	1.43	1.42	1.43	1.41

(a) The average of the Noon Buying Rates on the last day of each month during the calendar year or, in the case of monthly averages, the average of all days in the month.

(b) The Noon Buying Rate on March 26, 2002 was $1.43 = (pound)1.

7

Dividends

BP has paid dividends on its Ordinary Shares in each year since 1917. In 2000 and thereafter, dividends were, and are expected to continue to be, paid quarterly in March, June, September and December. Until their shares have been exchanged for BP ADSs, Amoco and ARCO shareholders do not have the right to receive dividends.

At least until December 31, 2003, BP will announce dividends for Ordinary Shares in US dollars and state an equivalent pounds sterling dividend. Dividends on BP ordinary shares will be paid in pounds sterling and on BP ADSs in US dollars. Prior to the fourth quarterly dividend of 1998 The British Petroleum Company p.l.c. announced dividends in sterling. Foreign exchange rates may affect dividends paid. However, when setting the dividend the directors are mindful of dividend fluctuation in sterling terms.

The following table shows dividends announced by the Company per ADS for each of the past five years, together with the 'refund' but before deduction of withholding taxes as described in Item 10 -- Additional Information -- Taxation. Refund means an amount equal to the tax credit available to individual shareholders resident in the UK in respect of such dividend, less a withholding tax equal to 15% (but limited to the amount of the tax credit) of the aggregate of such tax credit and such dividend. Dividends have been translated from pounds per ADS up to and including the third quarterly dividend for 1998, and from dollars per ADS for the fourth quarterly dividend of 1998 and thereafter, at an exchange rate in London on the business day last preceding the day when the directors announced their intention to pay the quarterly dividends for those years.

		Quarterly				
Dividends per American Depositary Share (a)(b)		First	Second	Third	Fourth	Total
1997.........................	UK pence	19.7	20.6	20.7	21.5	82.5
	US cents	31.9	33.6	34.6	35.3	135.4
	Can. cents	44.1	46.4	48.6	50.5	189.6
1998.........................	UK pence	21.5	22.5	22.5	23.0	89.5
	US cents	36.0	36.5	37.5	33.4	143.4
	Can. cents	51.4	55.3	57.8	50.0	214.5

1999.........................	UK pence	20.5	20.8	20.2	20.8	82.3
	US cents	33.3	33.3	33.3	33.4	133.3
	Can. cents	48.7	50.1	48.6	48.5	195.9
2000.........................	UK pence	21.5	22.3	24.0	24.1	91.9
	US cents	33.3	33.3	35.0	35.0	136.6
	Can. cents	49.7	49.8	53.6	53.2	206.3
2001.........................	UK pence	24.4	26.1	25.4	27.0	102.9
	US cents	35.0	36.7	36.7	38.3	146.7
	Can. cents	53.7	56.0	58.5	61.0	229.2

(a) With effect from June 6, 1997 the Company split existing ADSs on a two-for-one basis so that an ADS is now equivalent to six BP ordinary shares.

(b) With effect from October 4, 1999 BP split (or subdivided) its ordinary share capital. As a result, the number of BP ordinary shares held at the close of business on Friday October 1, 1999, doubled, and holders of ADSs received a two-for-one stock split. Comparative figures for 1997 and 1998 have been changed accordingly.

The share dividend plan, whereby holders of BP ordinary shares could elect to receive new shares (out of unissued share capital) instead of cash dividends at a rate equivalent to the sum of the net cash dividend and related tax credit, was withdrawn following the third quarterly 1998 dividend.

A dividend reinvestment plan was introduced with effect from the fourth quarterly 1998 dividend, whereby holders of BP ordinary shares can elect to reinvest the net cash dividend in shares purchased on the London Stock Exchange. This plan is not available to any person resident in the USA or Canada, or in any jurisdiction outside the UK where such an offer requires compliance by the Company with any governmental or regulatory procedures or any similar formalities.

A dividend reinvestment plan is, however, available for holders of ADSs through JPMorgan Chase Bank (formerly known as Morgan Guaranty Trust Company).

Future dividends will be dependent upon future earnings, the financial condition of the Group, the Risk Factors set out below, and other matters which may affect the business of the Group set out in Item 5 -- Operating and Financial Review and Prospects.

RISK FACTORS

There is strong competition, both within the oil industry and with other industries, in supplying the fuel needs of commerce, industry and the home.

The oil industry is particularly subject to regulation and intervention by governments throughout the world in such matters as the award of exploration and production interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and decommissioning of a field (including restrictions on production) and, possibly, nationalization, expropriation or cancellation of contract rights.

The oil industry is also subject to the payment of royalties and taxation, which tend to be high compared with those payable in respect of other commercial activities.

Exploration and production require high levels of investment and have particular economic risks and opportunities. They are subject to natural hazards and other uncertainties including those relating to the physical characteristics of an oil or natural gas field.

Oil prices are subject to international supply and demand. Political developments (especially in the Middle East) and the outcome of meetings of OPEC can particularly affect world oil supply and oil prices.

Natural gas prices are subject to regional supply and demand. Prices can fluctuate significantly.

Refining profitability can be volatile with both oversupply and periodic supply tightness in various regional markets.

The marketing of petroleum and related products, especially to retail customers, can be affected by intense competition.

Crude oil prices are generally set in dollars while sales of refined products may be in a variety of currencies. Fluctuation in exchange rates can therefore give rise to foreign exchange exposures.

Sectors of the chemicals industry are also subject to fluctuations in supply and demand within the chemicals market, with consequent effect on prices and profitability, and to governmental regulation and intervention in such matters as safety and environmental controls.

In addition to the adverse effect on revenues, margins and profitability from any future fall in oil and natural gas prices, a prolonged period of low prices or other indicators would lead to a review for impairment of the Group's oil and natural gas properties. This review would reflect management's view of long-term oil and natural gas prices. Such a review could result in a charge for impairment which could have a significant effect on the Group's results of operations in the period in which it occurs.

FORWARD LOOKING STATEMENTS

In order to utilize the 'Safe Harbor' provisions of the United States Private Securities Litigation Reform Act of 1995, BP is providing the following cautionary statement. This document contains certain forward-looking statements with respect to the financial condition, results of operations and business of BP and certain of the plans and objectives of BP with respect to these items. These statements may generally, but not always, be identified by the use of words such as 'will', 'expects', 'is expected to', 'may', 'should', 'is likely to', 'intends', 'believes' or similar expressions. In particular, among other statements, (i) certain statements in Item 4 -- Information on the Company and Item 5 -- Operating and Financial Review and Prospects with regard to management aims and objectives, planned expansion, investment or other projects, expected or targeted production volume, capacity or rate, the date or period in which production is scheduled or expected to come on stream or a project or action is scheduled or expected to be completed, (ii) the statements in Item 4 -- Information on the Company -- Strategy and Financial Targets with respect to the Group's ratio of net debt to net debt plus equity, dividend policy, the manner in which we use cash surpluses, the target to reduce the cost structure of the Group, hydrocarbon production growth, targeted performance improvements and effect on pre-tax results, and levels of annual investment, and (iii) the statements in Item 5 -- Operating and Financial Review and Prospects including the statements under 'Outlook' with regard to trends in the trading environment, oil and gas prices, refining, marketing and chemicals margins, inventory and product inventory levels, supply capacity, profitability, results of operation, liquidity or financial position are all forward-looking in nature. By their nature, forward-looking statements involve risk and uncertainty because they relate to events and depend on circumstances that will occur in the future and are outside the control of BP. Actual results may differ materially from those expressed in such statements, depending on a variety of factors, including the specific factors identified in the discussions accompanying such forward-looking statements; future levels of industry product supply, demand and pricing; political stability and economic growth in relevant areas of the world; development and use of new technology and successful partnering; the actions of competitors; natural disasters and other changes to business conditions; wars and acts of terrorism or sabotage; and other factors discussed elsewhere in this report. In addition to factors set forth elsewhere in this report, the factors set forth above are important factors, although not exhaustive, that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

STATEMENTS REGARDING COMPETITIVE POSITION

Statements made in Item 4 -- Information on the Company, referring to BP's competitive position are based on the Company's belief, and in some cases rely on a range of sources, including investment analysts' reports, independent market studies and BP's internal assessments of market share based on publicly available information about the financial results and performance of market participants.

ITEM 4 -- INFORMATION ON THE COMPANY

GENERAL

Unless otherwise indicated, information in this Item reflects 100% of the assets and operations of the Company and its subsidiaries which were consolidated at the date or for the periods indicated, without the exclusion of minority interests. Also, unless otherwise indicated, figures for business turnover include sales between BP businesses.

BP was created on December 31, 1998 by the merger of Amoco Corporation of the USA and The British Petroleum Company p.l.c. of the UK. Following this merger, Amoco Corporation became a wholly owned subsidiary of The British Petroleum Company p.l.c. and was renamed BP Amoco Corporation, and The British Petroleum Company p.l.c. was renamed BP Amoco p.l.c. Amoco Corporation was incorporated in Indiana, USA, in 1889 and The British Petroleum Company p.l.c. was incorporated in England in 1909. On April 14, 2000 we acquired the Atlantic Richfield Company (ARCO) and on July 7, 2000, we completed our successful tender offer for Burmah Castrol plc of England. To signify the single entity that has successfully been created through these combinations, the name of the company was changed to BP p.l.c. with effect from May 1, 2001.

BP is one of the world's leading oil companies on the basis of market capitalization and proved reserves. Our worldwide headquarters is located in London, UK. Our registered address is:

BP p.l.c.
Britannic House
1 Finsbury Circus
London EC2M 7BA
United Kingdom

Tel: +44(0)20 7496 4000

Internet address: www.bp.com

Business Overview

Our main businesses are Exploration and Production, Gas and Power, Refining and Marketing, and Chemicals. Exploration and Production's activities include oil and natural gas exploration and field development and production (upstream activities), together with pipeline transportation and natural gas processing (midstream activities). Gas and Power activities include marketing and trading of natural gas, liquefied natural gas (LNG), natural gas liquids (NGL) and power, the development of international opportunities that monetize gas resources and involvement in select power projects. The activities of Refining and Marketing include oil supply and trading as well as refining and marketing (downstream activities). Chemicals activities include petrochemicals manufacturing and marketing. In addition, we have a solar energy business which is one of the world's largest manufacturers of photovoltaic modules and systems. The Group provides high quality technological support for all its businesses through its research and engineering activities.

We have well established operations in Europe, the USA, Canada, South America, Australasia and parts of Africa. More than 70% of the Group's capital is invested in Organization for Economic Cooperation and Development (OECD) countries with just under one half of our fixed assets located in the USA, and just under one third located in the UK and the Rest of Europe.

We believe that BP has a strong portfolio of assets in each of its four main businesses:

-- In Exploration and Production we have substantial upstream interests in the USA, with onshore natural gas production, oil and natural gas production in the Gulf of Mexico and oil production in Alaska; the UK where we are the largest producer of both oil and natural gas; Norway, Canada, South America, Africa, the Middle East and Asia. We also have significant midstream activities in support of these interests.

-- In Gas and Power, which has been reported as a separate business since January 1, 2000, we have established and growing marketing and trading businesses in North America (USA and Canada), the UK and Europe. Our marketing and trading activities include natural gas, LNG, NGL and power. Our international gas monetization activities are focused on growing gas markets including the USA, Canada, Spain and many of the emerging markets of the Asia Pacific region, notably China. We are involved in power projects in the USA, UK and Spain. Effective January 1, 2001, BP's North American NGL business was transferred from Refining and Marketing to Gas and Power. On January 1, 2002, the solar, renewables and alternative fuels activities were transferred to the Gas and Power business from Other Businesses and Corporate.

-- In Refining and Marketing we have a strong presence in the USA. We market under the Amoco and BP brands in the Midwest, East, and Southeast, and under the ARCO brand on the West Coast. In Europe we have a strong retail position and increased our presence in 2000 by buying out ExxonMobil's interest in the BP/Mobil European fuels business. In 2000, we purchased Burmah Castrol, which significantly increased our lubricants activities throughout the world. In addition we have established or are growing businesses elsewhere in the world under the BP brand.

-- In Chemicals we have a strong manufacturing and marketing base in the USA and Europe, and are aiming to grow in the Asia Pacific region where we already have interests in a number of production facilities. We have a strong position in the technology and production of olefins and derivative products (polyethylene, acetic acid and acrylonitrile), a leading position in aromatics and derivative products (purified terephthalic acid, paraxylene and metaxylene) and have strengthened our polymers market position during 2001 through our deal with Solvay.

On April 13, 2000 BP and ARCO announced that they had received clearance from the US Federal Trade Commission (FTC) for the combination of the two companies and the combination was completed on April 18, 2000. The combination has been accounted for as an acquisition under UK GAAP and as a purchase under US GAAP. The results of ARCO have been included with effect from April 14, 2000, the day following the approval by the US Federal Trade Commission of the acquisition. ARCO stockholders received for each share of ARCO common stock held as of April 17, 2000, 9.84 BP ordinary shares. Such shares were delivered in the form of BP ADSs, or at the election of the holder of ARCO common stock, BP ordinary shares.

On March 15, 2000 ARCO entered into an agreement to sell its Alaskan businesses to Phillips Petroleum Company (Phillips) for approximately $6.5 billion cash subject to purchase price adjustments (and up to an additional $500 million based on the prices realized on production subsequent to December 31, 1999). Under the agreement ARCO agreed to sell all of the outstanding shares of ARCO Alaska Inc., together with certain other subsidiaries of ARCO engaged principally in the operation of ARCO's Alaskan businesses, along with certain pipeline and marine assets associated with the transport of Alaskan crude oil. The major portion of the sale closed on April 26, 2000.

BP acquired Burmah Castrol of the UK on July 7, 2000 for $4.8 billion through a cash offer to shareholders of (pound)16.75 per share. The public share price on the date of announcement, March 10, 2000, was (pound)9.65. Burmah Castrol is a global marketer of specialized lubricant and chemical products and services. Burmah Castrol had operations in over 50 countries and employed some 18,000 people.

In December 1999, we agreed with ExxonMobil on the principles under which the BP/Mobil European joint venture would be dissolved in response to the conditions of the European Commission's authorization of the Exxon and Mobil merger. Under the agreement BP purchased ExxonMobil's 30% interest in the fuels business for $1.5 billion with effect from August 1, 2000. In addition, the two companies divided the assets of the lubricants business broadly in line with their equity stakes (Mobil 51%, BP 49%). This dissolution was substantially completed in 2000, thus increasing BP's share of all European markets where the fuels joint venture was active.

On September 15, 2000 we acquired through ARCO the common stock of Vastar held by minority shareholders at a price of $83 per share for a total consideration of $1.6 billion. The public share price on the date of announcement, March 16, 2000, was $71 7/16. Vastar became a wholly owned subsidiary of the Company.

During 2000 BP made two strategic investments in China, one of the world's fastest growing economies. BP invested $416 million in the China Petroleum and Chemical Corporation (Sinopec) and $578 million in PetroChina in the initial public offerings of both companies. BP has a 2.2% interest in each company. Separately, BP announced plans to form joint ventures with both companies: in natural gas marketing and fuels retailing with PetroChina and in fuels and petroleum products marketing and chemicals with Sinopec. PetroChina and Sinopec are two of China's major companies in the oil and chemicals businesses.

Following completion of the merger between BP and Amoco on December 31, 1998 and in the context of low oil prices at the time, BP undertook a strategic and portfolio review in early 1999. This was completed in the Spring of 1999 and resulted, among other things, in the development of an asset divestment programme. The guiding principle of the strategic and portfolio review was to concentrate the combined Group's operations on areas of competitive strength and, in the upstream portfolio, to dispose of assets which would not be robustly economic on the basis of conservative assumptions about future oil and natural gas prices. Divestitures under this programme continued in 2000, and the programme was completed in 2001.

Strategy and Financial Targets

In Exploration and Production our goal is to have significant shares of the larger oil and natural gas fields where our supply costs can be fully competitive with all other producers. The Gas and Power business is specifically designed to extend our interests as the mix of world energy consumption shifts in favour of natural gas. In Refining and Marketing we intend to invest in geographic markets which are growing and in convenience retailing, while focusing our refining on advantaged areas. In Chemicals we focus on excellence in manufacturing and close links to both the supply of resources and actual and potential demand growth.

As part of this strategy we developed a financial framework to maintain a ratio of net debt to net debt plus equity, after adjusting equity for the fixed asset revaluation adjustment and goodwill consequent upon the ARCO and Burmah Castrol acquisitions, of around 20-30% and a dividend policy with the aim of returning to shareholders around 50% of our replacement cost profit before exceptional items and after adjusting for special items and acquisition amortization, adjusted to mid-cycle operating conditions. Special items are non-recurring charges and credits that are not classified as exceptional items under UK GAAP. Acquisition amortization refers to depreciation relating to the fixed asset revaluation adjustment and amortization of goodwill consequent upon the ARCO and Burmah Castrol acquisitions. Mid-cycle operating conditions reflect not only adjustments to hydrocarbon prices and margins, but also costs and capacity utilization, to levels which we would expect on average over the long term. If circumstances give us a larger surplus of cash than is required to fund our capital programme and meet operational needs, the surplus may be used to pay down debt to a level at the lower end of our gearing range and/or be returned to shareholders.

In January 2002 BP adopted a new UK Financial Reporting Standard No. 19 'Deferred Tax' (FRS 19). This standard requires deferred tax to be accounted for on a full rather than a partial provision basis. Prior years will be restated. The new standard will increase the effective tax rate and reduce profit and shareholders' interest. For example, if this new standard had been applied to the reported results for 2001, the tax charge for the year would have increased by $1,358 million to $6,375 million, and at December 31, 2001 there would have been a reduction of $9,050 million in shareholders' interest. It will have no effect on cash flow. In order to maintain the substance of the existing financial framework, we are restating BP's target band of net debt to net debt plus equity, after adjusting equity for the fixed asset revaluation adjustment and goodwill consequent upon the ARCO and Burmah Castrol acquisitions, from around 20-30% to around 25-35% and our target dividend payout ratio from around 50% to around 60% of our replacement cost profit before exceptional items and after adjusting for special items and acquisition amortization, adjusted to mid-cycle operating conditions.

Following completion of the ARCO and Burmah Castrol acquisitions in 2000 we announced our 2001 targets which reflected the enlarged Group. Our cost reduction target was to reduce the combined cost structure of the enlarged Group by $5.8 billion by the end of 2001. Cost reductions also included the effect of disposals on cash costs and lower exploration write-offs. Certain cash costs in 2000 and 2001 were adjusted to reflect cost levels which we would expect on average over the long term. Total cost reductions achieved by the end of 2001 were $6.1 billion.

In February 2001, we announced further specific targets for 2001. We targeted underlying performance improvements, which include cost savings and volume growth, aiming to increase pre-tax results under mid-cycle operating conditions, adjusted for acquisition amortization and special items, by $2.0 billion in 2001; growth in hydrocarbon production of 5.5%; and annual investment, excluding acquisitions, in the $12-13 billion range. This level of expenditure was intended to permit growth investment in Exploration and Production to enable the business to achieve targeted production growth of 5.5% each year in the medium term. This amount of investment is consistent with historic levels for the enlarged Group.

We achieved underlying performance improvements of $2.0 billion and production growth of 5.5% in 2001. Investment, excluding acquisitions, in 2001 was $13.2 billion and total investment was $14.1 billion.

We achieved the original 1999-2001 target of $10 billion proceeds from disposals by end-2001. This excluded the FTC-mandated divestment of ARCO's Alaskan interests and certain other assets.

In February 2002, we confirmed that our targets going forward remain unchanged. Specifically, we aim to achieve pre-tax underlying performance improvements, under mid-cycle operating conditions, of $1.4 billion through cost savings and volume growth in 2002 and annual hydrocarbon production growth of 5.5% in the medium term. We continue to plan for annual investment, excluding acquisitions, in the $12-13 billion range.

The targets disclosed above for 2002 and beyond are forward looking statements and as such are subject to numerous risks and uncertainties which may cause actual results to differ as described under Item 3 -- Risk Factors and Item 3 -- Forward Looking Statements.

Financial and Operating Information

The following table summarizes the Group's turnover, results and capital expenditure for the last five years and total assets at the end of each of those years.

	2001	2000	1999	1998	1997
	Years ended December 31, ($ million)				
Turnover..............................	175,389	161,826	101,180	83,732	108,564
Less: joint ventures..................	1,171	13,764	17,614	15,428	16,804
Group turnover (sales to third parties)	174,218	148,062	83,566	68,304	91,760
Total replacement cost operating profit	16,135	17,756	8,894	6,521	10,683
Profit for the year*..................	8,010	11,870	5,008	3,220	5,673
Capital expenditure and acquisitions...	14,124	47,613(a)	7,345(b)	10,362	11,420
Total assets..........................	141,158	143,938	89,561	84,915	86,279

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* After minority shareholders' interest

(a) Capital expenditure and acquisitions for 2000 includes $27,506 million for the acquisition of ARCO and $8,936 million for acquisitions for cash, the details of which can be found in Item 5 -- Operating and Financial Review and Prospects -- Group Results.

(b) Capital expenditure and acquisitions in 1999 reflected reduced investment following the merger of BP and Amoco.

All capital expenditure and acquisitions have been financed from cash flow from operations, disposal proceeds and external financing.

Information for 2001, 2000 and 1999 concerning the profits and assets attributable to the businesses and to the geographical areas in which the Group operates is set forth in Item 18 -- Financial Statements -- Note 44.

The following table shows our production for the last five years and the estimated proved oil and natural gas reserves at the end of each of those years.

	2001	2000	1999	1998	1997
	Years ended December 31,				
Total crude oil production (thousand barrels per day) (a)..........	1,931	1,928	2,061	2,049	1,930
Total natural gas production (million cubic feet per day) (a)................	8,632	7,609	6,067	5,808	5,858
Total estimated net proved crude oil reserves (million barrels) (b)..........	7,217	6,508	6,535	7,304	7,612
Total estimated net proved natural gas reserves (billion cubic feet) (b).......	42,959	41,100	33,802	31,001	30,374

(a) Includes BP's share of equity-accounted entities.

(b) Net proved reserves of crude oil and natural gas exclude production royalties due to others and reserves of equity-accounted entities.

During 2001, 2,164 million barrels of oil and natural gas, on an oil equivalent* basis (mmboe), were added to BP's proved reserves (excluding purchases, sales and equity-accounted entities), replacing 191% of the volume produced. After allowing for production, which amounted to 1,133 mmboe, BP's proved reserves increased to 14,624 mmboe. These proved reserves are mainly located in the USA (42%), Trinidad and Tobago (16%) and the UK (14%).

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* Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

14

Recent developments

With effect from February 1, 2002, BP acquired a majority stake in Veba Oil from E.ON. Veba Oil owns Aral, Germany's biggest fuels retailer. BP paid E.ON $1.63 billion in cash and assumed some $0.85 billion of debt in return for 51% and operational control of Veba Oil. Additionally, E.ON can require BP to buy the remaining 49% of Veba Oil for $2.40 billion in cash from April 1, 2002 under the terms of an agreement between the two companies announced in July 2001.

That agreement envisaged part of the payment for Veba Oil being met by the sale to E.ON of BP's wholly-owned subsidiary, Gelsenberg, which holds a 25.5% stake in Germany's largest natural gas distributor, Ruhrgas. Although that sale was prohibited by Germany's Federal Cartel Office, the decision is being appealed to the German Economics Ministry, which is expected to rule in mid-2002. If the German Economics Ministry were to approve the Ruhrgas transaction, BP would sell its Ruhrgas stake to E.ON for an agreed $2.10 billion.

As a condition of regulatory approval of the deal BP is required to dispose of 4% of the combined 26.5% retail market share of BP and Aral in Germany, 45% of its stake in the Bayernoil refinery, two of its three shareholdings in the ARG ethylene pipeline, and to make it possible for a new entrant to supply aviation fuel on competitive terms at Frankfurt airport.

Separately BP and E.ON announced that they had agreed, subject to various regulatory and other consents, to sell Veba's oil and natural gas exploration and production business to Petro-Canada for $2.00 billion. From this sale BP would receive $1.65 billion and E.ON the balance.

15

SEGMENTAL INFORMATION

The following tables show turnover and replacement cost profit by business and by geographical area, for the years ended December 31, 2001, 2000, and 1999.

	Years ended December 31,	
Turnover (a)	2001	2000 (b)

	Total sales	Sales between businesses	Sales to third parties	Total sales	Sales between businesses	Sales to third parties	
					($ million)		
By business							
Exploration and Production......	28,229	19,660	8,569	30,942	16,787	14,155	1
Gas and Power..................	39,208	2,954	36,254	21,013	346	20,667	
Refining and Marketing..........	120,233	2,903	117,330	107,883	5,923	101,960	6
Chemicals......................	11,515	233	11,282	11,247	216	11,031	
Other businesses and corporate..	783	--	783	249	--	249	
Group turnover.................	199,968	25,750	174,218	171,334	23,272	148,062	9
Share of joint venture sales....			1,171			13,764	
			175,389			161,826	

	Total sales	Sales between areas	Sales to third parties	Total sales	Sales between areas	Sales to third parties	
					($ million)		
By geographical area							
UK (c)......................	47,618	13,467	34,151	45,400	10,970	34,430	3
Rest of Europe..............	36,701	7,603	29,098	20,553	1,911	18,642	
USA.........................	84,696	939	83,757	71,084	829	70,255	3
Rest of World...............	33,911	6,699	27,212	31,014	6,279	24,735	1
	202,926	28,708	174,218	168,051	19,989	148,062	9
Share of joint venture sales							
UK..........................			13			3,314	
Rest of Europe..............			30			12,316	
USA.........................			318			270	
Rest of World...............			810			686	
			1,171			16,586	
Sales between areas			--			2,822	
			1,171			13,764	

(a) Turnover to third parties is stated by origin which is not materially different from turnover by destination. Transfers between Group companies are made at market prices taking into account the volumes involved.

(b) 1999 and 2000 have been restated to reflect the transfer of the NGL business in North America from Refining and Marketing to Gas and Power.

(c) UK area includes the UK-based international activities of Refining and Marketing.

Analysis of replacement cost profit	Group replacement cost operating profit (a)	Joint ventures	Associated undertakings	Total replacement cost operating profit (a)	Ex
			($ million)		
Year ended December 31, 2001					
By business					
Exploration and Production..........	11,858	373	186	12,417	
Gas and Power......................	337	--	184	521	
Refining and Marketing.............	3,347	83	195	3,625	
Chemicals..........................	21	(13)	120	128	
Other businesses and corporate......	(631)	--	75	(556)	
	14,932	443	760	16,135	
By geographical area					
UK (c)............................	2,657	(3)	14	2,668	
Rest of Europe.....................	1,579	(1)	236	1,814	
USA................................	6,740	76	233	7,049	
Rest of World......................	3,956	371	277	4,604	
	14,932	443	760	16,135	
Year ended December 31, 2000 (d)					
By business					
Exploration and Production..........	13,399	384	229	14,012	
Gas and Power......................	409	--	162	571	
Refining and Marketing.............	2,924	433	166	3,523	
Chemicals..........................	576	(9)	193	760	
Other businesses and corporate......	(1,152)	--	42	(1,110)	
	16,156	808	792	17,756	
By geographical area					
UK (c)............................	3,629	106	38	3,773	
Rest of Europe.....................	1,488	264	261	2,013	
USA................................	7,006	44	246	7,296	
Rest of World......................	4,033	394	247	4,674	
	16,156	808	792	17,756	
Year ended December 31, 1999 (d)					
By business					
Exploration and Production..........	6,686	175	122	6,983	
Gas and Power......................	258	--	179	437	
Refining and Marketing.............	1,111	380	123	1,614	
Chemicals..........................	561	--	125	686	
Other businesses and corporate......	(880)	--	54	(826)	
	7,736	555	603	8,894	
By geographical area					
UK (c)............................	2,063	(1)	49	2,111	

Rest of Europe.....................	548	381	238	1,167
USA................................	2,803	13	185	3,001
Rest of World......................	2,322	162	131	2,615
	7,736	555	603	8,894

(a) Replacement cost operating profit is before inventory holding gains and losses and interest expense, which is attributable to the corporate function. Transfers between Group companies are made at market prices taking into account the volumes involved.

(b) Exceptional items comprise profit or loss on the sale of fixed assets and businesses or termination of operations and in addition for 1999 include fundamental restructuring costs.

(c) UK area includes the UK-based international activities of Refining and Marketing.

(d) 1999 and 2000 have been restated to reflect the transfer of the NGL business in North America from Refining and Marketing to Gas and Power.

17

EXPLORATION AND PRODUCTION

The activities of our Exploration and Production business include oil, natural gas exploration and field development and production - the upstream activities - as well as the management of crude oil and natural gas pipelines, processing and export terminals and liquefied natural gas (LNG) processing facilities - the midstream activities. We have Exploration and Production interests in 28 countries. Areas of activity include the USA, UK, Norway, Canada, South America, Africa, the Middle East, and Asia. Production during 2001 came from 23 countries. Our most significant midstream activities are in three major pipelines - the Trans Alaska Pipeline System (BP 46.9%), the Forties Pipeline System (BP 100%) and the Central Area Transmission System pipeline (BP 29.5%) both in the UK sector of the North Sea - and three major LNG plants - the Atlantic LNG plant in Trinidad (BP 34%), in Indonesia through the joint venture operating company Virginia Indonesia Co. (VICO) (BP 50%) and in Australia through our share of LNG from the North West Shelf natural gas development (BP 16.7%).

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Turnover (a)..	28,229	30,942	19,133
Total replacement cost operating profit.................	12,417	14,012	6,983
Total assets..	69,572	65,904	44,967
Capital expenditure and acquisitions....................	8,861	6,383	4,194
	($ per barrel)		
Average BP oil realizations............................	22.50	26.63	16.74

Average West Texas Intermediate oil price................	25.89	30.38	19.33
Average Brent oil price.................................	24.44	28.44	17.94
	($ per thousand cubic feet)		
Average BP natural gas realizations......................	3.30	2.91	1.92
Average BP US natural gas realizations...................	3.99	3.72	2.06
Average Henry Hub gas price (b)..........................	4.26	3.90	2.27

(a) Excludes BP's share of joint venture turnover of $666 million in 2001, $585 million in 2000, and $497 million in 1999.

(b) Henry Hub First of Month Index.

Strategy and Overview

Our strategy remains unchanged, targeting profitable production growth of 5.5% per year, underpinned by the following strategic elements: to have a leading position in high quality basins around the world; to be a low-cost supplier of oil, competitive with OPEC producers; and to supply low-cost gas to markets. Evidence of 2001 delivery included capturing the remaining $500 million of $3.1 billion of synergy cost savings from the merger of BP and Amoco and the acquisition of ARCO, and achieving our production growth target of 5.5%. In the future, we intend that our strategy will continue to be underpinned by three key areas of focus: sustaining and maximizing the value of our base portfolio, exploring for and developing resources in existing and emerging basins, and upgrading the quality of our portfolio.

The first element underpinning our Exploration and Production strategy is to maximize the value of our base portfolio by optimising production volumes and driving efficiencies. We seek opportunities that are sustainable in the context of fluctuating oil and natural gas prices.

We optimise production volumes through decline management and enhanced recovery technologies to mitigate volume decline and increase ultimate recoveries in mature fields. For example, during 2001:

-- We made extensive use of time-lapse 3-D seismic technology to transform our in-field drilling programme. 21 operated fields are now covered worldwide. In the North Sea, our increased reservoir understanding led to additional production of 15 mboe/d compared to 2000 and should enable access to additional reserves in the region.

-- We continued to advance the technology associated with multi-lateral wells and achieved an industry first on the Harding field with the installation of sand control screens in such a well.

-- We successfully used the world's first commercial expandable liner hanger in a producing well in the US Lower 48 States. This technology should reduce drilling times and potentially reduce safety risks on deep wells.

-- We advanced the use of cost efficient Coil Tubing Drilling to drill multi-lateral wells, creating more economical access to the development of Alaska's viscous oil.

-- We developed a technique in the North Sea that helps to identify bottlenecks or constraints throughout the production system. During 2001 we began deploying this technique throughout our upstream business. For example, in Azerbaijan we increased operating efficiency by 2%.

Since 1998, our unit production costs (often referred to as unit lifting costs) have decreased by 16%. We have driven operating efficiencies by:

-- Leveraging the economies of scale achieved through business combinations and acquisitions.

-- Benchmarking, internally and externally, and sharing best practices across the business units.

-- Working with key suppliers, contractors and partners.

The second element underpinning our strategy is to explore for and develop resources in emerging basins, as well as in existing basins on a selective basis, to provide growth for the future. We do this through focused large projects and selective development of smaller satellite projects to take advantage of existing infrastructure.

-- We are the largest leaseholder in the Gulf of Mexico and have interests in nine of the ten largest Gulf of Mexico developments (BP operates six). Our deepwater position in conjunction with integrated development programmes should allow delivery of both near-term and long-term production growth. In 2001, we announced the discovery at Blind Faith (BP 77.5% and operator) and saw the start up of the BP operated Nile Field (in addition to the non-BP operated Mica and Crosby Fields). We also approved investment capital for three of the four newest BP operated major field developments and began fabrication activities. In 2002 we expect to begin production from King, King's Peak, Princess (Phase I) and Horn Mountain fields. During 2003 to 2006, we expect to begin production at our NaKika, Princess (Phase II), Thunder Horse (formerly known as Crazy Horse), Holstein, Mad Dog and Atlantis fields. Production from these fields should contribute substantially to our growth.

-- In Angola, we were involved in four new oil discoveries as well as the Girassol project which went into production in December 2001. We also sanctioned the Kizomba A and Jasmim developments.

-- In Trinidad, we approved construction of the world's largest methanol plant and commenced expansion of the existing LNG plant by an additional two trains. Trains are facilities for compressing, liquefying, storing and offloading natural gas. BP will supply 50% of the natural gas for the second train and 75% for the third train, which we expect to come onstream in 2002 and 2003 respectively.

-- In Vietnam, we announced the construction of the $1.3-billion Nam Con Son offshore natural gas project. The project is expected to develop significant offshore natural gas for use by three generating plants to provide electricity to Vietnam.

The third element underpinning our strategy is to upgrade the quality of our asset portfolio by focusing investments in core areas (where we have either critical mass and/or significant competitive position), selectively investing in growth, and disposing of non-strategic assets. We have a rigorous process for evaluating the economic merit and strategic fit of investment opportunities. For example, prior to sanctioning, we test new projects in an effort to ensure that they achieve a return in excess of the cost of capital at bottom of cycle prices (that is $11 Brent).

In support of continued growth, 2001 capital expenditure, at $8.9 billion (including $0.3 billion of acquisitions), was $2.5 billion higher than in 2000 ($6.4 billion).

Examples of our investment and divestment activity include:

-- In June 2001, we entered into an agreement to dispose of our 9.5% stake in the Kashagan discovery in Kazakhstan, after determining that it did not enhance our competitive position.

-- We acquired a further 9.7% stake in the Tangguh LNG project in Indonesia. This acquisition increased our share of Tangguh to about 50%. Tangguh is expected to be a long-term competitive supply source helping to meet rising demand in the region.

-- In December 2001, we announced that the assets of Chernogorneft had been returned to Sidanco (BP 11.2%). This completes the restructuring of Sidanco with its debt substantially repaid and non-core assets disposed of.

-- In January 2002, we acquired Statoil's interest in the Nam Con Son gas project. This acquisition increased our interest in Block 06.1 from 26.6% to 35%. Our interest in Block 05.2 increased from 35% to 100%.

Upstream Activities

Exploration

The Group explores for oil and natural gas under a wide range of licensing, joint venture and other contractual agreements. We may do this alone or, more frequently, with partners. BP acts as operator for many of these ventures.

Our exploration and appraisal costs in 2001 were $1,102 million compared to $1,295 million in 2000. About 65% of 2001 exploration and appraisal capital was directed towards appraisal activity as we delineated the significant discoveries made during 1999 and 2000. In 2001, we participated in 120 gross (48.4 net) exploration and appraisal wells in 21 countries. The principal areas of activity were Angola, Australia, Canada, Egypt, Norway, Trinidad, UK and the USA.

In 2001, we obtained upstream rights in several new tracts which are expected to provide a foundation for continued exploration success. These include the following:

-- In Egypt, we acquired a 16.67% interest in the West Med Block in the Nile delta. We also increased our working interest in the Nile Delta North Alex concession from 50% to 60%.

-- In the US Central Gulf of Mexico Lease Sale 178, we achieved a 74% success rate. We were successful in obtaining 6 new deepwater blocks including the primary block in a highly competitive prospect. Four of these deepwater blocks were near existing discoveries. We also achieved an 88% success rate in the Gulf of Mexico Shelf 178 licensing round. In addition, we submitted and won bids for two blocks on the

Shelf in the Western Gulf of Mexico 180 Lease Sale.

-- In the UK, we were awarded operatorship and 66.67% working interest in North Sea Block 204/18, the only block on which we bid in the UKCS 19th Licensing Round.

In 2001, we were involved in discoveries in Angola, Argentina, Australia, Egypt, Pakistan, Trinidad, and the USA. In most cases, reserve bookings from these fields will depend on the results of ongoing technical and commercial evaluations, including appraisal drilling. Our 2001 discoveries included the following:

-- In the deepwater US Gulf of Mexico we announced a new discovery at Blind Faith (BP 77.5%), which is approximately 20 miles northeast of the Thunder Horse development, discovered in 1999.

-- Also in the deepwater US Gulf of Mexico, we announced the Aspen discovery (BP 80% and operator). In early 2002, we announced that Aspen would be 'fast tracked' to production and we reduced our interest to 40%.

-- In Trinidad, we made another significant natural gas discovery in the Cashima well (BP 100%).

-- In Angola, we were involved in three new oil discoveries: Violeta in Block 17 (BP 16.7%), and Mavacola and Vicango in Block 15 (BP 26.7%).

-- In Australia, we participated in the Io natural gas discovery on the Northwest Shelf (BP 13%).

-- In Egypt's Nile Delta we made two natural gas discoveries, Fayoum (BP 60% and operator) and Libra (BP 60% and operator).

-- In Argentina, our joint venture, Pan American Energy (BP 60%), established Tres Picos as a major natural gas discovery (BP 60%).

Reserves and Production

We annually review our total reserves of crude oil, condensate, natural gas liquids and natural gas to take account of production, field reassessments, the application of improved recovery techniques, the addition of new reserves from discoveries and economic factors. We also conduct selective periodic reserve reviews for individual fields.

Details of our net proved reserves of crude oil, condensate, natural gas liquids and natural gas at December 31, 2001, 2000, and 1999 and reserves changes for each of the three years then ended are set out in the Supplementary Oil and Gas Information section in Item 18 -- Financial Statements.

Total hydrocarbon proved reserves, on an oil equivalent basis and excluding equity-accounted entities, comprised 14,624 million barrels of oil equivalent (mmboe) at December 31, 2001, an increase of 8% versus December 31, 2000. Natural gas represents about 51% of these reserves. Reserve replacement through extensions, discoveries, revisions and improved recovery exceeded production for the eighth consecutive year with a ratio of 191%.

In 2001, total additions to the Group's proved reserves (excluding purchases and sales and equity-accounted entities) amounted to 2,164 mmboe, mostly through extensions to existing fields and discoveries of new fields. The principal reserve additions were in Algeria, Angola, Azerbaijan, US Gulf of Mexico, UK and Trinidad, following development approval of the rest of the In Salah project, together with Kizomba A, Azeri-Chirag-Gunashli Phase 1, Thunder Horse and Clair fields and the sanctioning of the Atlas Methanol plant.

Our total hydrocarbon production (including equity-accounted entities) during 2001 averaged 3,419 thousand barrels of oil equivalent per day (mboe/d), an increase of 179 mboe/d, or 5.5% compared with 2000, as production declines in mature fields were more than offset by production start-ups and build-ups to full production. About 40% of our production was in the USA and 23% in the UK.

21

The following tables show BP's production by major field for the three years 1999 to 2001, and BP's aggregate estimated net proved reserves as at December 31, 2001:

Crude oil (a)

			Net production		
Production	Field or Area	Interest	2001	2000	1999
		(%)	(thousand barrels per da		
Alaska (b)	Prudhoe Bay*	26.3	123	146	202
	Kuparuk	39.2	76	81	90
	Milne Point*	100.0	45	40	42
	Endicott*	67.9	19	21	25
	Point McIntyre	32.2	10	16	25
	Other	Various	15	10	21
Total Alaska			288	314	405
Lower 48 States onshore	Altura(b)	Various	--	36	127
	Other	Various	213	182	133
Total Lower 48 States onshore			213	218	260
Gulf of Mexico (b)	Mars	28.5	42	38	36
	Troika	33.3	25	28	30
	Pompano*	75.0	21	26	29
	Other	Various	155	105	44
Total Gulf of Mexico			243	197	139
Total USA			744	729	804
UK offshore (b)	ETAP+	Various	80	85	80
	Foinaven*	72.0	60	64	56
	Forties*	96.1	51	53	66
	Harding*	70.0	42	57	58

	Schiehallion/Loyal*	Various	40	44	36
	Magnus*	85.0	37	47	48
	Andrew*	62.8	25	33	43
	Miller*	40.0	15	22	30
	Other	Various	99	89	123
Total UK offshore			449	494	540
Onshore	Wytch Farm*	50.5	36	40	40
Total UK			485	534	580
Norway	Draugen	18.4	40	38	37
	Valhall*	28.1	22	23	27
	Ula*	80.0	18	16	20
	Gyda*	56.0	12	12	14
Netherlands and other Norway	Various	Various	8	1	2
Total Rest of Europe			100	90	100

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* BP operated.

\+ BP operates the majority of the fields in this area.

Production	Field or Area	Interest	Net production 2001	2000	1999
		(%)	(thousand barrels per da		
Australia	Various	16.7	40	37	23
Azerbaijan	Azeri-Chirag-Gunashli*	34.1	35	30	32
Canada (b)	Various	Various	18	19	56
Colombia	Cusiana/Cupiagua*	19.0	48	52	66
Egypt	October	30.4	22	30	35
	Other	Various	69	78	95
Trinidad	Various	100.0	48	47	49
Venezuela	Various	Various	54	46	30
Other (b)	Various	Various	60	51	21
Total Rest of World			394	390	407
Total Group			1,723	1,743	1,891
Equity-accounted entities					
Abu Dhabi (d)	Various	Various	126	127	113
Argentina	Various	Various	50	40	41
Other	Various	Various	32	18	16
Total equity-accounted entities			208	185	170
Total Group and BP share of equity-accounted entities (e)			1,931	1,928	2,061

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*   BP operated.
\+   BP operates the majority of the fields in this area.

	December 31, 2001				
Estimated net proved reserves (a)	UK	Rest of Europe	USA	Rest of World	Total
	(millions of barrels)				
Subsidiary undertakings					
Developed................	1,008	269	2,195	836	4,308
Undeveloped..............	317	112	1,394	1,086	2,909
	1,325	381	3,589	1,922	7,217
Equity-accounted entities					1,159
Total Group and BP share of equity-accounted entities					8,376

Natural gas (a)(c)

Production	Field or Area	Interest	Net production 2001	2000	1999
		(%)	(million cubic feet per d		
Lower 48 States onshore (b)	San Juan Coal*	Various	615	563	427
	Arkoma+	Various	219	94	111
	San Juan Conventional+	Various	217	185	129
	Tuscaloosa+	Various	187	171	175
	Hugoton+	Various	180	170	162
	Jonah*	79.1	109	77	57
	Wamsutter*	70.5	100	100	92
	Whitney Canyon+	Various	50	47	52
	Anschutz Ranch East*	Various	45	55	67
	Moxa Arch*	41.0	43	52	77
	Altura	Various	--	34	118
	Other	Various	595	613	227
Total Lower 48 States onshore			2,360	2,161	1,694
Alaska	Various	Various	11	9	10
Gulf of Mexico (b)	Marlin*	100.0	79	3	--
	Matagorda Island 623*	44.0	76	78	99
	Ram Powell (VK 912)	31.0	58	60	72
	Matagorda Island 519*	82.0	40	56	39

	Other	Various	930	687	361
Total USA			3,554	3,054	2,275
UK offshore (b)	Bruce*	37.0	256	201	175
	Marnock*	62.0	125	148	79
	Braes	Various	100	99	76
	West Sole*	100.0	81	89	97
	Armada	18.2	71	75	77
	Amethyst*	59.5	68	56	42
	Ravenspurn South*	100.0	66	77	87
	Britannia	9.0	65	41	--
	East Leman*	48.4	59	58	42
	Viking Complex	50.0	54	81	107
	Vulcan	50.0	33	44	26
	Other	Various	730	678	487
Onshore	Various	Various	5	5	6
Total UK			1,713	1,652	1,301
Netherlands	P/18-2*	48.7	47	52	63
	Other	Various	52	43	48
Norway	Various	Various	48	41	53
Total Rest of Europe			147	136	164

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*   BP operated.

\+   BP operates the majority of the fields in this area.

Production	Field or Area	Interest	Net production 2001	2000	1999
		(%)	(million cubic feet per d		
Rest of World					
Australia	Various	16.7	237	205	215
Canada (b)	Kirby*	71.9	72	69	132
	Brazeau River Gas*	70.0	71	63	41
	Ricinus*	70.0	61	52	54
	Marten Hills*	96.0	45	47	56
	Leismer*	54.2	28	32	64
	Other	Various	307	319	342
China	Yacheng*	34.0	108	77	--
Indonesia	Pagerungan*	100.0	242	199	103
	Sanga-Sanga	26.3	164	120	--
	Other*	46.0	95	54	--
Sharjah	Sajaa*	40.0	125	145	168
	Other	Various	35	39	38
Trinidad	Mahogany*	100.0	529	530	367
	Amherstia*	100.0	244	17	--
	Immortelle*	100.0	128	232	207
	Flamboyant*	100.0	52	69	92
	Other*	100.0	58	37	115

Other (b)	Various	Various	272	198	69
Total Rest of World			2,873	2,504	2,063
Total Group			8,287	7,346	5,803
Equity-accounted entities					
Argentina	Various	Various	236	187	145
Other	Various	Various	109	76	119
Total equity-accounted entities			345	263	264
Total Group and BP share of equity-accounted entities			8,632	7,609	6,067

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* BP operated.

\+ BP operates the majority of the fields in this area.

	December 31, 2001				
Estimated net proved reserves (a)	UK	Rest of Europe	USA	Rest of World	Total
	(billions of cubic feet)				
Subsidiary undertakings					
Developed.................	3,212	265	12,232	8,040	23,749
Undeveloped..............	1,160	43	2,535	15,472	19,210
	4,372	308	14,767	23,512	42,959
Equity-accounted entities					3,216
Total Group and BP share of equity-accounted entities					46,175

25

(a) Net proved reserves of crude oil and natural gas, stated as of December 31, 2001, exclude production royalties due to others, and include minority interests in consolidated operations.

(b) In 2001, BP purchased part of the interests of Statoil in Vietnam and the interest of Inaquimicas in Cusiana/Cuipiagua in Colombia.

In 2000, BP acquired the interests of ARCO outside Alaska. At the same time, a deal was concluded (primarily with Exxon and Phillips) in which the oil and natural gas interests in Prudhoe Bay (and some of the associated fields) were realigned. We also disposed of our interest in Altura Energy. In addition to portfolio management in the USA and Canada, we disposed of certain of our interests in Venezuela, Colombia and the UK and acquired an interest in Pakistan as part of the Burmah Castrol acquisition.

In 1999, BP sold certain interests in Canada and Venezuela. At the end of the year we purchased a significant part of Repsol YPF's share of the assets of the dissolved Crescendo Resources partnership, a major natural gas producer and processor in Texas and Oklahoma.

(c) Natural gas production volumes exclude gas consumed in operations.

(d) The BP Group holds proportionate interests, through associated undertakings, in onshore and offshore concessions in Abu Dhabi expiring in 2014 and 2018, respectively.

(e) Includes NGL from processing plants in which an interest is held of 78, 41 and 54 thousand barrels per day for 2001, 2000 and 1999, respectively.

United States

We are the largest producer of both liquids (crude oil and NGLs) and natural gas in the USA.

Our 2001 US liquids and NGL production averaged 744 mb/d (thousand barrels per day), an increase of 2% from 2000. Approximately 39% of our 2001 oil production came from Alaska, 33% from the Gulf of Mexico, and the remainder from onshore Lower 48 States. Our US natural gas production in 2001 was 3,554 mmcf/d (million cubic feet per day), an increase of 16% over 2000.

Development expenditure in the USA (excluding pipelines) during 2001 was $3,723 million, compared with $2,328 million in 2000, an increase of 60%.

Gulf of Mexico

Our largest area of growth in the USA is focused in the deepwater Gulf of Mexico, which builds on our strong and stable US natural gas production base and more than offsets the decline in our current principal oil producing fields in Alaska. In 2001, our deepwater Gulf of Mexico liquids production was up over 23% from 2000 levels, averaging 243 mb/d. Gas production was up over 34% from 2000 levels, averaging 1,183 mmcf/d.

Growth in 2001 was driven by the activity in the major facility hubs in the deepwater Gulf of Mexico and comprised the following:

-- The Marlin hub (BP 80% and operator) reached record production rates exceeding 60 mboe/d, including a peak natural gas rate of 325 mmcf/d. In addition the Nile subsea development (BP 50% and operator) was completed on schedule in 2001. The King and King West subsea developments (BP 100% and operator) are scheduled for tie-in in 2002 and 2003 respectively.

-- The Pompano platform (BP 75% and operator) and subsea development booked 30 mmboe gross reserves in two major prospects: Pompano Subsalt and MC29. Production rates of 30 mmcf/d and 8 mboe/d gross from the subsalt well have exceeded expectations. The Pompano facility was upgraded to increase throughput by 30% in 2001. The Pompano facility improved its baseline run time from under 90% in 2000 to 93% in 2001.

The Mica subsea development (BP 50%) was successfully tied-in to the Pompano facility 60 days ahead of scheduled startup, and on budget. Mica is the longest oil subsea tieback in the Gulf of Mexico to date and production operations are on track.

-- Our active drilling and well work programme was successful at arresting field decline in the Troika field (BP 33% and operator) and we continued our work to optimise production configuration. Gross production in 2001 averaged 108 mboe/d from 6 subsea development wells.

-- Due to the continued successful development drilling results at Mars (BP 29%) and the start-up of the Europa (BP 33.33%) and MC 764 (BP 67%) subsea developments, the Mars field surpassed the 250 mmboe cumulative production milestone. Development drilling continued at Mars Tension Leg Platform in order to maintain a full system at 220 mmcf/d and 200 mboe/d.

-- The Ursa platform (BP 23%) continued to ramp up in 2001 with six new wells drilled and completed -- three Ursa wells and three from the start-up of Crosby, a subsea tieback (BP 50%). Ursa is the largest floating structure currently in the Gulf of Mexico and produced in excess of 92 mb/d of oil and 269 mmcf/d of natural gas on average for the year, achieving the 100 mmboe produced milestone in December 2001. In 2002 we expect to begin production from the Princess field (BP 23%).

-- The 300 mmboe Diana/Hoover (BP 33%) Western Gulf of Mexico basin opening development project began operations in 2000. The development consists of a floating deep-draft Caisson Vessel (DDCV) host located over the Hoover field in 4,500 feet of water. Diana, a five well subsea development, is tied back to the Hoover DDCV. The Hoover DDCV is the deepest floating production facility to date in the Gulf of Mexico. Production rates at year end averaged over 75 mboe/d.

Providing a strong foundation to our offshore portfolio are our Gulf of Mexico Shelf operations. BP accounts for 8% of the Gulf of Mexico Shelf production (Offshore Louisiana and Texas), which supplies 1/6th of the US natural gas market. We operate more than 200 platforms and 700 wells in up to 1,500 ft water depth. The Shelf is a mature basin with high decline rates, averaging 30-40% per year. In spite of that, we have maintained flat production over the last several years by utilizing advanced seismic technologies, reservoir studies, new completion technologies, and higher operating efficiencies. In 2001, we produced 198 mboe/d. We operated 12 rigs and drilled 61 operated wells.

Alaska

In Alaska, crude oil production in 2001 declined to 288 mb/d from a 2000 level of 314 mb/d. Despite this decline, we expect 2002 production in Alaska to be higher than 2001 due to the start-up of the Northstar field.

The current status of activity in Alaska is as follows:

-- Development is ongoing to mitigate the production decline at Alaska's largest producing field, Prudhoe Bay (BP 26.3% and operator). The overall observed decline rate for the Greater Prudhoe Bay Unit in 2001 was 16%. Production was characterized by continued decline in the Ivishak Producing Area and Greater Point MacIntyre Area, offset by increased production from new satellite fields.

-- The Borealis and Northwest Eileen fields (BP 26.3% and operator) came on line in the third quarter of 2001. Annualised satellite production averaged 13 mb/d (gross) for the year. By year-end, satellite field production had ramped up to 37 mb/d (gross). The satellite-drilling programme resulted in 19 new wells in the unit. The active drilling programme also resulted in the discovery of the new Orion Satellite.

-- Continued development of the Greater Prudhoe Bay Satellite fields in 2002 is expected to result in 34 additional wells and potential sanctioning of development of the Orion Satellite.

-- The Prudhoe Bay field continued an active infill drilling programme in 2001 with approximately 93 new and sidetracked wells. In 2002, we anticipate a 10% increase in the number of new and sidetracked wells.

-- The Northstar oil field (BP 99.1% and operator) was brought on line in October 2001 at a planned initial rate of 8 mb/d net and by December had reached a rate of 28 mb/d. The field is expected to reach a plateau rate of 50 mb/d net. BP's share of the full development cost is expected to be around $900 million.

-- Plans for the Point Thomson natural gas condensate field on the eastern North Slope have progressed in 2001. BP holds approximately 32% of this natural gas condensate field. While the field is expected ultimately to support a major natural gas pipeline off the North Slope, we are reviewing a project with natural gas sales as a future option, although no pipeline yet exists.

-- The Meltwater satellite development project at the Kuparuk field (BP 39.2%) began production in the fourth quarter of 2001. The field is expected to peak at about 20 mb/d gross.

-- In January 2002, we announced that we were suspending plans to develop the offshore Liberty field in favour of enhancing production at existing, large North Slope fields.

Lower 48 States

In the Lower 48 States, we remain the largest producer of natural gas, accounting for approximately 7% of total US onshore natural gas production. Production comes from a large number of fields situated principally in the states of Colorado, Kansas, Louisiana, New Mexico, Oklahoma, Texas and Wyoming.

In 2001, our production of oil and natural gas in the Lower 48 States was 620 mboe/d, up from 591 mboe/d in 2000 due to the full-year effect of the ARCO/Vastar acquisition in 2000. In 2001, we operated 34 drilling rigs and drilled 461 wells, adding reserves to replace 100% of production. Crude oil and NGL production was 213 mb/d, up 17% from 2000 levels. Natural gas production was 2,360 mmcf/d in 2001, up 9% from 2000 production.

Our production in the onshore Lower 48 States is derived primarily from the following assets:

-- In the mid-continent states (Kansas, Oklahoma, Texas and Louisiana) our operations produced 1,001 mmcf/d of natural gas and 11 mb/d of oil in 2001. Examples of improved efficiency to maintain rate in mature areas include:

    -- Western Kansas (Hugoton and Panoma fields) -- In 2001, through aggressive optimization of well operating conditions, we managed to hold production approximately flat in the Hugoton field. The Hugoton field is the largest natural gas field in the Lower 48 States and has previously experienced decline rates approaching 20%.

-- Oklahoma and Texas Panhandles (Anadarko Basin) -- We drilled and completed a 40 mmcf/d well, one of the biggest producing wells in recent history in the basin.

-- Louisiana (Tuscaloosa Trend) -- The Tuscaloosa asset set a new field production record of 373 mmcf/d in November 2001. The newly completed Martin No.1 well made a significant contribution to this record with a stabilized initial production rate of 80 mmcf/d.

-- Southeast Texas -- In the Northeast Thompsonville field, we successfully deployed the world's first commercial expandable liner hanger in a producing well. This technical innovation has the potential to reduce significantly drilling times (by reducing the number of trips) and safety risks (through its simpler design and ability to withstand higher pressures) on deep wells.

-- The Southern Wyoming (Overthrust Belt, Greater Green River Basin) operations produced 384 mmcf/d of natural gas and 9 mb/d of oil in 2001. Drilling activity has significantly increased in conjunction with a five-year drilling programme comprising more than 600 wells, primarily in the Jonah and Wamsutter fields. The 2001 drilling programme broke several field records, including most wells spudded in a single month (15), best drilling time (7.3 days/10,000 ft), and the deepest well drilled worldwide (9,500 ft) utilizing casing as the drill string. In other parts of the Greater Green River Basin, we achieved production growth of 20% through a combination of heavy drilling activity in the Jonah field and successful production base management in Moxa.

-- Colorado and New Mexico (San Juan Basin Coal and Conventional Gas fields) operations produced 832 mmcf/d of natural gas in 2001. Specific activities included the implementation of the Fruitland Coalbed Methane 160 acre infill programme and the final integration of BP and Vastar operations and personnel.

-- In the Permian Basin, 2001 production averaged 151 mmcf/d of natural gas and 55 mboe/d of liquids, an increase of 3% from 2000.

United Kingdom

We are the largest producer of both oil and natural gas in the UK. Our 2001 UK oil production of 485 mb/d was 49 mb/d lower than in 2000. Our UK natural gas production increased 4% from 1,652 mmcf/d in 2000 to 1,713 mmcf/d in 2001. The North Sea is a mature basin.

Our development expenditure in the UK (excluding pipelines) grew by 15% from $808 million in 2000 to $930 million during 2001. Significant 2001 activity included the following:

-- The Clair field Phase I development (BP 28.6% and operator) was sanctioned by BP and its partners in September, at an estimated net cost to BP of approximately $270 million. Currently the largest undeveloped resource on the UK Continental Shelf, the field was discovered in 1977 some 75 kilometres west of the Shetland Islands in 140 meters of water but was not developed due to technical difficulties. Advances in technology now make development of Clair commercially feasible. First production is expected in late 2004, with peak production rates of 20 mboe/d net in 2006.

-- The Foinaven field (BP 72% and operator), also west of the Shetland Islands in 600 meters of water, achieved a new production high of 138 mboe/d gross. This was in part due to production from the first two of five wells in Phase II, and in part due to first production from the East Foinaven field (BP 43% and operator) which began producing in September. East Foinaven is a subsea development consisting of three wells tied back to the Foinaven main field facilities. Starting in 2002, natural gas is planned to be exported from Foinaven and East Foinaven to Magnus through BP's newly constructed West of Shetland Pipeline System.

-- The natural gas pipeline which will support the Magnus Enhanced Oil Recovery Project (EOR) was completed. This pipeline will link the Magnus field (BP 85% and operator) to the deepwater west of Shetland Islands fields via the Sullom Voe Terminal Processing plant. Surplus natural gas from the Atlantic Margin fields is expected to flow beginning in mid-2002 into the Magnus reservoir and is expected to recover trapped oil which is expected to extend field life by some ten years and enable production at a plateau level of around 60 mboe/d gross until 2006. Surplus natural gas will be sold to market via existing pipelines.

-- The Bruce field (BP 37% and operator) saw the commencement of a two-year infill drilling programme. The second phase development of the Keith field (BP 35%) was sanctioned.

-- Harding field (BP 70% and operator) produced at a rate of 60 mb/d (gross) with the main part of the cluster (Harding South and Central) coming off plateau but being offset by production from satellite fields. The first infill well, part of a programme to fully exploit Harding South and Central reservoirs, was completed during the fourth quarter giving an additional 10 mb/d gross to the field. This well was the first UK Continental Shelf multilateral well with expandable sand screens. Further infill wells are expected to be drilled in 2002.

-- Maclure field development (BP 33.33% and operator) was sanctioned in December 2001 and is currently awaiting UK Government approval. Maclure is a subsea development with initial production rates of 12 mb/d oil and 3.5 mmcf/d natural gas expected to start up in mid-2002.

-- Eastern Trough Area Project (ETAP) production continued at high levels (108 mboe/d net) during 2001 despite the onset of natural decline in some of the initial fields (Machar in particular). During 2001 we increased our interest to 37.8% in the Madoes field (formerly known as Tornado) via an equity purchase from Phillips. We also sanctioned development of both Madoes and Mirren via subsea tieback to the ETAP central processing facility. First production from these satellite fields is expected in late 2002.

-- In the Southern North Sea area, there were a number of satellite and infill well activities. The North Davy well (BP 22% and operator), drilled in 2000, was successfully tied in and produced. The Amethyst Flowers well (BP 59.5% and operator) was also completed. The Hoton Project (BP 100% and operator) was completed on schedule with first production in December 2001.

-- A successful appraisal well was drilled to test an extension to the Vanguard field (BP 50%) and a development plan for the new field is under preparation.

-- The Shearwater Project (BP 27.5%) started production in mid-2001. Problems with plant and a number of wells were experienced, with net production averaging 7 mboe/d for the year. Production was shut down in December 2001 due to cracks in condensate pipework. We continue to work with the operator to restart production and to complete required remedial work on wells and pipework aimed at establishing steady state production during 2002.

Rest of Europe

Development expenditure in the Rest of Europe grew by 77% from $153 million in 2000 to $271 million in 2001.

Our Norwegian production increased from 95 mboe/d in 2000 to 108 mboe/d in 2001. Start-up of our Tambar field in July as well as new wells and increased efficiency at Ula are the main contributors to the increase. In addition, Draugen has increased field capacity in 2001. The natural decline of other fields has been offset by new wells at Valhall, the gas lift project at Hod and equal priority for Gyda at Ekofisk. Net production in 2001 was 40 mboe/d from Draugen (BP 18.4%), 26 mboe/d from Valhall (BP 28.1% and operator), 19 mboe/d from Ula (BP 80% and operator), 14 mboe/d from Gyda (BP 56% and operator), 6 mboe/d from Tambar (BP 55% and operator) and 2 mboe/d from Hod (BP 25% and operator). Appraisal activity included the Skarv oil and natural gas prospect (BP 30% and operator). The third Skarv well including a sidetrack was completed in June with positive results supporting a combined oil and natural gas development.

In the Netherlands, we are continuing to expand our role in natural gas storage services with the production and downstream natural gas marketing businesses working in close co-operation. The Peak Gas Installation, which came on stream in 2000, is a natural gas storage facility designed to assist in meeting peak demand requirements from consumers in the Netherlands. This installation has a storage capacity of 17,000 mmcf and is capable of withdrawing 1,270 mmcf/d.

Rest of World

The Group's net share of oil production from the Rest of World, including joint ventures and associated undertakings, increased to 602 mb/d in 2001 from 575 mb/d in 2000. Excluding joint ventures and associated undertakings production was 394 mb/d in 2001, up from 390 mb/d in 2000. Areas of oil production in 2001 were Abu Dhabi, Algeria, Angola, Argentina, Australia, Azerbaijan, Bolivia, Canada, China, Colombia, Egypt, Indonesia, Pakistan, Qatar, Russia, Sharjah, Trinidad and Venezuela.

Our share of natural gas production from the Rest of World, including joint ventures and associated undertakings, increased to 3,218 mmcf/d in 2001 from 2,767 mmcf/d in 2000. Excluding joint ventures and associated undertakings production averaged 2,873 mmcf/d in 2001, up from 2,504 mmcf/d in 2000. The largest part of 2001 production came from Trinidad and Tobago and from Indonesia, with the remainder from Argentina, Australia, Bolivia, Canada, China, Colombia, Egypt, Pakistan and Sharjah.

Canada, the Caribbean and South America

Development expenditure in the Rest of World (excluding pipelines) was $1,934 million in 2001, compared with $1,274 million in 2000, an increase of 52%.

-- In Canada, our portfolio covers a wide range of geographic areas, geological structures and infrastructure. Development activities within Canada are focused on opportunities to maintain production rates and position for growth within our existing core operating areas in the provinces of Alberta and British Columbia. In 2001, production was flat at 119 mboe/d, of which almost 85% was natural gas production (584 mmcf/d). BP has interests in 25 fields and operates approximately 1,200 wells (gross). During 2001 we operated 18 drilling rigs and drilled over 124 wells (gross).

Significant activity in South America in 2001 included the following:

-- The Colombian business is made up of mature producing assets (Cusiana/Cupiagua fields), assets under appraisal/development (Recetor and Florena fields) and a large prospect at the initial exploration stage (Niscota). Production for 2001 was 49 mboe/d. In 2001, the Florena field was successfully entered, ahead of schedule and with better than expected production rates. In addition, the successful Phase 1A development of the Recetor area, Cupiagua's northern extension, resulted in an additional commercial area and the acceleration of the overall Recetor development. BP has deepened its Recetor acreage equity from 63% to 80% (25% to 32% production equity).

-- In the Southern Cone, business in Argentina and Bolivia is conducted via our participation in Pan American Energy (PAE) in Argentina (BP 60%), which owns Empresa Petrolera Chaco in Bolivia.

Growth in 2001 was achieved in both oil and natural gas operations. These entities produced 50 mb/d of oil and 236 mmcf/d of natural gas (net to BP). Oil production increased by nearly 25% over 2000, largely as a result of a major drilling programme in Golfo San Jorge. Activity included infill and appraisal wells, water floods and electrification. Gas production increased by over 26% over 2000 with contributions from all operations. The most significant increase arose in Cerro Dragon and in the Northwest Basin where the first phase development of the Acambuco field came on stream during the first quarter of 2001.

Despite a severely depressed economy in Argentina, PAE was successful in increasing its natural gas market share from 9% to 12% during 2001. PAE also has significant interests in natural gas liquids plants, oil and natural gas pipelines, electricity generation plants, and other midstream infrastructure. Fiscal reform in Argentina is currently being debated and PAE management is actively involved in ongoing negotiations and in assessing the impact on our growth plans.

-- In Venezuela we produced 54 mboe/d from four core assets during 2001. These four base assets are reactivation projects consisting of two operated properties and two non-operated properties under operating fee agreements to produce oil for the government oil company, PDVSA. At the partner-operated Lake Maracaibo field (BP 27%), a slower than anticipated repressurization of the reservoir delayed and increased the uncertainty of oil production relative to the reactivation investment. Therefore we revised our reserve estimates downwards and recognized a charge for impairment of $175 million.

-- In Trinidad, production for 2001 reached 223 mboe/d (78% natural gas and 22% liquids) for 2001, up nearly 12% on 2000 production levels. Gas sales increased by 14% and liquid production increased by more than 3%. The increase in natural gas sales was principally due to increased purchases by The National Gas Company of Trinidad and Tobago. In late 2001, BP entered into an agreement to restructure certain natural gas contracts thereby providing for greater flexibility in choosing the field from which to source the natural gas. Major drilling activity in 2001 took place in the Mahogany and Amherstia fields, including several high rate wells one of which flowed at a rate of 200 mmcf/d.

Africa and the Middle East

Significant 2001 activity in Africa and the Middle East included:

-- In Angola Block 17 (BP 16.7%), the Girassol project went into production in December 2001 and ramp-up of production has gone well. The development of Jasmim, a tie-back to the Girassol hub, was approved. Additional development studies in Block 17, Rosa and Dalia, are well progressed.

Another significant milestone in Angola was achieved on Block 15 non-operated activities where the development approval of the large-scale Kizomba A (BP 26.7%) development (July 2001 sanction) was secured with first oil anticipated in 2004. Appraisal drilling commenced during the fourth quarter of 2001 with the aim of securing additional volumes to tie back to the Kizomba A hub and further improving Block 15 operating efficiencies. Future growth potential was also underpinned by progress on engineering studies for Kizomba B developments.

In Angola's BP operated Block 18 (BP 50% and operator), work has progressed well in the development engineering to determine the optimum development strategy for the six discoveries.

In Block 31 (BP 26.6% and operator), a dry hole was drilled and there is activity planned in 2002 to further delineate the Block.

-- In Egypt, our oil production operations are carried out by the Gulf of Suez Petroleum Company (Gupco), a joint operating company with the Egyptian General Petroleum Company (EGPC). Gupco operates seven production sharing contracts in the Gulf of Suez and Western Desert, encompassing more than forty fields. During 2001, Gupco produced 183 mb/d (87 mb/d net), almost 30% of Egypt's oil production, as well as 68 mmcf/d (33 mmcf/d net) of natural gas. Production operations were interrupted by a fire on the October platform in May 2001; October was fully back on line by the fourth quarter.

Gas production in Egypt grew 39% to 156 mmcf/d (net) with Ha'py (BP 50%) and Baltim (BP 50%) fields ramping up and the Temsah (BP 50%) natural gas field start-up was on schedule in March 2001. Collectively, we have agreements in place to supply 352 mmcf/d (working interest) to the domestic Egyptian market from these and other Nile Delta fields. The Akhen (BP 50%) drilling and development project was progressed in 2001 and the field is on schedule for production start-up in 2002.

In Egypt, BP has a 33% interest in the Med NGL project. The project involves the construction of a 1.1 bcf/d NGL plant. The plant is expected to start production in 2004, and should produce 280 thousand tonnes per annum (mtpa) of propane, 330 mtpa of LPG, and 2.7 mb/d of condensates.

-- Production in the Gulf States was dominated by the production entitlement of associated undertakings in Abu Dhabi where we have equity interests of 9.5% and 14.7% in onshore and offshore concessions expiring in 2014 and 2018, respectively. Production in Abu Dhabi was 126 mb/d, down from 2000 as OPEC cuts made an impact throughout 2001.

-- In addition, Sharjah natural gas production was down 13% on 2000 to 160 mcf/d, although the field decline would have been more severe without plant modifications and drilling in 2001.

-- In Algeria, BP and the Algerian state company, Sonatrach, completed natural gas sales terms and let engineering, procurement and construction contracts in August 2001 for the In Salah project (BP 65%). The first stage comprises a development of four of the seven deep Saharan natural gas fields; the development is expected to cost $2.7 billion gross. In Salah is expected to supply the fast growing markets of southern Europe with up to 320 bcf annually with first deliveries forecast for 2004.

-- The In Amenas (BP 100%) pre-project programme was progressed with contract bids for engineering, procurement and construction analysed, and final stage appraisal/pre-development drilling. The Rhourde el Baguel (BP 60%) gas injection facilities redevelopment has been completed.

-- In June 2001, we signed a memorandum of understanding to take a major interest in Saudi Arabia's largest natural gas development and the first significant hydrocarbons project for 25 years in which the Saudi government has invited foreign companies to participate.

-- In Iran we are carrying out studies of a potential redevelopment plan for the Ahwaz Bangestan fields and are conducting a feasibility study of a South Pars LNG project. At this stage, no agreements have yet been concluded that commit BP to any significant investments in Iran.

Asia

Significant 2001 activity in Asia (including the former Soviet Union) included:

-- BP, as operator of the Azerbaijan International Operating Company (AIOC), manages and has 34.1% interest in the Azeri-Chirag-Gunashli (ACG) oil fields in the Caspian Sea, offshore Azerbaijan. In 2001, ACG production grew to 35 mb/d net (119 mb/d gross) from the Chirag 1 platform and this early production is expected to plateau at 37 mb/d (127 mb/d) in 2002. The next step in the development of the ACG field was achieved in 2001 with the approval in August of ACG Phase 1 ($3.4 billion estimated gross capital expenditure). First oil is expected in 2005. Development engineering for ACG Phase 2 and Phase 3 was also progressed as the follow-on phases of development.

BP is also the operator of the Shah Deniz natural gas field with a 25.5% interest. Project definition progressed in 2001, predicated on a staged development concept. Shah Deniz Stage 1 is anticipated to come on-stream in 2005 comprising an offshore production facility, with platform and subsea wells, separate natural gas and condensate lines to shore, a processing terminal at Sangachal and a new 42-inch diameter natural gas line through Azerbaijan and Georgia to Turkey along the Baku-Tbilisi-Ceyhan route up to the Georgian/Turkish border. Boru Hatlari ile Petrol Tasima (BOTAS) in Turkey and State Oil Company of the Azerbaijan Republic (SOCAR) signed a Sales and Purchase Agreement (SPA) in March 2001. It is anticipated that this SPA, with appropriate amendments, will be assigned in full to Shah Deniz interest owners. Transit agreements with the Governments of Azerbaijan, Georgia, and Turkey to support the natural gas export pipeline (South Caucasus Pipeline) and natural gas sales, have also been completed.

-- In December, we announced that we had secured our ownership interest in the Russian integrated oil company A O Sidanco (Sidanco) and overseen the rightful return of the Chernogorneft producing assets during the fourth quarter of 2001. This completes the restructuring of Sidanco with its debt substantially repaid, and non-core assets disposed of. We believe that Sidanco is now positioned as a low cost Russian producer. As a result of transactions in 2001, we increased our production and beneficial interest to an effective 11.2% equity interest in Sidanco. We have a three-year management contract for Sidanco, acting with effectively a 25% voting interest. BP-seconded personnel hold a number of the senior management positions and a BP executive acts as Chairman of the Sidanco Board of Directors. We also have an interest in Kovytka (BP 28.4%), an undeveloped East Siberian natural gas field.

-- In Kazakhstan, we agreed to dispose of a non-strategic portion of our portfolio by selling surplus capacity in the Caspian Pipeline Consortium (CPC) (BP 5.75%) pipeline. We also agreed to sell our interest in the Kashagan field.

-- In Indonesia, BP is now the largest supplier of natural gas to Java. In addition, the VICO (BP 50%) operated Sanga Sanga production sharing contract (PSC) provides 30% of the natural gas feed into the Bontang LNG operation for export and East Kalimantan domestic consumption. Our share of Indonesian production in 2001 was 21 mb/d of liquids, 236 mmcf/d of natural gas sold to the Bontang LNG plant and 339 mmcf/d sold domestically in Indonesia. Under the terms of the PSC, the reported production entitlement varies inversely with price to effect recovery of costs which are fixed in US dollars; as prices decrease therefore, a higher entitlement is received.

-- In China, BP operates the Yacheng natural gas field and the Liu Hua oil field. Yacheng supplies 100% of the natural gas supply into Hong Kong where it is sold to Castle Peak Power Company (CAPCO) under a long-term contract. Excess natural gas and liquids are piped to Hainan Island where the natural gas is sold to the Fuel and Chemical Company of Hainan also under a long-term contract. The QHD oil field (operated by CNOOC) began production in October and is expected to reach plateau during the fourth quarter of 2002.

BP's Hedong Coal Bed Methane (CBM) (BP 70%) project is located in the Ordos Basin in Shanxii province approximately 800 kilometers southwest of Beijing. BP has met all the contractual obligations of the Production Sharing Agreements and, after two years of pilot production testing, has decided to exit the project for technical reasons.

-- In Vietnam, BP (35% and consortium leader) and partners signed key elements of a $1.3 billion integrated natural gas project at the end of 2000. Construction of the Block 06.1 natural gas development and associated infrastructure commenced in early 2001 and is now well advanced. This scheme is intended to provide the basis for clean, reliable gas-fired power generation in southern Vietnam. First production is planned for late 2002.

-- In Pakistan, BP is the largest foreign operator producing 50% of the country's oil and 10% of its natural gas on a gross basis.

Midstream Activities

Oil and Natural Gas Transportation

The Group has direct or indirect interests in certain crude oil transportation systems, the principal ones of which are the Trans Alaska Pipeline System in the USA and the Forties Pipelines System in the UK sector of the North Sea. We also operate and have an interest in the Central Area Transmission System for natural gas in the UK sector of the North Sea. Our onshore US crude and product pipelines and related transportation assets are included under 'Refining and Marketing'. Our gas marketing business is described under 'Gas and Power'.

-- The Trans Alaska Pipeline System (TAPS) consists of a 48-inch diameter crude oil pipeline running approximately 1,300 kilometers from Prudhoe Bay to a tank farm and marine terminal at the ice-free port of Valdez on Alaska's southern coast. The Alyeska Pipeline Service Company operates the pipeline and terminal at Valdez. As part of the equity alignment related to ownership of the Prudhoe Bay Unit and Point Thompson Unit, BP sold 3.1% of its interest to Phillips in 2001.

-- BP now owns a 46.9% interest in TAPS, with the balance owned by five other companies. Each of the TAPS participants uses its undivided interest in TAPS as a common carrier, separately publishing tariffs and receiving tenders for shipments through its share in the capacity of TAPS, and paying its volumetric share of operating costs. At peak throughput, the TAPS system carried around 2 mmb/d. In 2001, TAPS transported production from Prudhoe Bay and the other North Slope fields averaging 1 mmb/d. In October, TAPS was vandalized and punctured by a bullet, resulting in a leak of 6,600 bbls of oil. Following a shut-in of 62 hours for repair, during which 730,000 barrels (net) of production was lost , full operation was restored. Clean-up operations continue into 2002. Security measures on the line and at the North Slope fields were increased in September and remain at a high level.

For a description of the procedures relating to the tariffs to be charged to users of TAPS and a general description of pipeline regulation, see Regulation of the Group's Business -- United States within this item.

There are a number of unresolved protests with regard to the yearly tariffs which are filed and which set out the charges for shipping oil through TAPS. These items are in the process of resolution at the Federal Energy Regulatory Commission (FERC) and the Regulatory

Commission of Alaska.

The use of US-built and US-flagged ships is required when transporting Alaskan oil to markets in the USA. In accordance with this, BP America Inc. has a chartered fleet of 10 US-flagged tankers to transport Alaskan crude oil to markets. Over the next few years, we plan to begin replacing our US-flagged fleet as existing ships, whose average age is 23.3 years, are retired in accordance with the Oil Pollution Act of 1990. For discussion of the Oil Pollution Act of 1990, see Regulation of the Group's Business -- Environmental Protection. In September 2000, BP contracted for the delivery of three 1.3 million-barrel-capacity, double-hull tankers for use in transporting North Slope oil to West Coast refineries. The ships are being constructed by NASSCO in San Diego with deliveries in 2003, 2004 and 2005. In 2001, BP exercised the first of three options for additional vessels. This fourth tanker is scheduled for delivery in 2006.

-- The Forties Pipeline System in the UK (BP 100%) is an integrated oil and natural gas liquids transportation and processing system that handles production from over 40 fields in the central North Sea. The system was upgraded in 1993 and has a capacity of more than 1 mmb/d. During 2001, average throughput was approximately 783 mb/d, compared with 804 mb/d in 2000.

-- BP operates and has a 29.5% interest in the Central Area Transmission System (CATS), a 400-kilometre natural gas pipeline system in the central UK sector of the North Sea. The pipeline has a transportation capacity of 1.7 bcf/d. It carries both proprietary and other companies' volumes to a natural gas terminal at Teesside, Northeast England. CATS offers its customers the choice of natural gas transportation services or transportation and processing via two 600 mmcf/d processing trains with the capability to deliver NGLs for export or for local industry with natural gas entering the UK National Transportation System. In 2001 CATS handled throughput of 1.6 bcf/d.

-- BP, as AIOC operator, manages and has a 34.1% interest in the Western Export Route Pipeline between Sangachal, which is near Baku in Azerbaijan, and Supsa on the Black Sea coast of Georgia. AIOC also operates the Azeri leg of the Northern Export Route Pipeline between Sangachal and Novorossiysk in Russia. The combined capacity of the pipelines is in excess of 200 mb/d. Transit agreements were completed with the governments of Azerbaijan, Georgia, and Turkey to support implementation of a 1 mmb/d pipeline from Baku to Ceyhan via Tbilisi on the Turkish Mediterranean coast. BP along with seven partners in the consortium to promote development of the BTC pipeline have completed a number of Host and Inter-Government Agreements in 2001, including one for Georgia. Front-End Engineering Design has been started. The additional export capacity provided is expected to be largely taken by future production from ACG and other Azerbaijan developments.

-- In October 2001 CPC (BP 5.75%) commissioned a 1,510 kilometre pipeline from Kazakhstan to the Russian port of Novorossiysk. The pipeline has an initial capacity of 28.2 million tonnes a year and will carry crude from the Tengiz field (BP 2.3% through the Lukarco joint venture).

-- A joint study team, including BP and the other major North Slope natural gas resource owners, is nearing completion of a major study investigating a pipeline project to deliver Alaskan natural gas to major North American markets. Key activities in 2002 will be to mitigate the risks inherent in a project of this magnitude, including working with legislative bodies to establish an appropriate regulatory framework.

Liquefied Natural Gas

Within BP, the Exploration and Production business is responsible for the supply of Liquefied Natural Gas (LNG) and BP's Gas and Power stream is responsible for the subsequent marketing and distribution of LNG (see details under 'Gas and Power -- International Gas and LNG').

-- BP has a 34% interest in the first train of the Atlantic LNG plant in Trinidad and is the sole supplier of natural gas to this train, which commenced operations in February 1999. In the fourth quarter of 2000, government and partner approvals were obtained to expand Atlantic LNG by an additional two trains. In 2001, construction of Train 2 progressed as planned, with first sales expected in the third quarter of 2002. Gas for Train 2 will come from the Amherstia field (BP 100% and operator) initially. To enable delivery of gas to Atlantic LNG's planned Train 3, BP is constructing its biggest offshore gas processing platform (Kapok) and its largest offshore pipeline (Bombax). Construction is proceeding on schedule to meet the planned start-up of Train 3 in 2003. Also in 2001, the Front-End Engineering and Design for a fourth LNG train was started. BP is expected to supply at least 34% of the natural gas requirements for this 4.8-mtpa (millions of tonnes per annum) plant.

-- In Trinidad and Tobago, we announced our agreement to hold a 37% share in the Atlas methanol plant, with Methanex, the Canadian operator, holding the remainder. Atlas is expected to be the largest methanol plant ever built and is intended to set new standards for cost, efficiency and environmental emissions as a result of the use of innovative leading edge technology. BP, through its customer NGC, will supply 100% of the natural gas demand for the plant.

-- In Indonesia, the VICO (BP 50%) operations produced 1.21 bcf/d of the natural gas supply to the LNG plant at Bontang; of this total, 236 mmcf/d is the BP net share. VICO, as well as operating the extensive East Kalimantan pipeline network, is natural gas co-ordinator for all of the 4 bcf/d natural gas feedstock to the Bontang facility and is Technical Advisor to PT Badak, the LNG plant operating company. Bontang, currently the world's largest LNG facility, consists of eight LNG trains with a nominal total capacity of 22.6 mmtpa, with the possibility of expanding to a ninth train being considered.

-- In addition, we operate the Wiriagar and Berau fields in Papua. These should provide the largest share of natural gas feed to the Tangguh LNG project which is expected to become the third LNG centre in Indonesia, the world's largest LNG-producing country.

-- In early 2001, BP was selected as the leading foreign company (BP 30% equity share) in China's first LNG re-gasification terminal project near Shenzhen in Guangdong Province. Planned activities in 2002 include the completion of the feasibility study and the formation of the joint venture company. The terminal is expected to start-up in late 2005 and is planned initially to have a capacity of 3.2 mmtpa with the ability to be expanded well beyond that.

-- In 2002, construction is expected to be completed on an $86 million gas-to-liquids demonstration unit, located in Nikiski, Alaska. This plant will utilize BP's compact reformer technology, enabling a significant improvement in gas-to-liquids commercial competitiveness.

Plant start-up is scheduled for second quarter of 2002.

- In Australia, our interest in the North West Shelf Venture (BP 16.7%) saw BP's production increase 3.3% to 80.6 mboe/d in 2001. Growth was gas-led by LNG (up 0.9 mboe/d) and domestic natural gas (up 1.6 mboe/d). Along with production growth, cost savings were a considerable value driver yielding $25 million of additional earnings. In April 2001, construction of LNG Train 4 was sanctioned. The Train, scheduled to commence in June 2004, should increase North West Shelf LNG capacity by approximately 50%. In December 2001, two Echo Yodel condensate wells were commissioned, three months earlier than initially planned.

- We have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company (ADGAS), which in 2001 supplied 5.4 million tonnes of LNG, up 4% on 2000.

GAS AND POWER

The Gas and Power business was created to market our substantial natural gas reserves and to develop a leading gas and power marketing and trading business. Since its inception, we have been investing in both organizational capability and capital assets to grow this new business segment.

The business is organized into three activities: natural gas marketing and trading; international natural gas and liquefied natural gas (LNG); and power activities. On January 1, 2001, the NGL business, located in North America, was transferred to the Gas and Power business from Refining and Marketing and is included in the marketing and trading activities. On January 1, 2002, the solar, renewables and alternative fuels business activities were transferred to the Gas and Power business from Other Businesses and Corporate. Also from that date the segment has been renamed Gas, Power and Renewables.

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Turnover	39,208	21,013	8,073
Total replacement cost operating profit	521	571	437
Total assets	5,313	6,605	2,831
Capital expenditure and acquisitions	359	336	81

Marketing and trading activities within the stream are focused on the relatively open and liberalized natural gas and power markets of North America, the United Kingdom and certain parts of the Rest of Europe, although elements of long-term natural gas contracting activity are also still included within the Exploration and Production business segment. Our business is built on the foundation of our major natural gas supply reserves being within or in close proximity to these markets. As natural gas and power markets converge, our entry into power marketing and trading is a logical extension of our natural gas business. We market and trade BP and third-party natural gas and, to a much lesser extent, power and related energy management services. Our NGL business, a part of our North America marketing and trading activities, is engaged in the processing, fractionation and marketing of ethane, propane, butanes and pentanes extracted from natural gas.

International natural gas and LNG activities involve developing opportunities to monetize our upstream natural gas resources, and as such, are conducted in close collaboration with the Exploration and Production business. Our international natural gas strategy is to capture a disproportionate share of growth in the international demand for natural gas and is focused on growing natural gas markets including the USA, Canada, Spain and many of the emerging markets of the Asia Pacific region, notably China, where substantial demand growth is expected. LNG activities are focused on the marketing and trading of BP and third party LNG. There is close linkage between the LNG supply activities in the upstream business and Gas and Power's LNG marketing and trading activities.

In addition to power marketing and trading activities noted above, we are involved in several gas-fired power generation projects. Our power strategy focuses on projects that either monetize our equity natural gas and/or cogeneration projects on Group sites that contribute additional value from the reduction of Group power costs and/or enable excess power to be sold.

Marketing and Trading Activities

Our marketing and trading activities are concentrated in the markets of North America and the United Kingdom. Gas sales volumes have increased from 14.5 bcf/d in 2000 to 18.8 bcf/d in 2001. Most of this growth was realized in North America.

	Years ended December 31,		
Gas sales volumes (a)	2001	2000	1999
	(million cubic feet per day)		
UK	2,641	2,526	1,693
Rest of Europe	213	178	167
USA	8,327	6,524	4,047
Rest of World	7,613	5,243	3,023
Total	18,794	14,471	8,930

(a) Includes marketing, trading and supply sales.

Our policy toward natural gas price risk is described in Item 11 -- Quantitative and Qualitative Disclosures about Market Risk.

36

North America

BP is the leading natural gas producer in North America, the world's largest natural gas market. We are building our natural gas and power marketing and trading business in North America upon this strong foundation. Our North

American total natural gas sales volumes have grown from 5.4 bcf/d in 1999 to 9.7 bcf/d in 2000 and to 13.4 bcf/d in 2001. Of these volumes, 4.1 bcf/d (2000 3.6 bcf/d) were supplied from BP upstream producing operations. The sales volumes were a mixture of sales to commercial and industrial customers, sales to trade counter parties and term sales.

Our North America natural gas marketing and trading strategy seeks to maximize returns from building a distinctive network of connected assets, customers and activities thereby optimizing our portfolio and supply chain management and adding value through trading. These assets could be owned by BP or contractually accessed through agreements with our customers or other third parties. The extension of this network of assets is the principal purpose of our capital expenditure programme in North America for our marketing and trading activities.

	Years ended December 31,		
NGL sales volumes	2001	2000	1999
	(thousand barrels per day)		
UK	--	--	--
Rest of Europe	--	--	--
USA	221	154	115
Rest of World	189	195	192
Total	410	349	307

The transfer of the North American NGL business to Gas and Power in 2001 recognizes that NGLs are an integral part of the overall natural gas value chain and will also take advantage of our natural gas marketing and trading skill base in North America. The majority of BP's NGLs are marketed on a wholesale basis under annual supply contracts that provide for price redetermination based on prevailing market prices. 2001 sales volumes of NGL averaged 410 mb/d (2000 349 mb/d). NGLs are also supplied to our chemical and refining activities. We operate natural gas processing facilities across North America with a total capacity of 8.3 bcf/d. We own or have an interest in five fractionator plants in Canada and the United States. Two of these are located in Canada in Fort Saskatchewan, Alberta and Sarnia, Ontario, and three are located in the United States in Hobbs, New Mexico, Baton Rouge, Louisiana and Mont Belvieu, Texas.

United Kingdom

The natural gas market in the UK is significant in size and is one of the most progressive in terms of deregulation when compared with other European markets. BP is the largest producer of natural gas in the UK. Total natural gas sales in the UK were 2.5 bcf/d in 2001, 2.5 bcf/d in 2000 and 1.7 bcf/d in 1999. Of these volumes 1.7 bcf/d (2000 1.7 bcf/d and 1999 1.3 bcf/d) were supplied from our upstream producing operations. Some of the natural gas is sold under long-term natural gas supply contracts to customers such as Centrica, the largest distributor of gas in the UK. However, the majority of natural gas sales are to commercial and industrial customers, power generation companies and via long-term supply deals with other gas wholesalers. We also trade physical natural gas on the UK spot market.

From October 1, 2001 we have agreed to purchase 56 bcf of natural gas per annum for 15 years from Statoil, a Norwegian oil and natural gas producer. This is the first significant contract for natural gas supplies to the UK from the

Norwegian continental shelf since the Frigg contract in 1977.

We have a 10% interest in the Interconnector, a 1.9-bcf/d, 240-kilometre, 40-inch sub-sea natural gas pipeline between Bacton in the UK and Zeebrugge in Belgium, which effectively links the natural gas markets of the UK and Continental Europe.

Rest of Europe

We are continuing to build a natural gas and power marketing and trading business in northern and southern Europe. Our interest in the European market is driven by the size and growth potential of the market, deregulation and the proximity of BP natural gas supplies.

In northern Europe, we have established marketing activities in the Netherlands, Belgium, France and Germany. In March 2001, we acquired a 51% interest in Pmax Portfolio Management GmbH (Pmax), based in Hamburg, Germany. Pmax is an electricity marketing company, which markets electricity to medium and large customers in Germany. This investment has enabled the growth of our energy marketing business in Germany and extends our energy services and trading opportunities within northern Europe.

As part of the Veba deal, we announced the proposed divestment of our 25.5% interest in Ruhrgas. This sale has since been prohibited by Germany's Federal Cartel Office although the decision is being appealed to the German Economics Ministry, which is expected to rule in mid-2002.

In southern Europe we maintained our focus on Spain and Italy. The Spanish natural gas market has continued to grow and it is liberalizing largely ahead of the rest of continental Europe. We built on our position of being the first foreign company to secure a licence permitting us to market natural gas to industrial consumers outside the former monopoly, by growing the business to maintain some 7% of the eligible industrial market by the end of 2001. To achieve our growth, BP emerged with the maximum 25% share allowed from the Release Gas programme run by the Spanish authorities (this was the programme which required the incumbent Spanish natural gas supplier, Gas Natural, to release 150 bcf of natural gas to new entrants over a 2 year period from December 2001) and we added a major LNG supply contract from a Middle Eastern supplier backed by leasing an LNG carrier. We used the power commercializer license we were awarded in December 2000 to market power to a set of test industrial consumers in Spain's liberalized power market. Italy continues to be a significant and growing natural gas and power market (the second largest in Continental Europe) which is liberalizing and presenting opportunities to us.

International Gas and LNG

Our international natural gas and LNG activities are focused on developing worldwide opportunities to capture international natural gas growth and to monetize our upstream natural gas resources.

Construction is underway on the Bahia de Bizkaia project in Bilbao, Spain, an integrated 97.1 billion cubic feet per annum LNG import/regasification and 800 megawatt combined cycle, gas-fired power generation facility. BP has a 25% equity share in the facility and BP equity natural gas from Trinidad and Tobago will supply the facility. After regasification of the LNG, approximately 40% of the natural gas will feed the power plant, while the remaining natural gas will be fed into the local natural gas distribution system.

China is another area of activity. Currently, natural gas meets only two percent of China's energy needs, but this is expected to increase significantly. BP announced in March 2000 that it had plans to form a natural gas marketing joint venture with PetroChina aimed at supplying the growing energy markets of eastern China. Longer term, the alliance allows BP to be involved in marketing natural gas from East Siberia where BP has an interest in the substantial undeveloped Kovyktinskoye field. In 2001, BP was selected as the foreign partner in the joint venture tasked to develop the Guangdong project, China's first LNG import terminal near the city of Shezhen. Phase 1 of the project will have a capacity of 3 million tonnes a year and an associated 300 kilometres of pipeline to link the terminal to the region. Guangdong is due on stream in 2006.

In a major step forward for the Pertamina and BP operated Tangguh LNG Project in eastern Indonesia, Pertamina signed a Letter of Intent (LOI) in November 2001 for delivery of LNG to GNPower of the Philippines. The LOI provides for an exclusive period for Pertamina and GNPower to negotiate the supply of LNG from Tangguh field.

The development of the LNG business requires the development of appropriate LNG shipping capacity. During 2000, BP ordered two LNG tankers from Samsung Heavy Industries for delivery in 2002 and 2003, together with options for a further three ships. The first of these options was exercised in the first quarter of 2001 for delivery in 2003.

As described under the heading Exploration and Production -- Midstream activities -- Liquefied Natural Gas, our major LNG supplies are from Trinidad and Tobago, VICO in Indonesia, ADGAS in Abu Dhabi and the North West Shelf in Australia.

Power Activities

This business sector primarily participates in (i) power projects that support monetization of our equity natural gas and (ii) cogeneration projects on advantaged BP sites e.g., refining and chemical manufacturing sites. In addition to power marketing and trading discussed above, we are also involved in three power generation construction projects, including the Bahia de Bizkaia project covered above.

38

Following the announcement of power development plans at BP's largest refining and petrochemical complex, located in Texas City, Texas, construction work at the site began in 2001 for the development of a 570-megawatt (MW) cogeneration plant as a 50:50 joint venture with Cinergy Solutions, Inc. This project is expected to provide low-cost steam, power and process heat to our refining and chemicals businesses. The project is further expected to provide improved generation efficiency, reduced power costs and reduced nitrogen oxide emissions at the site. BP will supply natural gas to the plant and its excess generation capacity will be used to support power marketing and trading activities.

In December 2000, our 400 MW gas-fired power plant project at Great Yarmouth in the UK entered its commissioning phase. Commissioning has been delayed throughout 2001 due to technical problems. Work is underway with the view to making it fully operational during 2002. We plan to operate this project as a merchant plant, i.e. a power plant that sells electric power to 'spot' customers, and BP is expected to provide natural gas to the plant.

REFINING AND MARKETING

Our Refining and Marketing business is responsible for the supply and trading, refining, marketing and transportation of crude oil and petroleum products to wholesale and retail customers. BP markets its products in over 100 countries. It operates primarily in Europe and North America, but also markets its products across South America, Australasia and in parts of South East Asia and Africa.

	Years ended December 31,		
	2001	2000	1999
		($ million)	
Turnover (a)	120,233	107,883	60,143
Total replacement cost operating profit	3,625	3,523	1,614
Total assets	43,102	45,785	26,099
Capital expenditure and acquisitions	2,415	8,693	1,571
		($ per barrel)	
Global Indicator Refining Margin (b)	4.06	4.22	1.24

(a) Excludes BP's share of joint venture turnover of $403 million in 2001, $13,112 million in 2000 and $17,117 million in 1999.

(b) The Global Indicator Refining Margin (GIM) is the average of seven regional indicator margins weighted for BP's crude refining capacity in each region. Each regional indicator margin is based on a single representative crude with product yields characteristic of the typical level of upgrading complexity.

There are four key components of the Refining and Marketing stream each with its own focus and strengths. In refining, the focus is on top-quartile performance; to measure this we primarily use the regional refining surveys by Solomon Associates to assess our competitive position against benchmarked industry measures such as costs per barrel. In retail, the focus is on high-growth geographical areas and customer segments through the convenience-store market. In lubricants, the focus is on capitalizing on the leading Castrol and BP brands, potentially giving increased growth in both margin and volume. Finally, with respect to the stream's commercial and industrial activities, such as aviation, we focus on attractive customer segments to capture margin and growth.

Refining and Marketing manages a portfolio of assets that we believe are competitively advantaged across the chain of downstream activities. Such advantage may derive from several factors, including location, operating cost and physical asset quality.

We are one of the leading refiners and marketers of gasoline and hydrocarbon products in the USA. We have extensive retail and commercial businesses in the UK, the Rest of Europe, Australasia, Africa and South East Asia. Worldwide, BP continues to be a leading marketer of fuels, served by a refining network with key refineries among the top performers in their regions.

The merger of BP and Amoco on December 31, 1998 and the acquisitions of ARCO, Burmah Castrol and ExxonMobil's interest in the fuels business of the BP/Mobil European joint venture in 2000 substantially strengthened our position in refining and marketing in the USA, UK, and Western Europe.

With effect from February 1, 2002, BP acquired Veba Oil's retail and refining assets in Germany and Central Europe. The Veba acquisition makes BP the market leader in Germany and Austria, and substantially strengthens BP's position in Poland and in several other Central European countries. Veba's retail stations are branded Aral. Veba has interests in five high quality clean fuels refineries in Germany.

In 2001, BP completed the integration of Burmah Castrol, sold its Mandan, North Dakota, and Salt Lake City, Utah refineries and restructured its commercial business in Northern Europe. Growth in the number of employees in other areas was more than offset by these activities with employee numbers decreasing from 67,000 at the start of the year to 64,600 at the year end.

40

Refining

In refining, our key objective is to safely operate an advantaged refining system more profitably than those of our competitors. For BP, advantaged characteristics relate to supply - the refinery's position in relation to the market; clean fuels - how the refinery supports our clean fuels strategy; and integration value - how the refinery adds value by virtue of integration with other parts of the Group's business. Refining's focus remains continued safe, reliable, and efficient operations, income growth, and increased supply of cleaner burning transport fuels for BP's Clean Cities programme.

In line with the Company's global refining strategy, to retain only those refineries that either provide advantaged supplies for its marketing operations, or are integrated with other parts of the business, BP completed the sale of its Salt Lake City, Utah, and Mandan, North Dakota refineries to Tesoro, on September 6, 2001. BP has reached agreement with Giant Industries, Inc. for Giant to acquire BP's wholly owned Yorktown, Virginia refinery; the sale is anticipated to close in the second quarter of 2002. BP has also announced the intention to sell its 33% equity interest in the Singapore Refining Company (SRC).

In the US, BP owns and operates five large modern fuels refineries with extensive clean fuel capability consistent with our strategy. These are located in Texas City, Texas; Whiting, Indiana; Toledo, Ohio; Carson City, California; and Cherry Point, Washington.

In Europe, BP operates seven fuels refineries. These are Bayernoil in Germany, Castellon in Spain, Coryton and Grangemouth in the UK, Lavera in France, Mersin in Turkey, and Nerefco in the Netherlands. All are wholly owned by BP except Bayernoil, Mersin, and Nerefco, where BP's equity interests are 55%, 68%, and 69%, respectively. Additionally, BP has a 17% equity interest in the Reichstett refinery in France, and wholly owns the Hamburg, Germany lubricants refinery. BP has announced a major restructuring project at the Grangemouth refinery in 2002 to increase the long-term competitiveness of the refinery and chemical complex.

In the rest of the world BP operates three principal refineries. These are located at Bulwer Island, Australia, Kwinana, Australia, and Singapore. Both Australian refineries are wholly owned by BP.

BP also has a 50% interest in the Durban, South Africa refinery, a 24% interest in the Whangarei, New Zealand refinery, and a 13% equity interest in the Mombasa, Kenya refinery.

With effect from February 1, 2002 BP acquired a 51% stake in Veba Oil. Veba Oil owns the Lingen refinery and has interests in four other refineries - Gelsenkirchen (50%), Schwedt (18.75%), Miro (12%), and Bayernoil (12.5%). These interests are held through Ruhr Oil, a 50/50 joint venture with Petroleos de Venezuela SA (PdVSA). Veba's total net refining capacity amounts to roughly 310,000 barrels per day. Besides adding refining capacity in advantaged geographic areas, we believe that the addition of these plants will significantly enhance BP's clean fuels capability within Central Europe.

The following table outlines by region the volume of crude oil and feedstock processed by BP for its own account and for third parties, and for the Group by other refiners under processing agreements. Corresponding BP refinery capacity utilization data are summarised.

	Years ended December 31,		
Refinery throughputs	2001	2000	1999
	(thousand barrels per day)		
UK (a)	364	324	271
Rest of Europe (a)	663	602	540
USA	1,526	1,625	1,340
Rest of World	376	365	371
	2,929	2,916	2,522
For BP by others	14	12	19
Total	2,943	2,928	2,541
Refinery capacity utilization			
Crude distillation capacity at December 31, (a) (b)	3,259	3,203	2,801
Crude distillation capacity utilization (c)	94%	95%	95%
USA	95%	97%	95%
Europe	94%	96%	94%
Rest of World	93%	87%	96%

(a) Includes the BP share of the BP/Mobil joint venture until August 1, 2000.

(b) The crude distillation capacity figures are based on gross rated capacity, which assumes no loss of capacity due to shutdowns. The figures for 2001 reflect the sale of the Salt Lake City, Utah and Mandan, North Dakota refineries. The figures for 2000 reflect the unwinding of the BP/Mobil European joint venture, the Alliance, Louisiana refinery sale, and the acquisition of ARCO's two west coast fuels refineries: Carson City, California and Cherry Point, Washington.

(c) Crude distillation capacity utilization is defined as the percentage utilization of capacity per calendar day over the year after making allowances for average annual shutdowns at BP refineries (i.e. net rated capacity).

Marketing

Marketing comprises three business areas: Retail, Commercial and Industrial, and Lubricants. We market a comprehensive range of refined oil products worldwide. These products include gasoline, gasoil, marine and aviation fuels, heating fuels, LPG, lubricants and bitumen.

The following table sets out refined product sales by area. A significant increase in sales was achieved in 2001 as a result of the full year impact of the acquisition in 2000 of ARCO, Burmah Castrol and ExxonMobil's interests in the BP/Mobil European fuels business.

	Years ended December 31,		
Sales of refined products (a)	2001	2000	1999
	(thousand barrels per day)		
Marketing sales:			
UK (b)(c)	266	256	235
Rest of Europe (b)	1,062	901	794
USA	1,866	1,783	1,427
Rest of World	603	480	423
Total marketing sales (d)	3,797	3,420	2,879
Trading/supply sales (d)	2,409	2,103	1,816
Total refined products	6,206	5,523	4,695
	($ million)		
Proceeds from sale of refined products (b)	82,241	74,239	41,497

(a) Excludes sales to other BP businesses.

(b) Includes the BP share of the BP/Mobil European joint venture until August 1, 2000.

(c) UK area includes the UK-based international activities of Refining and Marketing.

(d) Marketing sales are sales to service stations, end-consumers, bulk buyers, jobbers and small resellers. Trading/supply sales are to large unbranded resellers and other oil companies.

The following table sets out marketing sales by major product group:

Marketing sales by product	2001	2000	1999
	Years ended December 31, (thousand barrels per day)		
Aviation fuel	515	474	366
Gasolines	1,659	1,512	1,298
Middle distillates	1,077	945	765
Fuel oil	351	338	319
Other products	195	151	131
Total marketing sales	3,797	3,420	2,879

In marketing our aim is to grow our customer base, both in existing and new markets - in terms of attracting new customers and by covering a wider geographic area. We are aiming at increasing our revenue per customer by attracting retail customers to spend more in convenience stores and business customers to spend more on value-added services and solutions.

Our objective is to create a more capital-efficient, higher-return business by differentiating where we choose to invest directly from where we seek to invest through partners. In addition we recognize that our customers are demanding a wider choice of fuels, particularly fuels that are cleaner and more efficient. Through our integrated refining and marketing operations we believe we are able to meet these customer needs.

During 2001 we continued implementation of our clean fuels initiative with BP marketing cleaner fuels in 113 cities at December 31, 2001.

Retail

In retail, we differentiate between two distinct segments: a fuels segment in which we only supply fuel to retail customers through dealers and jobbers, and a convenience segment, incorporating an integrated fuel and convenience store offering, the operation of which will either be directly managed or franchised. We plan to concentrate our investment primarily in developing additional store space on existing real estate in our core metropolitan markets.

Shop sales (a)	2001	2000	1999
	Years ended December 31, ($million)		

UK	458	357	265
Rest of Europe	904	663	569
USA	1,510	1,251	542
Rest of World	362	353	365
Total	3,234	2,624	1,741
Direct-- managed	1,650	1,397	994
Franchise	1,504	1,154	707
Shop alliances	80	73	40
Total	3,234	2,624	1,741

(a) Shop sales reported are sales through direct-managed stations, franchisees and the BP share of shop alliances. Sales figures exclude sales taxes and lottery sales but include quick service restaurant sales. The sales include the BP share of the relevant sales within the BP/Mobil European joint venture until August 1, 2000.

Our retail network is concentrated in Europe and the USA, with established operations in Australasia and Southern Africa as well. We are developing networks in China, Poland and Russia.

In 2001, we opened 335 new BP Connect sites primarily in the UK and US as part of our retail strategy that builds on our advantaged locations, strong market positions and brand. These new BP Connects include new sites, razed and rebuilt sites, and extensive upgrading and remodeling of some existing stations. The BP Connect sites offer our customers cleaner fuels, a wider range of services and a distinctive food offer. In addition, over 4,600 stations worldwide were reimaged to the new BP Helios.

At the same time as we are rolling out the new convenience offer, we continue to improve the efficiency of our retail network by reducing operating costs through a process of regularly reviewing the network. Actions taken during 2001 have included divesting sites and networks, principally in those markets where our growth will be focused on a fuels only offer delivered through dealers and jobbers. Alongside this activity, we have continued to upgrade existing sites and invest in new sites, principally in markets where we believe there is growing demand for our full convenience offer.

At December 31, 2001, there were approximately 26,800 BP, Amoco and ARCO branded service stations worldwide, some 2,200 less than at the end of 2000. The Veba Oil acquisition will add approximately 3,000 Aral-branded stations in Central Europe prior to regulatory required divestments. Subsequent to the integration of the Aral-branded stations the worldwide number of stations is expected to decline over the next few years as we continue to optimize the efficiency of our retail network.

At December 31, 2001, BP's retail network in the USA comprised about 15,500 service stations of which approximately 10,600 were jobber owned. Developments in the USA during 2001 included the divestment of about 500 service stations in line with the strategy to concentrate ownership of real estate in markets designated for development of the convenience offer and stations and jobbers previously supplied from BP's Mandan, North Dakota and Salt Lake City, Utah refineries. In the US, we opened 196 BP connect sites and reimaged 1,525 stations to the new BP Helios.

In the UK and the Rest of Europe, BP's network comprised about 7,500 service stations at December 31, 2001. We opened 80 BP Connects in Europe with the majority being in the metropolitan London area and reimaged throughout Europe approximately 3,000 stations to the new BP Helios image. The Veba acquisition has significantly strengthened our retail position in Germany and Central Europe making BP the market leader in Germany and Austria by adding over 2,500 stations in Germany and 155 stations in Austria. In Central Europe, Aral has over 130 stations in the Czech Republic, Slovakia and Hungary. The combination of the BP and Aral network in Poland makes BP the largest foreign oil company in Poland with over 270 stations. In Russia, we continued to expand our retail network by adding seven stations in 2001 bringing our total number of stations in the Moscow metropolitan area to 34 at December 31, 2001.

At December 31, 2001 BP's retail network in the rest of the world comprised some 3,800 service stations. Our established networks are primarily in Australia, New Zealand, Southern Africa and South East Asia. BP is growing in China through two strategic alliances. BP's alliance with Petrochina in Guangdong Province in the coastal region of China had 201 stations at December 31, 2001, 105 of which BP reports as its share of the joint venture. BP has agreed in principle with Sinopec to form a second alliance through a joint venture to acquire, revamp or build 500 fuels service stations in the Zhejang Province, east China. The dual-branded service stations will sell gasoline produced by Sinopec and sell other petroleum products supplied by each partner. The Sinopec joint venture is expected to start development of sites in 2002. In addition, BP has 112 stations in Venezuela and 15 stations in Mexico. BP has agreed to sell its 21 service stations in Japan to Japan Energy with the sale expected to be completed in the first half of 2002. BP's exit from retail marketing in Japan is not expected to have any impact on its other business activities there.

Commercial and Industrial

In our Commercial and Industrial business we aim to attract more customers through innovation in multi-product offers and cleaner fuels, packaged with a range of value-added services and solutions, thus aiming to increase customer spend and growth in volumes at above the rate of market growth. For example, our offer to Commercial and Industrial customers has expanded to include BP's flexible pricing mechanism complete with a range of clean fuels and energy saving lubricants. Our Commercial and Industrial business operates in Australasia, Europe, Southern Africa and the USA. In 2001, BP restructured its small volume domestic and commercial fuels business exiting some markets and consolidating operations in other markets.

Our aviation business sells jet and other aviation fuels to airlines and general aviation customers as well as providing technical services to airlines and airports. During the last few years, our aviation business has strengthened its position in established markets and pursued opportunities in new or emerging markets. The business now markets in approximately 95 countries and is the third largest jet fuel supplier globally. The effect of the events of September 11, 2001 has been a reduction in aviation sales volumes.

Lubricants

We manufacture and market lubricant products and also supply related products and services to business customers and end-consumers in over 60 countries directly, and to the rest of the world through local distributors. Our business is concentrated on the higher value sectors of automotive lubricants, especially in the consumer sector, but also has a strong presence in commercial sectors such as marine and specialized industrial segments.

BP markets through its two major brands, Castrol and BP, and several secondary brands including Duckhams and Veedol. The Veba acquisition will increase our lubricants position in Central Europe as the Aral brand is integrated into the BP Lubricants organization.

Our lubricants business is organized by market segment. The main characteristics of each part of the business are as follows:

Consumer markets: We supply lubricants, other products and related business services to intermediate customers (for example retailers, workshops) who in turn serve end-consumers (car, motorcycle, leisure craft owners) in the mature markets of Europe and North America and also in the fast growing markets of the developing world (Asia, India, Middle East, South America and Africa). The Castrol brand is recognized worldwide and we believe it provides us with a significant competitive advantage.

Commercial vehicle and general industrial markets: We supply lubricants and lubricant related services to automotive manufacturers and other industrial customers.

Marine market: We supply lubricants and fuels, on a global basis, to major shipping companies as well as to small fishing vessel operators. We are the leading global participant in the marine lubricants market and operate a network of offices and supply points in more than 900 ports across 90 countries. During 2000, we formed an innovative global strategic partnership 'Marine Alliance' with Unitor, a major supplier of marine consumables, to supply a full range of products and services to marine customers. This partnership is targeting market growth through supplying an expanded range of products and services.

Specialist industrial market: We supply metalworking fluids and lubricants alongside a range of business services, such as fluid management, to the metal component manufacturing sector. We also have a significant high performance industrial lubricants business in some key markets.

Supply and Trading

We are one of the world's major traders of crude oil and refined products, dealing extensively in physical and futures markets. Our portfolio of purchases and sales is spread among spot, term, exchange and other arrangements, and covers a range of sources and customers to match the location and quality requirements of the Group's refineries and the various markets, while seeking to ensure flexibility and cost-competitiveness. In addition, the Group's oil-trading division undertakes trading in physical and paper markets in order to contribute to the Group's income.

Transportation

Our Refining and Marketing business owns, operates or has an interest in extensive transportation facilities for crude oil, refined products and petrochemical feedstocks in the US. It also has interests in a number of crude oil and product pipelines in the UK and the Rest of Europe.

We transport crude oil to our refineries principally by ship and through pipelines from our import terminals. We have interests in seven major crude oil pipelines in the UK and the Rest of Europe and sixteen in the USA.

Bulk products are transported between refineries and storage terminals by pipeline, ship, barge, and rail. Onward delivery to customers is primarily by road. We have interests in nine major product pipelines in the UK and the Rest of Europe and six in the USA.

During 2001 BP sold several transportation assets directly connected with BP refineries that had been divested including the products pipelines associated with the Alliance, Louisiana refinery, the products and crude lines associated with the Mandan, North Dakota refinery, and BP's 43.75% interest in the Frontier Pipeline crude oil pipeline associated with the Salt Lake City, Utah refinery.

BP also sold its 26.5% interest in the Pacific Pipeline in June 2001, and in March 2002 sold its interests in three Rocky Mountain pipelines.

Shipping

BP Shipping owns or operates an international fleet of crude and product tankers and LNG carriers carrying cargoes for the Group and for third parties. It also offers a wide range of services to Group and third party marine customers.

At December 31, 2001 the Group controlled or operated an international fleet of five Product Carriers, totalling approximately 0.19 million deadweight tons (dwt). Excluding BP companies in the USA, the Group had fourteen crude oil tankers (six Very Large Crude Carriers (VLCCs), and eight Medium Crude Carriers) totaling approximately 2.88 million dwt.

It also had an interest in six LNG carriers which are dedicated to transportation of Australian North West Shelf natural gas.

BP Companies in the USA had 19 tankers (ten Large Crude Carriers, four Medium Crude Carriers and five Product Carriers), totalling approximately 1.84 million dwt on long-term charter. BP owns four barges totalling 0.1 million dwt and has four vessels under construction totalling 0.64 million dwt.

In addition, a large number of small vessels are used by Group companies around the world.

46

CHEMICALS

Our Chemicals business is a major producer of petrochemicals through subsidiaries, joint ventures and associated undertakings. BP has operations principally in the USA and Europe. We are increasing our activities in the Asia-Pacific region. Chemicals is also responsible for the supply, marketing and distribution of chemical products to bulk, wholesale and retail customers.

	Years ended December 31,		
	2001	2000	1999
		($ million)	

Turnover (a)	11,515	11,247	9,392
Total replacement cost operating profit	128	760	686
Total assets	15,098	13,674	13,021
Capital expenditure and acquisitions	1,926	1,585	1,215
		($/tonne)	
Chemicals Indicator Margin (b)	108(c)	126 (d)	114

(a) Excludes BP's share of joint venture turnover of $102 million in 2001, $67 million in 2000, and nil in 1999.

(b) The Chemicals Indicator Margin (CIM) is a weighted average of externally based product margins. It is based on market data collected by Chem Systems in their quarterly market analyses, then weighted based on BP's product portfolio. While it does not cover our entire portfolio, it includes a broad range of products. Among the products and businesses covered in the CIM are the olefins and derivatives, the aromatics and derivatives, linear alpha olefins, acetic acid, vinyl acetate monomers and nitriles. Not included are fabrics and fibers, plastic fabrications, poly-alpha olefins, anhydrides, engineering polymers and carbon fibres, speciality intermediates, and the remaining parts of the solvents and acetyls businesses.

(c) Provisional. The data for the current year is based on eleven months of actual data and one month of provisional data.

(d) Restated following review of product margins with Chem Systems.

Chemicals margins are subject to industry cyclicality. The external drivers of our results in 2001 were determined by market demand levels, new industry supply starting up, pressures on feedstock prices, portfolio restructuring and business combination activity. In 2002, the chemical industry's external environment is expected to continue to see margins under pressure.

Our strategy is to create competitive advantage in petrochemicals through adding value to Group hydrocarbons, industry cost leadership, world-leading technology, strong market positions, and a bias to high growth products.

The Chemicals portfolio comprises three main sectors:

Aromatics and Derivatives. This sector comprises the production and conversion of Aromatics (Xylenes) into Purified Isophthalic Acid (PIA) and Purified Terephthalic Acid (PTA). PIA and PTA are chemical intermediates that are used in the production of fibres, containers, films and coatings.

Olefins and Polymers. The Olefins sector covers the production of the basic building blocks of chemical intermediates, such as ethylene and propylene. These are used in our polymers businesses to produce a wide range of polymers for commonly used products such as packaging, coatings, lubricants and detergents.

Intermediates. This business sector adds value to raw materials produced by our other chemicals activities and includes acetic acid and other derivatives. Intermediates are used by the automotive, construction, engineering plastics and resins, consumer goods and packaging industries.

Management of the portfolio is underpinned by five strategic tenets:

Adding value to BP Group hydrocarbons. As the petrochemicals arm of an oil major, we believe this is a key element of our competitive advantage, notably by allowing us to combine feedstock, refining and chemical processing across large integrated sites/systems.

Industry cost leadership. Continuing competitive pressures in the chemicals industry require an enduring focus on cost reduction and we have made cost management an important ongoing part of our business. We plan to continue to reduce underlying costs in 2002 through a number of targeted actions, such as achieving lower unit cost procurement, higher efficiency in our conversion processes and utilizing new technology applications. We also intend to continue to manage costs structurally by focusing our investment on a limited number of world-class manufacturing sites. By limiting the number of sites, we benefit from increased economies of scale and integration of chemical operations along the various value chains associated with our portfolio.

World leading technology. We believe technology will continue to distinguish the most successful companies from their competitors. Leading technology makes us a preferred supplier and a preferred joint venture partner. We intend to maintain and extend our leadership in the fundamental technologies that underpin our core businesses. BP already has a number of leading technologies in operation and is currently investing in production capacity, utilizing recent breakthroughs in butanediol, vinyl acetate monomer and ethyl acetate manufacture.

Strong market positions. This can be measured in a number of ways, such as market share, growth potential or performance in terms of returns. We have global leadership in paraxylene (PX), PTA, acetic acid, acrylonitrile, trimellitic anhydride (TMA) and a number of other products. We have also instituted a programme of marketing initiatives to improve our commercial capability. The programme includes developments in e-commerce, including the introduction of web-based marketing channels.

Bias to higher growth products. The majority of the BP portfolio is in market sectors that have historically grown more rapidly than the industry average.

We will therefore continue to focus our portfolio by investing in areas offering a good fit and divesting where there is insufficient alignment with the strategic tenets described above.

During 2001, we implemented or announced a number of structural changes that should significantly strengthen our position as the petrochemicals arm of an integrated energy company. The most significant structural changes were as follows:

-- In May 2001 we acquired from Bayer the 50% of Erdoelchemie we did not already own.

-- In November 2001 we finalized a transaction with Solvay, aimed at strengthening our polymers businesses in both Europe and the United States. Solvay has transferred its US and European polypropylene businesses to BP. The two companies have combined their European and US high-density polyethylene (HDPE) businesses to form BP Solvay Polyethylene Europe (BP share 50%) and BP Solvay Polyethylene North America (BP share 49%), respectively. In addition, BP has transferred its engineering polymers business to Solvay.

-- In February 2002 BP acquired a majority stake in Veba Oil, based in Germany. Veba's petrochemicals business, based at Gelsenkirchen and

Munchmunster, with net ethylene capacity of 0.7 million tonnes per year, will help meet BP's future chemical feedstock needs in the region.

We intend to divest the Fabrications, Fabrics and Fibers, and Burmah Castrol Chemicals businesses when the external environment is favourable as these businesses do not satisfy the five strategic tenets described above.

Manufacturing Facilities

BP has large-scale manufacturing facilities in Europe and the USA. The Group's major sites, with our share of their capacities are: Grangemouth (2,851 kilotonnes per annum (ktepa)) and Hull (1,615 ktepa) in the UK; Lavera (1,825 ktepa) in France; Marl (628 ktepa) and Koln (4,276 ktepa) in Germany; Geel (2,075 ktepa) in Belgium; and Texas City, Texas (2,654 ktepa), Chocolate Bayou, Texas (3,285 ktepa), Decatur, Alabama (2,176 ktepa), and Cooper River, South Carolina (1,332 ktepa) in the USA.

We also aim to grow in the Asia-Pacific region, which offers prospects for demand growth. The intention is to build further on the positions that the Group now holds in the region through planned investment and commercial relationships, such as joint ventures. Our share of capacity in Asia amounts to about 3,000 ktepa as follows: Indonesia (550 ktepa), Korea (828 ktepa), Malaysia (1,291 ktepa), Taiwan (663 ktepa), China (107 ktepa), Philippines (60 ktepa) and Japan (43 ktepa).

Production by region (a)	Years ended December 31, 2001	2000	1999
	(thousand tonnes)		
UK	3,125	3,137	3,737
Rest of Europe	7,925	6,713	5,993
USA	8,943	9,874	9,917
Rest of World	2,723	2,341	2,206
Total production	22,716	22,065	21,853

(a) Includes BP share of joint ventures, associated undertakings and other interests in production.

The following table shows BP production capacity by major products and by product group at December 31,2001.

Intermediates

	Aromatics and Derivatives	Olefins and Polymers	and Fabrications	Tota
	(thousand tonnes per annum)			
Purified terephthalic acid............	5,594	--	--	5,59
Ethylene..............................	--	4,004	--	4,00
Paraxylene............................	2,702	--	--	2,70
Polypropylene.........................	--	3,091	--	3,09
Styrenics.............................	--	1,538	--	1,53
Polyethylene..........................	--	2,483	--	2,48
Acetic acid/anhydride.................	--	--	2,260	2,26
Linear/poly alpha-olefins.............	--	--	1,280	1,28
Acrylonitrile.........................	--	--	949	94
Other	151	3,281	4,534	7,96
Total production capacity (a)	8,447	14,397	9,023	31,86

(a) Includes BP share of joint ventures, associated undertakings and other interests in production.

The production capacity increase from 2000 of approximately 5,000 ktepa resulted from our acquisition of the 50% share of Erdoelchemie, the Solvay transaction and organic growth from new plants and de-bottlenecking.

BP's petrochemical products are sold to companies in a number of industries that manufacture components used in a wide range of applications. These include the agriculture, automotive, construction, furniture, household products, insulation, packaging, paint, pharmaceuticals and textile industries. Our products are marketed through a network of sales personnel and agents who also provide technical services.

Aromatics and Derivatives

The leading market positions of our key products give us access to a wide range of high-quality options, in terms of both investments and growth. We strive to be number one or two in terms of market share in the markets in which we compete, and we are currently a global leader in PTA and PX. Our strategy has been to bias our portfolio towards products that have been growing at a rate of approximately 8-10% per year. This is approximately three times the rate of global economic growth and compares with an estimated average of 4% for the petrochemicals industry as a whole.

Products

PTA is important as a raw material for the manufacture of polyester; PIA is used for isopolyester resins and gel coats; napthalene dicarboxylate (NDC) is used for photographic film and specialized packaging.

BP is the world's largest producer of PTA, with an interest in approximately 21% of the world's PTA capacity. PTA is manufactured at Cooper River, South Carolina and Decatur, Alabama, in the USA, Geel in Belgium, and Kuantan in Malaysia. We also produce PTA through Samsung Petrochemical Company (SPC) in Korea (BP 35%), China America Petrochemical Company (CAPCO) in Taiwan (BP 50%), PT Ami in Indonesia (BP 50%), Rhodiaco in Brazil (BP 49%) and TEMEX in Mexico (BP 8.55%). The site in Taiwan is the largest PTA production site in the world, followed by our Cooper River site, which is the second largest. These two, together with the Korean and Decatur sites, represent four of the five largest PTA production sites in the world.

PIA is produced in Joliet, Illinois; Geel, Belgium; and by the AGIC joint venture (BP 50%) with Mitsubishi Gas Chemical Company in Japan. NDC is produced at our plant in Decatur, Alabama.

BP is one of the world's largest producers of PX and metaxylene (MX), the feedstocks for PTA and PIA, respectively. PX and MX are produced from mixed xylene streams acquired from BP refineries and third party producers. The Aromatics and Derivatives business is largely integrated, using our manufactured PX as feedstock for the production of our PTA product.

Major Activities

-- Two new PTA plants are under construction in China and Taiwan, which will use BP's new PTA technology. The Zhuhai (BP 85%) unit in China should add 350-ktepa capacity. A new plant at our CAPCO joint venture in Taiwan (BP 50%) should add a further 700-ktepa capacity. The new Zhuhai and CAPCO units are both expected to commence operation in 2003.

-- Advanced manufacturing technology projects were completed at Texas City and Decatur during 2001. These initial projects are part of a broader plan to implement the introduction of leading edge process technology and control systems.

-- The de-bottlenecking of the PTA No. 3 unit at Geel was successfully completed, increasing capacity by 100 ktepa to 600 ktepa. This project had demonstrated the ability to stretch our in-house technology.

-- Options were developed for site and technology for the next European PTA investment (PTA No. 4). This is intended to be a world-scale development sited in northwestern Europe to take account of integration with customers and feedstock.

-- Joint efforts with Downstream resulted in a project to source PX feedstock from BP Group refineries. This project has the two aims of enabling northwestern European refineries to meet the increasingly strict gasoline aromatic content regulations and bringing feedstock supply for PX in house.

-- BP, in collaboration with several industry partners, has developed a polyethylene terephthalate (PET) beer bottle that is believed to be technically best in class and cost competitive with glass. Market evaluation and roll out is expected to occur in the first half of 2002. The vision is to establish PET as a competitive third packaging material in the global beer market, developing substantial new markets for BP's polyester intermediate product lines.

Olefins and Polymers

Our goal is to achieve a strong polymers market position. Through the dissolution of our Appryl joint venture we acquired operational control of a polypropylene plant at Grangemouth, UK. The Solvay deals increase our polypropylene business and our interests in global HDPE and the additional 50% share of Erdoelchemie (now called BP Cologne) represents an increase of some 10% of our total chemicals production volumes. The Veba acquisition further enhances our olefins production capability. In addition to these business-repositioning changes, we will continue to invest in our existing businesses. We aim to build on our existing technology base, which includes metallocene catalyst, the proprietary technology used in Innovene, our gas-phase polyethylene production process. Our product portfolio is biased to differentiated products, such as HDPE and polypropylene, which are further enhanced as a result of the Solvay transaction.

Products

We produce and market the basic petrochemical building blocks, known as feedstocks, that are used primarily as raw material for other chemical products. Feedstock chemicals are derived from the steam cracking of liquid and gaseous hydrocarbons. The olefins - ethylene, propylene and butadiene - are produced by crackers at Grangemouth, UK; Lavera, France (Naphtachimie - BP 50%); Cologne, Germany and Chocolate Bayou, Texas. Olefins are also manufactured by Ethylene Malaysia Sdn. Bhd. (BP 15%) at Kertih, Malaysia. Our production share of the Veba crackers at Gelsenkirchen and Munchmunster will be added during 2002. These crackers produce the raw materials for the production of derivative products including polyethylene, polypropylene, acrylonitrile, styrene, ethanol and ethylene oxide, which are also produced at various BP plants.

50

The polymers product line includes polypropylene, used for moulded products, fibres and films; polyethylene, used for packaging, pipes and containers; and styrene polymers, used in packaging and containers. We are the second-largest producer of polypropylene in the world. Polypropylene is manufactured at Chocolate Bayou, Deer Park and Cedar Bayou, Texas; Antwerp and Geel, Belgium; Sarralbe, France and at Carson City, California. In addition, BP operates a new polypropylene plant at Grangemouth, UK, commissioned during 2000, and from 2001 we have an interest in the manufacturing joint venture at Lavera, France. BP has its own proprietary polypropylene technology.

During 2001 BP gained clarification on the license to operate with metallocene catalysts for its Innovene gas phase polyethylene process, following an agreement between BP and other interested parties. The combination of metallocene catalysts with the Innovene process produces differentiated polyethylene film products that have an improved balance of performance and processability compared to traditional metallocene or Ziegler-Natta based materials.

We are one of Europe's leading producers of polyethylene; the world's most widely used plastic. BP operates linear low-density polyethylene (LLDPE) plants at Grangemouth in the UK and Cologne in Germany. Cologne also produces low-density polyethylene (LDPE). We also produce LLDPE through PT Peni (BP 75%) at Merak, Indonesia and through Polyethylene Malaysia Sdn. Bhd. (BP 60%) at Kertih, Malaysia. BP Solvay Polyethylene Europe (BP 50%) has HDPE plants at Grangemouth, UK; Antwerp, Belgium; Sarralbe and Lavera, France; and Rosignano, Italy. In addition BP Solvay Polyethylene North America (BP 49%) has a HDPE plant at Deer Park, Texas.

We operate styrene monomer plants at Texas City, Texas in the USA and Marl in Germany. Polystyrene plants are operated at Marl and Wingles in France and Trelleborg in Sweden. Expanded polystyrene plants are operated at Wingles and Marl.

Major Activities

- A 270-ktepa ethylene expansion at Grangemouth was commissioned late in 2001. The expansion boosts Grangemouth's ethylene capacity to 1 million tonnes. This additional production will feed new derivative plants at both Grangemouth and Hull.
- BP completed the purchase of Bayer's 50% stake in Erdoelchemie (renamed BP Cologne) in May 2001.
- The transaction with Solvay has made BP the world's second largest producer of polyproylene (and the largest in North America) and positioned BP as the world's fourth-largest polyolefins producer. However, due to the current difficult business environment, we idled 205 ktepa of polypropylene capacity at Chocolate Bayou in the fourth quarter of 2001 and in March 2002 we announced its permanent closure. Also in March 2002 we announced the closure of our 261 ktepa polypropylene facility at Cedar Bayou.
- Restructuring programmes were begun at sites in Cologne, Lavera and Grangemouth to realize incremental integration value.
- The company announced its intention to shut down an older polyethylene production unit, Rigidex 2, within the Grangemouth chemicals site. BP also closed its LDPE manufacturing operations at Wilton on Teesside due to difficult market conditions.
- During 2001 the Chocolate Bayou and Texas City sites were integrated into a single management structure to increase standardization and take advantage of the overall scale and buying power of the combined BP chemicals and refining activities in south Houston.
- A major fire at Chocolate Bayou in February 2001 was managed safely and efficiently with operations restored by July and with minimal impact to customers or internal businesses. Record production volumes were achieved in October as operations became fully restored.
- Late in 2001 we increased our interest in the Carson City refinery polypropylene unit from 67% to 85%.
- In light of continuing difficult market conditions in the Philippines, BP is reassessing its involvement in the Bataan Polyethylene Co. plant (BP 39%).
- In December 2001 BP, Sinopec and SPC announced the formation of SECCO (BP 50%) which plans to build a $2.7 billion petrochemicals complex near Shanghai. The complex is expected to begin operation in 2005. In January 2002 we announced a loan agreement worth $1.8 billion with nine domestic and two international banks to fund two-thirds of the project.

Intermediates

As with Aromatics, we aim to be number one or two in terms of market share in markets where we compete. New investments will build on existing leadership positions and distinctive technology.

Products

The intermediate businesses add value to raw materials produced by our other chemicals businesses and include acetic acid and its derivatives; a range of solvents and industrial chemicals; linear alpha-olefins (LAOs); polybutenes; acrylonitrile; TMA, used by the automotive, construction, consumer goods, and packaging industries; butanediol (BDO), used in synthetic materials and engineering plastics; and maleic anhydride (MAN), used in a wide range of plastics and resins.

We are a major supplier of acetic acid, a versatile chemical used in a variety of products such as foodstuffs, textiles, paints, dyes and pharmaceuticals. BP has acetyls operations in Europe, the USA, in Korea through Samsung - BP Chemicals (BP 51%), in China through Yangtze River Acetyls Company (BP 51%) and in Malaysia through BP Petronas Acetyls Sdn. Bhd.(BP 70%)

In Korea, the Asian Acetyls Company (BP 34%) operates a 150-ktepa vinyl acetate monomer (VAM) plant. A new 250-ktepa VAM plant at Hull was commissioned during 2001 and the VAM plant at Baglan Bay in Wales is due to close during 2002.

BP is a leading supplier of polybutene which we manufacture at Whiting, Indiana and at Lavera, France. A plant at Texas City, Texas is due to cease production in 2002. Polybutene is used in fuel additives, lubricants, adhesives, sealants, cable filling compounds, personal care products, tackified polyethylene, explosives and many other products.

LAOs are used in the production of polyethylene, for the manufacture of plasticizers for polyvinyl chloride, for the manufacture of poly alpha-olefins for synthetic lubricants, for the production of biodegradable surfactants, in synthetic-based drilling muds for the oil field and for a host of other intermediate and final products. LAOs are produced at our facilities in Pasadena, Texas; Joffre, Alberta and Feluy, Belgium.

BP is a leading supplier of poly alpha-olefins, high viscosity index materials primarily used in the production of high performance, environmentally friendly, synthetic lubricants and motor oils. These materials are manufactured at our facilities in Deer Park, Texas and Feluy, Belgium.

BP is the world's largest producer and marketer of acrylonitrile. We operate two acrylonitrile plants at Green Lake, Texas and Lima, Ohio. Green Lake, with a capacity of 460 ktepa, is the largest acrylonitrile production site in the world. Acrylonitrile is also produced at Cologne, Germany and through a capacity rights agreement with Sterling Chemicals at Texas City, Texas. Additionally, BP is the world's largest producer and marketer of acetonitrile, primarily sold into pharmaceutical applications.

The anhydride business unit produces TMA and MAN at Joliet, Illinois, and is the world's largest producer of TMA. In 2000, we entered the global market for BDO using our proprietary technology in a world-scale plant at Lima, Ohio. BDO and its derivatives are used in pharmaceuticals, a variety of personal care products, plastics, auto parts and sports clothing.

Major Activities

-- The new 220-ktepa ethyl acetate plant at Hull was commissioned successfully in June 2001. The 110-ktepa ethanol plant at Grangemouth is nearing mechanical completion and is due to start up during 2002. The ethyl acetate investment is based on BP's innovative 'direct addition' method, which uses ethylene and acetic acid and does not require ethanol as a raw material. To supply ethylene to the new plants a pipeline has been installed between Teesside and Hull, linking into the UK ethylene network.

-- First production was achieved from a new 250-ktepa VAM plant at Hull late in 2001. The plant uses the proprietary BP LEAP technology based on a fluid bed catalyst. The plant will replace production from Baglan Bay and the Enichem toll manufacturing agreement at Porto Marghera. The capacity of the new plant is planned to increase to 300 ktepa.

-- We completed construction of a 250-ktepa LAO facility at Joffre in Alberta, Canada. The plant started up in the fourth quarter of 2001 and is operating smoothly.

-- During 2001, both the phthalic anhydride and phthalates plants at Hull were closed. These units are being demolished during 2002. Late in 2001, we announced the closure of the S24 Acetate plant at Hull. The plant, which manufactured 175 ktepa of ethyl acetate, iso-propyl acetate and butyl acetate closed at the end of 2001. Also during the fourth quarter of 2001 we announced the sale of our butyl acetate business to Ineos. The sale will include the transfer of the 60-ktepa plant at Antwerp.

-- We announced the cessation of the production of alcohols on our site at Pasadena, Texas. The 60-ktepa plant will stop during the fourth quarter 2002 when this site will concentrate on the production of LAOs.

-- The proposed 65-ktepa TMA plant at our existing PTA complex in Kuantan, Malaysia has advanced to construction bid stage. As a consequence of current market conditions, this TMA plant construction has been temporarily suspended.

OTHER BUSINESSES AND CORPORATE

Other Businesses and Corporate comprises Finance, BP Solar, the Group's coal asset and aluminium asset, its investments in PetroChina and Sinopec, interest income and costs relating to corporate activities worldwide.

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Turnover	783	249	198
Total replacement cost operating loss	(556)	(1,110)	(826)
Total assets	8,073	11,970	2,643
Capital expenditure and acquisitions (a)	563	30,616	284

(a) Capital expenditure and acquisitions in 2000 includes $27,506 million for the acquisition of ARCO and $994 million for the acquisition of interests in PetroChina and Sinopec.

Finance co-ordinates the management of the Group's major financial assets and liabilities. From locations in the UK, Europe, the USA and the Asia-Pacific region, it provides the link between BP and the international financial markets, and makes available a range of financial services to the Group including supporting the financing of BP's projects around the world.

Moody's and Standard and Poor's have assigned long-term debt ratings to BP of Aa1 and AA+, respectively.

Finance has in place a European Debt Issuance Programme (DIP) and a US Shelf Registration under each of which the Group may raise an aggregate of $6 billion of debt for maturities of one month or longer. At March 26, 2002, the amount drawn down against the DIP was $564 million, and $1,500 million against the US Shelf Registration.

BP Solar. Our solar energy business increased production and shipments by 30% compared with 2000, selling a total of 55 megawatts (MW) of solar panel generating capacity (2000, 42 MW). Major projects in 2001 included the purchase of a new Madrid facility that will be one of the world's largest solar plants when the production facility upgrade is completed in late 2002, and the completion of a $48 million project to power 150 Philippine villages - the largest solar energy project to date.

Coal activity consists of our 50% interest in PT Kaltim Prima Coal, an Indonesian company. This company operates an opencast coal mine at Sangatta in Kalimantan, Indonesia.

Aluminium. Our aluminium business is a non-integrated producer and marketer of rolled aluminium products, headquartered in Louisville, Kentucky, USA. Production facilities are located in Logan County, Kentucky and are jointly owned with Alcan Aluminum. The primary activity of our aluminium business is the supply of aluminium coil to the beverage can business.

Investments in China. During 2000 BP made two strategic investments in China, one of the world's fastest growing economies. BP invested $416 million in the China Petroleum and Chemical Corporation (Sinopec) and $578 million in PetroChina in the initial public offerings of both companies. BP has a 2.2% interest in each company. Separately, BP announced plans to form joint ventures with both companies: in natural gas marketing and fuels retailing with PetroChina and in fuels and petroleum products marketing and chemicals with Sinopec. PetroChina and Sinopec are two of China's major companies in the oil and chemicals businesses.

Research, technology and engineering activities are carried out by each of the major business streams on the basis of a distributed programme coordinated by the BP Technology Council. This body provides leadership for scientific, technical and engineering activities throughout the Group and in particular promotes cross-business initiatives and the transfer of best practice between businesses. In addition, a group of eminent industrialists and academics form the Technology Advisory Council, which advises senior management on the state of technology within the Group and helps identify current trends and future developments in technology.

Research and development is carried out using a balance of internal and external resources. Involving third parties in the various steps of technology development and application enables a wider range of technology solutions to be considered and implemented, improving the productivity of research and development activities.

The innovative application of technology and the rapid transfer of this knowledge through the Group make a key contribution to improving BP's business performance, particularly in the areas of the introduction of new products, safety, the environment, cost reduction and efficiency of business operations. We believe that, in addition to improving existing business performance, the use of innovative technology can create new possibilities for the organic growth of our energy- and petrochemical-related businesses.

Renewables and alternative fuels. In renewables we are further building expertise in wind energy with plans to construct a wind farm at our jointly owned Nerefco refinery in the Netherlands. We are exploring market opportunities for hydrogen and fuel cells through participation in various industry projects and organizations promoting fuel cells and hydrogen fuels. Examples include a joint project with DaimlerChrysler, First Bus, Transport for London and the Energy Savings Trust to introduce three hydrogen fuel cell buses to England's capital; and BP and Singapore's Economic Development Board (EDB) have signed a letter of intent to build hydrogen refueling stations for future Singapore motorists.

Insurance. The Group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. This is because external insurance is not considered an economic means of financing losses for the Group. Losses will therefore be borne as they arise, rather than being spread over time through insurance premia with attendant transaction costs. The position is reviewed periodically.

Integrated supply and trading. During 2001, BP brought together the trading activities in Gas and Power, Refining and Marketing and Finance under single leadership. As Chemicals develops trading activities, they will be included as well. The financial results of the trading activities will remain with the business streams. This change provides the opportunity to improve our knowledge transfer, risk management, control and assurance processes and to optimize our systems investment.

REGULATION OF THE GROUP'S BUSINESS

United Kingdom

Licensing. Pursuant to, among other things, The Petroleum Act 1998, all petroleum existing in its natural condition in strata in the UK or beneath its territorial waters (including its continental shelf) is the property of the Crown, and licences to explore for and produce it may be granted, subject to conditions, by the Secretary of State for Trade and Industry (Secretary of State). These conditions include provisions relating to the term of the licence, the imposition of specific drilling obligations, environmental protection controls, controls over the development and decommissioning of oil and natural gas fields (including restrictions on production) and the payment of royalties.

Development of oil and natural gas reserves. The development and production of UK oil and natural gas reserves (including rates of production) require the approval or consent of the Secretary of State. There have been a number of policy statements by various UK Governments over the years with respect to production controls. Although successive Governments have made it clear that the imposition of production cut-backs in order to facilitate a coherent depletion policy has been kept under review, the steps taken by the Government since the early 1980s have tended to concentrate on encouraging exploration, development and production and no significant cut-backs of previously agreed rates of production are known to have been imposed.

Other controls. In addition to the regulatory powers of the Government referred to above, the Secretary of State has wide powers over the oil field operations, including gas flaring, the installation, use and tariffs of sub-marine pipelines, the construction or expansion of refining capacity and powers to impose programmes for the eventual decommissioning of offshore installations. Furthermore, the Secretary of State for Transport has powers to control the positioning of offshore installations if the chosen location is in or is close to a shipping lane. The UK Health and Safety Executive has wide powers and duties in relation to offshore health and safety. BP is also subject to European Union legislation, in particular the Procurement Directive which regulates the procedure for awarding major contracts.

Petroleum revenue tax. Petroleum revenue tax (PRT) was abolished in the Finance Act 1993 in respect of oil and natural gas fields given development consent on or after March 16, 1993 (Non-Taxable Fields). Profits from Non-Taxable Fields are charged to corporation tax under general principles. PRT is still charged on profits from fields given development consent before that date (Taxable Fields). PRT is charged in relation to Taxable Fields on profits from oil (which includes natural gas except where specifically excluded by statute) won under licences granted under either the Petroleum (Production) Act 1934 or the Petroleum (Production) Act (Northern Ireland) 1964. It is charged on a field-by-field basis, at the rate of 50% for chargeable periods ending after June 30, 1993 (75% for periods ending on or before that date), on the assessable profit arising in each chargeable period (normally the six months ending on June 30 and December 31 in each year), as reduced by any allowable losses and by an oil allowance (unless the maximum amount of oil allowance has already been used), and subject in certain years to an overall limit (safeguard). PRT is also chargeable on any consideration received in connection with the use by other fields and the disposal of certain 'qualifying assets', the expenditure on which is allowable for PRT, subject to an allowance in the case of the use of assets by fields which are themselves liable to PRT.

The assessable profit reflects, very broadly, the market value of oil won less the costs of discovery and production, including any Government royalties payable. Interest and other financing costs are not deductible in determining the assessable profit; instead, certain costs are designated as qualifying for a supplement of 35% (uplift). Uplift ceases for costs incurred after the end of the chargeable period in which the field's cumulative income exceeds its cumulative expenditure (payback).

Oil allowance exempts certain amounts from PRT. For each onshore field and offshore field given development consent before April 1982, an allowance of up to 250,000 tonnes of oil per chargeable period is available, subject to a cumulative total of 5 million tonnes. For each onshore field and each offshore field situated in the Southern Basin of the North Sea given development consent after March 1982, the oil allowance for chargeable periods ending after June 30, 1988 is 125,000 tonnes per chargeable period and the cumulative total is 2.5 million tonnes. For each offshore field not situated in the Southern Basin given development consent after March 1982, the allowance is 500,000 tonnes per chargeable period subject to a cumulative total of 10 million tonnes. The oil allowance is shared by the participants in each field in proportion to their shares of oil. Safeguard provides that the total PRT payable in respect of a field is limited to 80% of the amount (if any) by which the PRT profits for a chargeable period (specially adjusted for this purpose) exceed 15% of accumulated expenditure (as adjusted). Safeguard remains available after payback has been reached for half as many periods again as it took to reach payback from the first chargeable period.

Allowable losses in any chargeable period can be set off against the assessable profits of subsequent or, after making an appropriate claim, previous periods from the same field but, in relation to losses arising in respect of chargeable periods ending after June 30, 1993, the PRT repayment plus any interest thereon arising from the set-off of losses against profits of previous periods cannot exceed 60% of the losses set off (85% in respect of chargeable periods ending after June 30, 1991 and on or before June 30, 1993). In addition, relief is available against the assessable profit from a field for certain expenditure incurred outside the field. There are restrictions to prevent the obtaining of relief for expenditure incurred in connection with Non-Taxable Fields against profits from Taxable Fields. Exploration or appraisal expenditure incurred on or after March 16, 1983 and before March 16, 1993, in respect of an area for which no development decision has been made, may be set against the assessable profits of any Taxable Field together with any such expenditure incurred prior to that date which is designated as abortive. There is no relief for exploration and appraisal incurred after March 16, 1993 unless the Company was already committed to it at that date and it is incurred on or before March 16, 1995. There is an additional transitional relief for exploration and appraisal expenditure, subject to certain conditions, limited to a maximum of (pound)10 million for expenditure incurred on or after March 16, 1993 and before January 1, 1995. Finally, a loss from a Taxable Field in which the winning of oil has permanently ceased which cannot be relieved against the assessable profits of that field can be claimed against the assessable profit from any other Taxable Field. The offset of reliefs is limited to prevent a company buying into mature oil fields and setting pre-acquisition expenditures against the assessable profits of that field.

Royalties. Royalty is charged on the value of production from certain licences, in most cases payable at a rate of 12.5%. Royalty has been abolished for fields which received development consent after March 31, 1982. Production licences contain provision for Royalty to be charged and separate rules (called modes) will apply dependant on where the licence is located and when it was issued. There are seven separate modes for calculating Royalty. Royalty is calculated by reference to six month chargeable periods (CP) ending on June 30, and December 31, with a return and payment made two months after the end of the CP. Certain modes provide for relief of conveying and treating expenditure. The relief varies considerably depending upon which mode applies. Some modes provide no relief for expenditure.

Corporation tax. Companies are also subject to corporation tax on their profits or gains from oil extraction activities, although PRT is deductible in computing any corporation tax liability. There are restrictions on using reliefs from other activities against profits or gains from oil extraction activities, or from the disposal of interests in oil or of assets used in connection with a field in the UK or a designated area. There is also an exemption from capital gains taxation and capital allowance clawback for certain exchanges of licence interests before the development stage. An election can be made in relation to expenditure incurred after June 30, 1991 for 100% reliefs for certain net offshore decommissioning expenditure. Losses created by these decommissioning reliefs are available for set-off against profits of the previous three years.

United States

Tax. The State of Alaska imposes various taxes on the Group's operations in Alaska. At present, these include a severance tax on oil and natural gas produced, an ad valorem tax on all oil and gas exploration, production and pipeline equipment and a corporate income tax on companies doing business in Alaska. Following the Exxon Valdez oil spill, the State of Alaska passed an act to finance the State's Oil and Hazardous Substance Release Response Fund by imposing a conservation surcharge of $0.05 per barrel on all oil subject to the State's oil and gas properties production tax. Subsequently, the State amended the surcharge to suspend $0.02 per barrel of it when the balance in the Response Fund exceeds $50 million, and as a result the net surcharge is $0.03 per taxable barrel unless there is a spill that draws the Fund's balance below $50 million. Further, losses occurring in connection with a catastrophic oil discharge are not deductible as business expenses in determining the gross value of oil for tax purposes in the State of Alaska.

Pipeline regulations. The Interstate Commerce Act requires common carriers engaged in the transport by pipeline of oil in interstate or foreign commerce to file tariffs with the Federal Energy Regulatory Commission (FERC) showing all rates, classifications, rules and practices between all points on their system. It also prohibits them from collecting any different compensation for transportation from that specified in their approved tariffs. Third parties, or the FERC on its own motion, may initiate an investigation of any proposed tariff, which involves the scheduling of a hearing. If the FERC, at the conclusion of a hearing, finds that a new or increased rate is unreasonable or discriminatory, or otherwise in violation of the Interstate Commerce Act, it may order the carrier to cease and desist from charging that rate, may prescribe a rate for the future and order refunds to shippers of collected amounts found to be unreasonable. Similar corresponding provisions at a state legislative level and enforced through a state regulator may also apply to common carriers engaged in the transport by pipeline of oil in intrastate commerce.

ENVIRONMENTAL PROTECTION

Health, Safety and Environmental Regulation

The Group is subject to numerous national and local environmental laws and regulations concerning its products, operations and activities. Current and proposed fuel and product specifications under a number of environmental laws will have a significant effect on the production, sale and profitability of many of our products. Environmental laws and regulations also require the Group to remediate or otherwise redress the effects on the environment of prior disposal or release of chemicals or petroleum substances by the Group or other parties. Such contingencies may exist for various sites including refineries, chemicals plants, natural gas processing plants, oil fields, service stations, terminals and waste disposal sites. In addition, the Group may have obligations relating to prior asset sales or closed facilities. Provisions for environmental restoration and remediation are made when a clean-up is probable and the amount is reasonably determinable. Generally, their timing coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites. The provisions made are considered by management to be sufficient for known requirements.

The extent and cost of future environmental restoration, remediation and abatement programmes are often inherently difficult to estimate. They depend on the magnitude of any possible contamination, the timing and extent of the corrective actions required and BP's share of liability relative to that of other solvent responsible parties. Though the costs of future restoration and remediation could be significant, and may be material to the results of operations in the period in which they are recognized, it is not expected that such costs will have a material impact on the Group's overall financial position or liquidity.

The Group's operations are also subject to environmental and common law claims for personal injury and property damage caused by the release of chemicals, hazardous materials or petroleum substances by the Group or others. Proceedings instituted by governmental authorities are pending or known to be contemplated against BP and certain of its US subsidiaries under US federal, state or local environmental laws, each of which could result in monetary sanctions in excess of $100,000. No individual proceeding is, nor are the proceedings as a group, expected to have a material adverse effect on BP's consolidated financial position or profitability.

Management cannot predict future developments, such as increasingly strict requirements of environmental laws and enforcement policies thereunder, that might affect the Group's operations or affect the exploration for new reserves or the products sold by the Group. A risk of increased environmental costs and impacts is inherent in particular operations and products of the Group and there can be no assurance that material liabilities and costs will not be incurred in the future. In general, the Group does not expect that it will be affected differently from other companies with comparable assets engaged in similar businesses. Management believes that the Group's activities are in compliance in all material respects with applicable environmental laws and regulations.

For a discussion of the Group's environmental expenditures see Item 5 -- Operating and Financial Review and Prospects -- Environmental Expenditure.

Kyoto Protocol

In December 1997, at the Third Conference of the Parties to the United Nations Framework Convention on Climate Change in Kyoto, Japan, the participants agreed on a system of differentiated internationally legally binding targets for the first commitment period of 2008-2012. The range of targets in Annex I countries (OECD, former Soviet Union and Eastern Bloc countries) against 1990 levels of emissions is from -8% to +10% for a basket of the six main greenhouse gases. The USA agreed, subject to ratification by the Senate, on a reduction of 7%, and the European Union on a reduction of 8%. EU member states have undertaken differentiated commitments on the basis of 'burden sharing' to meet the overall Community target. If these targets are to be met, some reduction in the use of fossil fuels would be required within countries which have ratified the Kyoto treaty, although a portion of the reduction in emissions will be delivered by switching to lower carbon fuels (for example natural gas). The impact of the Kyoto agreements on global energy (and fossil fuel) demand is expected to be small (see International Energy Agency Global Energy Outlook, 2000 Edition).

At the Seventh Conference of the Parties to the United Nations Framework Convention on Climate Change, held in Marrakech in November 2001, broad agreement was reached on many of the outstanding issues with the Kyoto Protocol. In order to achieve this, a number of concessions were made. The result is that if implemented, the agreement will be likely to lead to approximately a 1.5% reduction in greenhouse gas emissions in total across those countries expected to participate. Overall, global emissions will continue to increase, as the energy demand of the developing nations continues to increase strongly. It is therefore likely that, in the medium term, the global demand for fossil fuels will increase, with gas taking the largest share of that growth.

Legislation and Regulation

The following is a summary of significant health, safety and environmental legislation affecting the Group in 2001.

United States

The Clean Air Act and its regulations require, among other things, new fuel specifications and sulphur reductions, enhanced monitoring of major sources of specified pollutants; stringent air emission limits on chemical plant, refinery, marine and distribution terminals; and risk management plans for storage of hazardous substances.

Title V of the Clean Air Act requires major emission sources to obtain new air permits. This permitting effort is underway at the Group's US operations. Title V also requires more comprehensive measurement of specified air pollutants from major emission sources. Two aims of this regulation are to provide regulating bodies with accurate data on emissions from major sources, and to enable regulatory authorities to better evaluate compliance with applicable emission limitations.

The Risk Management Plan regulations under the Clean Air Act require that any non-exempted facility that processes or stores a threshold amount of a regulated substance prepares and implements a risk management plan to detect, prevent and minimize accidental releases. The primary components of the programme require undertaking an offsite hazard assessment, preparing a response plan and dialogue with the local community.

Additionally, the Clean Air Act imposes specifications for motor vehicle fuels that significantly impact petroleum refining, transportation and marketing operations. In nine urban areas with the highest ozone levels, reformulated gasoline (RFG) containing oxygenates, lower levels of benzene, lower volatility and reduced nitrogen oxides emissions was introduced beginning January 1995. The levels of volatility and nitrogen oxides emissions standards were tightened again in January 2000, with the introduction of Phase II RFG. BP manufactures and markets fuels in some of these nine areas, as well as in other areas that chose to join the RFG programme.

Since 1992, gasoline sold during the winter in approximately 40 metropolitan areas with higher carbon monoxide levels must have higher levels of oxygenates such as methyl-tertiary-butyl-ether (MTBE) and ethanol. BP is providing such oxygenated fuels in a number of US markets. Recently some environmental groups and legislators have expressed opposition to the continued use of MTBE as an oxygenate. California has recently announced a ban on the use of MTBE, effective January 2003, due to groundwater contamination and public health concerns. Other states and the US Congress have either passed or are considering legislation to restrict or eliminate the use of MTBE. Some metropolitan areas have been able to achieve compliance with carbon monoxide standards and terminate their wintertime oxygenated fuels programmes.

At the end of 1999, the US Environmental Protection Agency (EPA) promulgated its Tier 2/Gasoline Sulphur Programme. This programme will impose new tailpipe emission standards on all passenger vehicles while lowering the allowable gasoline sulphur content. The gasoline sulphur standards will be phased in from 2004 to 2006.

Beginning 1993, the Clean Air Act limited highway diesel fuel sulphur content to 500 parts per million. BP has been producing this fuel in many of its US markets. At the end of 2000, the EPA adopted rules reducing highway diesel sulphur limits to 15 parts per million. These rules will take effect in June 2006. The Act also requires service stations located in certain ozone non-attainment areas to install equipment to capture gasoline vapours released during refueling.

In 2001, EPA finalized new gasoline toxic emission baseline requirements, effective January 2002. This requires refiners to maintain current levels of over-compliance with toxic emissions performance standards that apply to RFG and anti-dumping standards that apply to conventional gasoline. Both the new gasoline and highway diesel rules will necessitate significant capital expenditures additions or upgrades to current refining facilities and may render some product lines or facilities uncompetitive.

The Clean Air Act also requires installation of 'maximum achievable control technology' (MACT) over a ten-year period at certain types of industrial facilities that release certain specified toxic chemicals. Additional controls could be required if the EPA determines that an unacceptable residual risk remains after installation of MACT. The EPA has finalized MACT control requirements for certain categories of chemical plants, refineries, gasoline marketing terminals and marine terminals. Additional regulations on some sources in petroleum refineries were proposed in 1998. These were expected to be finalized in 2001 but were deferred by the new Administration. They will likely be promulgated in 2002 with compliance required 3 years later. In order to comply with the National Ambient Air Quality Standards, which were promulgated to protect public health, some states will be requiring large reductions in the emission of nitrogen oxides. This will require the addition of significant new controls on some refineries and chemical operations in the US.

During 2001, BP entered into a consent decree with the EPA and several states that settled alleged violations of various Clean Air Act requirements at BP's refineries. This settlement, which largely addresses emissions of sulphur dioxide and nitrogen dioxide, requires the installation of additional controls at all of BP's US refineries at a cost, over at least an eight-year period, of approximately $500 million, and the payment of a $10 million penalty. The cost of installation of additional controls will be accounted for in line with BP's accounting policy for environmental expenditure. A one-time payment of the $10 million penalty was incurred in 2001.

BP is also in the third year of implementing a plea agreement with the US Justice Department to develop, implement and maintain a nationwide environmental management system (EMS) consistent with the best environmental practices at all Group facilities engaged in oil exploration, drilling and/or production in the US and its territories. This programme is expected to cost approximately $15 million.

The Clean Water Act regulates the discharge of wastewater and other pollutants into US waters. Facilities are required to obtain permits for most discharges, install control equipment and implement operational controls and preventative measures. Requirements under the Clean Water Act have become more stringent in recent years, including coverage of storm and surface water discharges at many facilities and increased control of toxic discharges.

During 1995 a final federal rule was issued regarding protection of the Great Lakes watershed which will have local and national impacts on water protection requirements. In July 2000, EPA promulgated a new rule that would impose total maximum daily limits (TMDLs) on discharges that would impair achievement of water quality objectives in many waterways. The US Congress did not provide EPA with funding to implement the rule, but work on TMDLs is ongoing under an earlier rule and new, more stringent limits on discharges from industrial facilities are expected to result. Many industries challenged EPA's new rule in court and in response, EPA deferred implementation of the rule while it reassessed its requirements.

The Oil Pollution Act of 1990 (the Oil Pollution Act or OPA 90) significantly increased oil spill prevention requirements, spill response planning obligations and spill liability for tank vessels (tankers and barges) transporting oil, offshore facilities (such as platforms) and onshore terminals. To provide funds for response to and compensation for oil spills when the spiller is unable to do so, the Oil Pollution Act created a $1 billion fund which is funded by a tax on imported and domestic oil.

The Oil Pollution Act requires that all new tank vessels operating in US waters have double hulls, and the phase out, between the years 1995 and 2015, of existing vessels without double hulls. Oil transporters, terminals and other handling facilities are most affected by the expanded technical and operational requirements under OPA 90. Regulations require businesses to provide certificates of financial responsibility and to maintain facility response plans that, among other things, identify and prepare for worst case spill scenarios. Owners and operators of covered facilities and vessels must also conduct emergency response training, consistent with regulations and with area and national contingency plans.

The Prince William Sound port-specific vessel escort plan required by regulations that became effective late in 1994, was updated during 1995, including operational requirements such as enhanced tanker assist capabilities, rudder failure response procedures, and reduced speed in the Valdez Narrows, plus directives on communications and training. The latest Vessel Escort & Response Plan (VERP) was published in December 2001. It reflects significant enhancements made to the escort system such as the requirement to use the most powerful Voith-Schneider tugs in the US and equally powerful tractor tugs.

BP has set performance objectives to enhance emergency preparedness and crisis management at all facilities, and to assure compliance with all related laws such as the Oil Pollution Act. These objectives are designed to be met through appropriate assessment, planning, training and routine exercises, and by the provision or identification of sufficient human and physical resources. BP has established a National Strike Team, the BP Americas Response Team, which consists of approximately 180 trained emergency responders at company locations throughout North America, which is ready to assist in a response to a major incident.

The Resource Conservation and Recovery Act (RCRA) regulates the storage, handling, treatment, transportation and disposal of hazardous and non-hazardous wastes. It also requires the investigation and remediation of certain locations at a facility where such wastes have been handled, released or disposed of. RCRA requirements have become increasingly stringent in recent years, as the EPA expands the definition of hazardous wastes. BP facilities generate and handle a number of wastes regulated by RCRA and have units that have been used for the storage, handling or disposal of RCRA wastes that are subject to investigation and corrective action.

Under the Comprehensive Environmental Response, Compensation, and Liability Act (also known as CERCLA or Superfund), waste generators, site owners, facility operators and certain other parties may be strictly liable for part or all of the cost of addressing sites contaminated by spills or waste disposal regardless of fault or the amount of waste sent to a site.

Additionally, each state has laws similar to CERCLA. A federal tax on oil and certain chemical products was enacted to fund a part of the CERCLA programme but this tax has been suspended for several years while CERCLA reform legislation is debated in the US Congress.

BP has been identified as a Potentially Responsible Party (PRP) under CERCLA and similar state statutes at approximately 800 active sites. A PRP has joint and several liability for site remediation costs and so BP may be required to assume, among other costs, the share attributed to insolvent, unidentified or other parties. BP has the most significant exposure for remediation costs at 63 of these sites. For the remaining sites, the number of PRPs ranges from 20 to 200. BP expects its share of remediation costs at these sites to be small. BP has estimated its potential exposure at all sites where it has been identified as a PRP and has accrued provisions accordingly. BP does not anticipate that its ultimate exposure at these sites individually, or in the aggregate, will be significant except as reported for ARCO in the matters below.

Pursuant to the authority provided under Superfund, the State of Montana has pursued claims against ARCO for compensation alleging damage to natural resources arising out of ARCO's predecessors' mining and mineral processing activities. In addition, a tribe was granted a limited form of intervention in the lawsuit, Montana vs. ARCO. The tribe, as alleged trustees, asserted claims against ARCO for alleged injury to and loss of natural resources located in the Clark Fork River Basin in southwest Montana. The United States Department of Interior also stated an intention to make a claim for natural damages in the Clark River Basin. These matters were settled in part in 1999, however, remaining for disposition are the State's claims for $206 million for restoration damages at several sites.

On June 23, 1989, the EPA filed a CERCLA cost recovery action against Atlantic Richfield Company in the United States District Court for the District of Montana, for the oversight costs at several of the Upper Clark Fork River Basin Superfund sites. Litigation is proceeding on both the EPA's and ARCO's counterclaims against various federal agencies. In the counterclaims, ARCO seeks contributions from the federal agencies for remediation costs and for any natural resource damage liability ARCO might incur in Montana vs. ARCO. The settlements in Montana vs. ARCO, described above, resolved the claims and counterclaims in US vs. ARCO pertaining to one significant site and may provide a framework for possible future settlement of the remaining claims.

The Group is also subject to claims made for natural resource damage (NRD) under several federal and state laws. This is a developing area under US law which could significantly impact the cost of some cleanups. NRD claims have been asserted by government trustees against several refineries and other company operations.

Other significant legislation includes the Toxic Substances Control Act which, among other things, regulates the development, testing, import, export and introduction of new chemical products into commerce; the Occupational Safety and Health Act which, among other things, imposes workplace safety and health, training and process standards to reduce the risks of chemical exposure and injury to employees; and the Emergency Planning and Community Right-to-Know Act which requires emergency planning and spill notification as well as public disclosure of chemical usage and emissions. The Occupational Safety and Health Administration's Process Safety Management rule formalizes the procedures used in identifying and minimizing safety risks at facilities that use certain chemicals in excess of threshold quantities and also in conducting formal documented hazard reviews of covered processes.

In 1993 the South Coast Air Quality Management District (AQMD), which regulates emissions from stationary sources within a four county area of Southern California, including Los Angeles County, adopted a programme requiring phased reductions of oxides of nitrogen and oxides of sulphur for certain facilities, including our Carson Refinery. The aggregate annual emissions of these pollutants will be reduced by 2003 by 80%. AQMD has created a pollution credits programme, in which we participate, that provides flexibility in achieving the requisite levels of emission reductions.

See also Item 8 -- Financial Information -- Legal Proceedings.

United Kingdom and European Union

A European Commission (the Commission) directive for a system of Integrated Pollution Prevention and Control (IPPC) was approved in 1996. This system is based upon ensuring environmental quality standards are not exceeded and the application of Best Available Techniques (BAT) taking into account cost-benefit analysis as a holistic approach. In the event that the use of BAT will fail to meet Environmental Quality Standards (EQS), plant emissions must be reduced further to meet the EQS. This encompasses, among other things, most activities and processes undertaken by the oil industry within the European Union. The European Commission has stated that it hopes that all processes to which it applies will be licensed by July 2005. All plants must be upgraded to BAT standards by November 2007. In the UK, the IPPC directive was implemented through the Pollution Prevention and Control regulations, which replaced UK Integrated Pollution Prevention and Control.

The European Union Large Combustion Plant Directive sets emission limit values for sulphur dioxide, nitrogen oxides and particulates from large combustion plants. It also requires phased reductions in emissions from existing large combustion plants. Implementation by Member States was required by June 1990. In the UK, it has been given effect through the authorization mechanism in Part 1 of the Environmental Protection Act 1990. Large combustion plants required an IPC application to be made by April 30, 1991. Upgrading to the BATNEEC standard is required at the earliest opportunity, at the latest by April 1, 2001. The European Commission has considered proposals to impose emission limit values on small combustion plants. A revised Large Combustion Plant Directive has been agreed and implementation is required by November 27, 2002. Plants will have to comply by 2008.

As part of its overall programme to combat air pollution, the European Union (EU) has set stringent emission limits for new cars and commercial vehicles which are being implemented in stages. Beginning October 1994, the sulphur content of diesel fuel was limited to 0.2% and from October 1996 the limit was further reduced to 0.05%. Heating oils were initially limited to 0.2% with further reductions subject to review. In August, the Federal German Government adopted a regulation to encourage early introduction of low sulphur transport fuels by setting differential excise taxes for gasoline and diesel with maximum 50 parts per million sulphur content from November 2003, and for a maximum of 10 parts per million from January 2001. It also proposed that 10 parts per million sulphur fuels should be adopted at EU level. Implementation of the German regulation depends on tax derogations being agreed by the Commission and the other member states. The Commission made it clear that it will not consider 10 parts per million sulphur fuels within the current Auto/Oil Programme for implementation in 2005.

In 1998, the EU adopted directives to set emission limits for cars and light vehicles to apply from 2000, together with specifications for gasoline and diesel fuel to apply from that date. Some member States indicate that they need energy product taxes to enable them to meet their Kyoto commitments, within the EU burden sharing agreement, and are already implementing national legislation. The Commission is also undertaking a second Auto/Oil Programme to propose changes to other gasoline and diesel fuel specifications from 2005, as well as non-technical measures designed to help meet air quality targets.

In April 1999, the EU adopted a directive to further reduce the sulphur content of liquid fuels, but excluding marine bunker fuel oil, and marine gas oil used by ships crossing a frontier between a third country and an EU Member State. Sulphur in gas oil will be limited to 0.2% from July 2000, and 0.1% from January 2008. From January 2003, sulphur in heavy fuel oil will be limited to 1%, except where use of heavy fuel oil up to 3% sulphur can be used in combustion plants without exceeding specific emission limits, and provided that local air quality standards are met.

As part of its overall approach to improving air quality, in 1997 the Commission proposed its Acidification Strategy, and followed this with its proposal for a strategy to combat tropospheric ozone. The Ozone Strategy was adopted in 1998. Four air quality targets have been adopted as Directives, two more have been proposed by the Commission and a target of 120 micrograms per cubic metre for ozone itself was proposed in 1999, together with a proposal for national emission ceilings for the main polluting emissions. Upon adoption by the Council, these targets and ceilings will be the reference point for further environmental controls of industrial installations at Community and Member State levels.

The carbon monoxide and benzene directive is the second daughter Directive of 96/62/EC on ambient air quality assessment and management and prescribes, among other things, limit values and alert thresholds for carbon monoxide (CO) and benzene. For benzene, a limit value of 0.005 milligrams per cubic metre averaged over a calendar year applies. A margin of tolerance of 100%, to be progressively eliminated from 2003 to 2010, would apply. For carbon monoxide, a limit value of 10 milligrams per cubic metre will apply with a rolling 8-hour averaging period and a 50% margin of tolerance on entry into force, to be reduced to zero from 2003 to 2005.

As part of its ozone strategy, the EU has taken action on volatile organic compounds (VOCs). In late 1994, the European Union adopted the so-called Stage 1 VOC controls which require a 90% cut in emissions over ten years from petroleum transport and storage. In November 1996, the Commission proposed a directive on control of emissions of organic solvents from the solvent-using industry which has the goal of combating low-level ozone by setting emission limits and, as an alternative, targets to be met by national plans. Existing installations would be required to reach compliance by 2007. This proposal was adopted as a Directive during 1998.

EU emission reduction requirements together with reduced sulphur content in fuels may require significant modifications or capital expenditure at facilities and could make the continued operation of particular product lines and facilities uncompetitive.

As part of a package to stabilize carbon dioxide emissions at 1990 levels by the year 2000, the European Commission proposed a combined carbon dioxide energy tax. In March 1997, the Commission proposed instead an energy tax that is intended to be fiscally neutral when applied by Member States. Though formally the proposal replaces the carbon dioxide energy tax proposal that had been blocked in Council, it has as its main objective to provide a harmonized framework by setting minimum levels for national excise taxes on energy products, and to allow Member States greater flexibility to offer tax incentives based on environmental criteria, whilst avoiding barriers to trade within the Single Market. Maximum sulphur levels for gasoline and diesel fuels to apply from 2005 were also agreed as 50 parts per million, which is 0.005% , and 35% maximum aromatic content for gasoline from the same date. In 1999, this was followed by emission limits for heavy commercial vehicles, also based on the Auto/Oil Programme conclusions. The Commission will make further proposals based on the results of its Auto/Oil II Programme and the review of the sulphur content of gasoline and diesel undertaken in parallel.

The European Commission is committed to a harmonized EU approach to liability for environmental damage. This follows a 'green (discussion) paper' in 1992 that focused on a strict liability approach. The Commission issued a proposed directive in January 2002.

PROPERTY, PLANTS AND EQUIPMENT

BP has freehold and leasehold interests in real estate in numerous countries throughout the world, but no one individual property is significant to the Group as a whole. See Exploration and Production under this heading for a description of the Group's significant reserves and sources of crude oil and natural gas. Significant plans to construct, expand or improve specific facilities are described under each of the business headings within this Item.

63

ORGANIZATIONAL STRUCTURE

The significant subsidiary undertakings of the Group at December 31, 2001 and the Group percentage of equity capital (to nearest whole number) are set out below. The principal country of operation is generally indicated by the company's country of incorporation or by its name. Those held directly by the Company are marked with an asterisk (*).

Subsidiary undertakings	%	Country of incorporation	Principal activities
International			
BP Chemicals Investments	100	England	Chemicals
BP Exploration Co.	100	Scotland	Exploration and production
BP International	100	England	Integrated oil operations
BP Oil International	100	England	Integrated oil operations
BP Shipping*	100	England	Shipping
Burmah Castrol	100	England	Lubricants
Europe			
UK			
BP Capital Markets	100	England	Finance
BP Chemicals	100	England	Chemicals

BP Oil UK	100	England	Refining and marketing
Britoil	100	Scotland	Exploration and production
Jupiter Insurance	100	Guernsey	Insurance
France			
BP France	100	France	Refining and marketing and chemicals
Germany			
Deutsche BP	100	Germany	Refining and marketing and chemicals
Netherlands			
BP Capital BV	100	Netherlands	Finance
BP Nederland	100	Netherlands	Refining and marketing
Norway			
BP Amoco Norway	100	Norway	Exploration and production
Spain			
BP Espana	100	Spain	Refining and marketing
Middle East			
BP Egypt Gas	100	USA	Exploration and production
BP Egypt	100	USA	Exploration and production
Africa			
BP Southern Africa	75	South Africa	Refining and marketing
Far East			
Indonesia			
BP Kangean	100	Indonesia	Exploration and production
Singapore			
BP Singapore Pte*	100	Singapore	Refining and marketing
Australasia			
Australia			
BP Australia	100	Australia	Integrated oil operations
BP Developments Australia	100	Australia	Exploration and production
BP Finance Australia	100	Australia	Finance
New Zealand			
BP Oil New Zealand	100	New Zealand	Marketing
Western Hemisphere			
Canada			
BP Canada Energy	100	Canada	Exploration and production
Trinidad			
BP of Trinidad and Tobago	90	USA	Exploration and production
Amoco Trinidad (LNG) B.V.	100	Netherlands	Exploration and production
USA			
Atlantic Richfield Co.	100	USA	(
BP America*	100	USA	(
BP Amoco Chemical Company	100	USA	(Exploration and production,
BP America Production Company	100	USA	(gas and power, refining
BP Company North America	100	USA	(and marketing, pipelines
BP Corporation North America	100	USA	(and chemicals
BP Products North America	100	USA	(
BP West Coast Products	100	USA	(
Standard Oil Co.	100	USA	(

64

ITEM 5 -- OPERATING AND FINANCIAL REVIEW AND PROSPECTS

GROUP OPERATING RESULTS

Years ended December 31,

Highlights		2001	2000	1999
Turnover	($ million)	174,218	148,062	83,566
Total replacement cost operating profit	($ million)	16,135	17,756	8,894
Replacement cost profit before exceptional items	($ million)	9,880	11,214	5,330
Replacement cost profit for the year	($ million)	9,910	11,142	3,280
Historical cost profit for the year	($ million)	8,010	11,870	5,008
Profit per ordinary share (diluted)	(cents)	35.48	54.48	25.68
Dividends per ordinary share	(cents)	22.00	20.50	20.00

On January 1, 2001 the NGL business located in North America was transferred from Refining and Marketing to Gas and Power. Comparative information has been restated. For further information see Item 18 -- Financial Statements -- Note 46.

During 2000 the Company acquired ARCO and Burmah Castrol plc (Burmah Castrol), and also purchased most of ExxonMobil's assets used by the fuels refining and marketing operation in Europe (the 2000 portfolio changes). BP's turnover and results in 2000 reflect the inclusion of ARCO and Burmah Castrol and the full consolidation of the European fuels joint venture from April 14, July 7 and August 1, 2000, respectively.

The 2000 portfolio changes have a significant effect on year on year comparisons: 2001 includes a full year; 2000 includes ARCO, Burmah Castrol and the full consolidation of the European fuels business for varying parts of the year; and 1999 does not include them at all.

The increase in turnover between 2000 and 2001 reflects a full year's contribution from the 2000 portfolio changes and higher natural gas sales volumes partly offset by the effect of lower oil and natural gas prices. The higher turnover in 2000 compared with 1999 reflects a contribution from the 2000 portfolio changes, higher oil and natural gas prices in Exploration and Production and higher natural gas volumes in Gas and Power.

As well as reporting net income (profit after inventory holding gains and losses, calculated on a first-in, first-out basis), and after exceptional items (as defined by UK GAAP: profits and losses on sale of fixed assets and businesses or termination of operations and fundamental restructuring costs), BP also reports results on a replacement cost basis (excluding inventory holding gains and losses) and before exceptional items. In addition the Group discloses the amount and nature of special items which are non-recurring charges and credits that are not classified as exceptional items under UK GAAP. This is done in order to provide a more comparable basis to the results and disclosures of US companies and to indicate underlying trading performance undistorted by significant restructuring, integration and other one-off charges and credits. Special charges have been significant in 2001, 2000 and 1999. The discussion below addresses each of these various measures and disclosures.

Replacement cost profit before exceptional items (which excludes inventory holding gains and losses) was $9,880 million in 2001 compared with $11,214 million in 2000 and $5,330 million in 1999. In addition to exceptional items (as identified under UK GAAP), these results are after special charges of $1,058 million ($821 million after tax) $1,994 million ($1,454 million after tax) and $1,210 million ($876 million after tax), respectively; and depreciation and amortization of $2,477 million, $1,535 million and nil respectively arising from the fixed asset revaluation adjustment and goodwill consequent upon the ARCO and Burmah Castrol acquisitions in 2000. The special items in 2001 primarily comprised Castrol, Erdoelchemie and Solvay integration costs, additional severance costs mainly related to former ARCO employees, and an impairment charge for our partner-operated Venezuelan Lake Maracaibo operations. Also included were costs related to rationalization of the European downstream commercial business and of our Grangemouth site in Scotland. The special items in 2000 primarily comprised ARCO, Vastar and Castrol integration costs, rationalization costs following the BP and Amoco merger, a provision against the Group's chemicals investment in Indonesia, environmental charges and asset write-downs. The major components of the special charges in 1999 were integration costs, costs associated with the restructuring programme, write-downs in respect of asset impairments and project costs in respect of process improvement and outsourcing.

The historical cost profit for 2001 was $8,010 million after inventory holding losses of $1,900 million and including net exceptional gains of $535 million ($30 million after tax). For 2000, the historical cost profit was $11,870 million, including inventory holding gains of $728 million and net exceptional gains of $220 million ($72 million loss after tax). The historical cost profit for 1999 was $5,008 million including inventory holding gains of $1,728 million and after charging net exceptional losses of $2,280 million ($2,050 million after tax).

	Years ended December 31,		
Special items	2001	2000	1999
		($ million)	
Restructuring, integration and rationalization costs			
BP	219	624	903
ARCO (including Vastar)	208	633	--
Castrol	334	151	--
	761	1,408	903
Provision against fixed asset investments	--	181	--
Asset write-downs	175	61	223
Litigation	60	63	60
Environmental charges	--	170	--
	996	1,883	1,186
Interest-- bond redemption charges	62	111	24
Total special items before tax	1,058	1,994	1,210

The trading environment was generally favourable in the first half of 2001. Natural gas and oil prices remained high until clear evidence of the global economic slowdown emerged after the first few months. Business conditions deteriorated in the second half and have been weak since September 11.

Oil prices were 15% down against the levels seen in 2000; refining margins were weak; retailing was fiercely competitive; and in the chemicals sector margins were at levels below those seen at the bottom of the previous business cycle.

We achieved the targets for 2001 we had set in February 2001. Hydrocarbon production grew by 5.5% and underlying performance improvements reached $2.0 billion before tax.

The $5.8 billion targeted reduction in the combined cost structure of the enlarged group (against a 1998 baseline) was achieved in 2001.

The return on average capital employed (ROACE), based on replacement cost profit before exceptional items, was 12% (13% after adjusting for special items) compared with 16% (17% after adjusting for special items) in 2000 and 12% (13% after adjusting for special items) in 1999. Owing to the significant acquisitions that took place in 2000, the annual ROACE for 2000 has been calculated as the average of the four discrete quarterly ROACEs.

Employee numbers increased slightly during 2001, as increases primarily related to the acquisition of Bayer's 50% interest in Erdoelchemie, the Solvay transaction and the Burmah Castrol chemicals businesses previously held for sale, were partly offset by downstream rationalization and a further decrease in former ARCO employees. The acquisitions of ARCO and Burmah Castrol in 2000 increased our employee numbers by approximately 25,000. Following integration and rationalization activities, some 3,000 employees had left by the end of 2000. In 1999, following the merger of BP and Amoco, some 16,000 employees left the Group through severance or outsourcing arrangements; a further 3,000 employees left in 2000. Of these, some 14,000 were based in the USA. The reductions in 1999 and 2000 arose mainly in Houston, Texas; Chicago, Illinois; and Cleveland and Warrensville, Ohio.

In November 2001, BP announced that it will restructure operations at the Grangemouth refining and petrochemical complex in Scotland. The move is part of a series of initiatives and investments to significantly improve the plant's ability to compete in an increasingly difficult international refining and chemicals environment. The reorganization will streamline Grangemouth's three main activities - refining, petrochemicals and the Forties pipeline terminal - into a single organization, designed to simplify site operations while increasing reliability and efficiency. The restructuring is expected to result in the reduction of up to 1,000 jobs at Grangemouth over the next two years.

Owing to the significant acquisitions that took place in 2000, in addition to its reported results, BP is presenting pro forma results adjusted for special items in order to enable shareholders to assess current performance in the context of our past performance and against that of our competitors. The pro forma result, adjusted for special items, has been derived from our UK GAAP accounting information but is not in itself a recognized UK or US GAAP measure.

Reconciliation of reported profit/loss to pro forma result adjusted for special items	Reported	Acquisition amortization (a)	Special items
		($ million)	
Year ended December 31, 2001			
Exploration and Production..........................	12,417	1,759	322
Gas and Power.......................................	521	--	--
Refining and Marketing.............................	3,625	718	487

Chemicals	128	--	114
Other businesses and corporate	(556)	--	73
Replacement cost operating profit	16,135	2,477	996
Interest expense	(1,670)	--	62
Taxation	(4,512)	--	(237)
Minority shareholders' interest	(73)	--	--
Replacement cost profit before exceptional items	9,880	2,477	821
per ordinary share (cents)	44.03		
Year ended December 31, 2000 (c)			
Exploration and Production	14,012	1,174	524
Gas and Power	571	--	--
Refining and Marketing	3,523	440	595
Chemicals	760	--	276
Other businesses and corporate	(1,110)	--	488
Replacement cost operating profit	17,756	1,614	1,883
Interest expense	(1,770)	--	111
Taxation	(4,680)	--	(540)
Minority shareholders' interest	(92)	(79)	--
Replacement cost profit before exceptional items	11,214	1,535	1,454
per ordinary share (cents)	51.82		
Year ended December 31, 1999 (c)			
Exploration and Production	6,983	--	299
Gas and Power	437	--	--
Refining and Marketing	1,614	--	242
Chemicals	686	--	247
Other businesses and corporate	(826)	--	398
Replacement cost operating profit	8,894	--	1,186
Interest expense	(1,316)	--	24
Taxation	(2,110)	--	(334)
Minority shareholders' interest	(138)	--	--
Replacement cost profit before exceptional items	5,330	--	876
per ordinary share (cents)	27.48		

(a) Acquisition amortization refers to depreciation relating to the fixed asset revaluation adjustment and amortization of goodwill consequent upon the ARCO and Burmah Castrol acquisitions in 2000. There was no acquisition amortization in 1999.

(b) The special items refer to non-recurring charges and credits reported in the year.

(c) 1999 and 2000 have been restated to reflect the transfer of the NGL business in North America from Refining and Marketing to Gas and Power.

Return on average capital employed (ROACE)	2001	2000	1999
		($ million)	
Replacement cost basis			
Replacement cost profit before exceptional items	9,880	11,214	5,330
Interest	1,670	1,770	1,316
Minority shareholders' interest	73	92	138
	11,623	13,076	6,784
Average Capital employed (a)	95,801	86,214	58,107
ROACE	12%	16%	12%
Pro forma and special items adjustments			
Acquisition amortization	2,477	1,614	--
Special items (post tax)	775	1,343	876
Average capital employed acquisition adjustment (b)	19,225	20,755	--
ROACE - Pro forma basis adjusted for special items (c)	19%	23%	13%
Historical cost basis			
Historical cost profit after exceptional items	8,010	11,870	5,008
Interest	1,670	1,770	1,316
Minority shareholders' interest	73	92	138
	9,753	13,732	6,462
ROACE	10%	17%	11%

(a) Capital employed is defined as net assets plus total finance debt. As the acquisition of ARCO was completed in April 2000 and Burmah Castrol in July 2000, the average capital employed for 2000 has been calculated as the average of the four discrete quarters.

(b) Acquisition adjustment refers to the fixed asset revaluation adjustment and goodwill consequent upon the ARCO and Burmah Castrol acquisitions.

(c) Based on the pro forma result adjusted for special items and capital employed excluding the fixed asset revaluation adjustment and goodwill resulting from the ARCO and Burmah Castrol acquisitions.

Capital expenditure and acquisitions (a)	2001	2000	1999
		($ million)	
Exploration and Production	8,627	6,383	4,194
Gas and Power	352	336	59
Refining and Marketing	2,386	2,369	1,571
Chemicals	1,446	1,585	1,215

Other businesses and corporate	389	498	204
Capital expenditure	13,200	11,171	7,243
Acquisitions for cash	924	8,936	102
	14,124	20,107	7,345
Disposals	(2,903)	(4,559)(b)	(2,441)
Net Investment	11,221	15,548	4,904

(a) 2000 Excludes $27,506 million for the ARCO acquisition.

(b) Excludes $6,803 million proceeds for the sale of ARCO assets.

Capital expenditure and acquisitions in 2001, 2000 and 1999 amounted to $14,124 million, $47,613 million and $7,345 million, respectively. Acquisitions during 2001 included the purchase of Bayer's 50% interest in Erdoelchemie and a number of minor acquisitions. Expenditure for the year 2000 included the acquisition of ARCO, Burmah Castrol, the ExxonMobil share of the European Joint Venture and the minority interest in Vastar, 2.2% interests in PetroChina and Sinopec, and ExxonMobil's aviation lubricants business. Excluding acquisitions, capital expenditure for 2001 was $13,200 million compared with $11,171 million for 2000, reflecting our growth programme. Capital expenditure excluding acquisitions for 1999 was $7,243 million, reflecting reduced spending following the BP and Amoco merger.

Capital expenditure in 2002 is likely to be around $12-13 billion. This is consistent with historic levels of investment of the enlarged group. By focusing on the better investment opportunities, this level of expenditure should permit investment in Exploration and Production aimed at enabling its targeted production growth of 5.5% in the medium term.

Dividends

The total dividends announced for 2001 were $4,935 million, against $4,625 million in 2000. Dividends per share for 2001 were 22.00 cents, compared with 20.50 cents per share in 2000, an increase of 7%. Following the adoption of FRS 19 in 2002, BP intends to continue to pay dividends in the future of around 60% of its replacement cost profit before exceptional items after adjusting for special items and acquisition amortization, adjusted to mid-cycle operating conditions. Mid-cycle operating conditions reflect adjustments to prices, margins, costs and capacity utilization to levels which we would expect on average over the long term.

The company also intends to continue the operation of the Dividend Reinvestment Plan (DRIP) for shareholders who wish to receive their dividend in the form of shares rather than cash. The BP Direct Access Plan for US and Canadian investors also includes a dividend reinvestment feature.

Consistent with our pledge to return surplus funds to shareholders, a total of 154 million shares were repurchased and cancelled during 2001 at a cost of $1.3 billion. The repurchased shares had a nominal value of $38.5 million and represented 0.7% of ordinary shares in issue at the end of 2000. Since the inception of the share repurchase programme in 2000, 376 million shares have been repurchased and cancelled at a cost of $3.3 billion. No further repurchases were made during the first quarter of 2002. BP will seek approval from shareholders at the April 2002 annual general meeting to continue repurchasing shares. The approval would allow shares to be bought back as and when the Group's funding position permits.

Exceptional Items

For 2001, net exceptional gains, consisting of the profit or loss on sale of fixed assets and businesses or termination of operations, were $535 million before tax. These represented the profits from the sale of the Group's interest in Vysis; the refineries at Mandan, North Dakota, and Salt Lake City, Utah; the Group's interest in the Alliance and certain other pipeline systems in the USA; and BP's interest in the Kashagan discovery in Kazakhstan, were partly offset by losses mainly related to the sale or closure of certain chemicals activities.

Net exceptional gains were $220 million before tax in 2000, and related mainly to disposal profits on the sale of the Group's common interest in Altura Energy, the sale of the Alliance refinery and the divestment of exploration and production interests in Trinidad, the UK and the USA, partly offset by the loss on the sale of certain Venezuelan upstream interests and on the subvention of Singapore Aromatics Company bank loans in connection with the closure of our joint venture.

In 1999 the net exceptional losses of $2,280 million before tax comprised restructuring costs of $1,943 million and a net loss on sales of fixed assets and businesses or termination of operations of $337 million. The restructuring costs arose from restructuring activity across the Group following the merger of BP and Amoco at the end of 1998 and related predominantly to the Group's US operations. The main areas of activity were the elimination of duplication in the former BP and Amoco operations and ongoing restructuring to adapt to the changing business environment, and some further outsourcing. The major elements of the restructuring charges comprised employee severance costs ($1,212 million) and provisions to cover future rental payments on surplus leasehold office accommodation and other property ($297 million). Also included in the restructuring charges were office closure costs, contract termination payments and asset write-offs. The cash outflow for these restructuring charges during 1999 was $976 million and in 2000 was $446 million.

Sales of fixed assets and businesses or termination of operations in 1999 included the sale of distribution terminals and service stations in the USA mandated by the Federal Trade Commission in connection with the BP and Amoco merger. As part of the asset divestment programme, the Group disposed of its Canadian oil properties, its interest in the Pedernales oil field in Venezuela and certain chemicals operations.

Business Operating Results

Total replacement cost operating profit, which is arrived at before inventory holding gains and losses, interest expense, taxation and minority interests, and before exceptional items, was $16,135 million in 2001, $17,756 million in 2000 and $8,894 million in 1999. The business results which follow are presented on this basis.

Exploration and Production

		Years ended D	
		2001	200
Turnover......................................	($ million)	28,229	30,94
Total replacement cost operating profit	($ million)	12,417	14,01
Results included:			
Exploration expense.........................	($ million)	480	59
Key statistics:			
Average BP oil realizations (a)..............	($ per barrel)	22.50	26.6
Average West Texas Intermediate oil price....	($ per barrel)	25.89	30.3
Average Brent oil price......................	($ per barrel)	24.44	28.4
Average BP US natural gas realizations.......	($ per thousand cubic feet)	3.99	3.7
Average Henry Hub gas price (b)..............	($ per thousand cubic feet)	4.26	3.9
Crude oil production (net of royalties) (c)....	(mb/d)	1,931	1,92
Natural gas production (net of royalties) (c)..	(mmcf/d)	8,632	7,60
Total production (net of royalties) (c) (d)....	(mboe/d)	3,419	3,24

(a) Crude oil and natural gas liquids.

(b) Henry Hub First of Month Index.

(c) Includes BP's share of joint ventures and associated undertakings.

(d) Expressed in thousands of barrels of oil equivalent per day (mboe/d). Natural gas is converted to oil equivalent at 5.8 billion cubic feet : 1 million barrels.

Turnover for 2001 was $28,229 million compared with $30,942 million in 2000 and $19,133 million in 1999. The lower turnover in 2001 compared with 2000 reflected the impact of lower oil and natural gas prices, partly offset by higher production, in part through the inclusion of ARCO for a full year. The increase in turnover in 2000 over 1999 resulted from the acquisition of ARCO in 2000 and the effect of significantly higher oil and natural gas prices partly offset by production lost through divestments.

The replacement cost operating profit for 2001 was $12,417 million compared with $14,012 million in 2000 and $6,983 million in 1999. These results are after charging special items of $322 million, $524 million and $299 million respectively; and depreciation and amortization arising from the fixed asset revaluation adjustment and goodwill consequent upon the ARCO acquisition of $1,759 million, $1,174 million and nil respectively. Special items for 2001 included a $175 million impairment of our partner operated Venezuelan Lake Maracaibo operations, following a technical reassessment, $77 million additional severance costs, $60 million litigation and $10 million restructuring costs related to the Grangemouth operating site in Scotland. The special charges in 2000 comprise mainly ARCO and Vastar integration costs. In 1999 special charges were asset write-downs and integration and rationalization costs following the BP and Amoco merger at the end of 1998.

Compared with a year ago, 2001 profit reflects the oil price decrease of over $4 per barrel, partly offset by operational improvements and the inclusion of ARCO for the whole year, compared to only around nine months (from April 14) in 2000 and other portfolio changes.

The increased profit for 2000 compared with 1999 reflected significantly higher oil and natural gas prices, the ARCO acquisition and operational improvements. Average realized oil prices were $9.89 a barrel higher than the prior year and North American natural gas prices (i.e. our principal gas market) were 76% above their 1999 level.

Total hydrocarbon production for 2001 increased 5.5%, in line with our growth target. The reserve replacement ratio was 191% with 2.2 billion barrels of oil equivalent booked through extensions, discoveries, revisions and improved recovery. Replacement exceeded production for the eighth consecutive year.

Hydrocarbon production in 2000 was up 4% on 1999. Higher underlying (excluding the net impact of acquisitions and divestments) natural gas production and the ARCO acquisition more than offset lower oil production caused by the disposal of our common interest in Altura Energy and other non-core properties and the effect of a reduced capital spending programme in 1999.

In 2001, finding and development costs averaged $3.68 per barrel of oil equivalent, compared with $3.29 in 2000 and $3.21 in 1999. Unit lifting costs were $2.70 per barrel of oil equivalent compared with $2.60 in 2000 and $2.70 in 1999.

In support of continued growth, 2001 capital expenditure, at $8.9 billion (including $0.3 billion of acquisitions), was nearly $2.5 billion higher than last year. During 2001, the Mad Dog development (BP 60.5% and operator), in the US Gulf of Mexico, was approved. Also, BP announced that the assets of Chernogorneft have been returned to Sidanco (BP 11.2%). This completes the restructuring of Sidanco with its debt substantially repaid and non-core assets disposed of. Sidanco is now positioned as a low-cost Russian producer.

Our increased capital investment programme is beginning to bear fruit. During 2001 oil began to flow from the Northstar field offshore Alaska, 250 miles north of the Arctic Circle. Other significant projects went into production during the year, including the Crosby and Mica fields, both in 4,400 feet of water in the Gulf of Mexico, USA and the Girassol field, in 4,200 feet of water offshore Angola. To continue the development of our natural gas reserves in Trinidad, a new liquefied natural gas (LNG) processing plant is planned to start up in 2002, and the engineering and design work on an additional, larger plant has begun. The Horn Mountain, King's Peak and King fields in the Gulf of Mexico are also scheduled for start-up in 2002.

We focused too on appraising and progressing our previous discoveries. In 2001, we sanctioned the Thunder Horse (previously known as Crazy Horse) and Holstein fields and the Mardi Gras pipeline in the Gulf of Mexico, as well as developments in Angola, Egypt, Alaska, Norway, Azerbaijan, Trinidad, Argentina and West of Shetland, UK. Exploration successes during the year included discoveries in Trinidad, Egypt and offshore Angola.

We entered the detailed engineering phase of the Baku-Tbilisi-Ceyhan oil pipeline, scheduled to come on stream by 2005. This will link our growing oil reserves in the Caspian to markets all over the world.

The effective application of the very best technology leads to higher productivity and improved performance. Once new technologies have been proved operationally, we apply them quickly and systematically across the Group to take advantage of our global scale. For example, in 2001 we used time-lapse 3-D seismic imaging in 19 North Sea fields to add new production and reserves, and successfully tested a lightweight mooring buoy system that should reduce drilling costs in deep water locations. We have also developed technologies to reduce the cost of producing and transporting LNG.

Gas and Power

		Years ended December 31,		
		2001	2000	1999
Turnover	($ million)	39,208	21,013	8,073
Total replacement cost operating profit	($ million)	521	571	437
Total natural gas sales volumes (a)	(mmcf/d)	18,794	14,471	8,930
Total NGL sales volumes	(mb/d)	410	349	307

(a) Includes marketing, trading and supply sales.

The Gas and Power business is responsible for BP's world-wide natural gas marketing activities (although some long term natural gas sales contracts are also included within Exploration and Production) and all business development opportunities in natural gas, including gas-fired power generation.

On January 1, 2001, the NGL business located in North America was transferred to Gas and Power from Refining and Marketing. Comparative information has been restated.

Turnover has increased from $8,073 million in 1999 to $21,013 million in 2000 and to $39,208 million in 2001. The increase across the three years is mainly attributable to higher sales volumes in the natural gas marketing and trading business.

Replacement cost operating profit for 2001 was $521 million compared with $571 million in 2000 and $437 million in 1999. The 2001 result is down on 2000 due to a lower contribution from NGLs, partly offset by better results from marketing and trading and Ruhrgas. In 2000 the NGL business benefited from exceptionally strong margins which have returned to more normal levels in 2001.

The higher profit in 2000 compared with 1999 reflected higher NGL margins and higher natural gas sales volumes.

Gas sales increased from 8.9 billion cubic feet per day in 1999 to 14.5 billion cubic feet per day in 2000, and increased further to 18.8 billion cubic feet per day in 2001.

Gas sales volumes were well ahead of our 2001 target, especially in North America where we are one of the largest natural gas marketers. In Spain, as part of our expansion into European natural gas, we consolidated our position as the leading new entrant to the deregulated natural gas market.

In December 2001, Pertamina, our partner in the Tangguh, Indonesia natural gas project, signed a Letter of Intent with the project's first potential customer in the Philippines.

Capital expenditure and acquisitions for 2001 was $359 million compared with $336 million in 2000 and included an additional investment in Green Mountain Energy Company. Expenditure for 2000 included $125 million for the first two instalments on two LNG ships and our initial investment in Green Mountain Energy Company.

Refining and Marketing

		Years ended December 31,		
		2001	2000 (a)	1999(a)
Turnover.................................	($ million)	120,233	107,883	60,143
Total replacement cost operating profit...	($ million)	3,625	3,523	1,614
Global Indicator Refining Margin (b)......	($/bbl)	4.06	4.22	1.24
Refinery throughputs......................	(mb/d)	2,929	2,916	2,522
Total marketing sales	(mb/d)	3,797	3,420	2,879

(a) Includes BP's share of the BP/Mobil European joint venture until August 1, 2000.

(b) The Global Indicator Refining Margin (GIM) is the average of seven regional indicator margins weighted for BP's crude refining capacity in each region. Each regional indicator margin is based on a single representative crude with product yields characteristic of the typical level of upgrading capacity.

On January 1, 2001, NGL business located in North America was transferred to Gas and Power from Refining and Marketing. Comparative information has been restated.

The increases in turnover between 1999 and 2000, and 2000 and 2001 principally reflected the acquisitions of ARCO and Burmah Castrol and the consolidation of the European fuels business during 2000. Turnover for 2000 included ARCO from April 14, Burmah Castrol from July 7 and the European fuels business from August 1. Turnover for 2001 includes these businesses for the full year.

The replacement cost operating profit for 2001 was $3,625 million compared with $3,523 million in 2000 and $1,614 million in 1999. These results are after special charges of $487 million, $595 million and $242 million respectively; and depreciation and amortization arising from the fixed asset revaluation adjustment and goodwill consequent upon the ARCO and Burmah Castrol acquisitions of $718 million, $440 million and nil, respectively. Special charges in 2001 comprised Castrol integration costs, rationalization costs in the downstream European commercial business, Grangemouth restructuring and additional severance charges mainly related to former ARCO employees. The special charges in 2000 mainly comprised ARCO and Burmah Castrol integration costs, rationalization costs following the BP and Amoco merger, environmental charges and litigation costs. For 1999 special charges related principally to integration and rationalization costs following the BP and Amoco merger and asset write-downs.

The 2001 result reflects the benefit of the 2000 portfolio changes and improved marketing volumes, offset by the effects of a larger refinery maintenance programme. We delivered another strong performance, led in particular by US refining in the first half of the year, where margins were very good. In both the USA and Europe, refining margins declined in the latter part of 2001. In September, in line with our strategy, we completed the sale of refineries at Mandan, North Dakota and Salt Lake City, Utah in the USA.

Marketing experienced significant competitive pressures throughout 2001. We delivered growth of 23% (7% excluding portfolio changes) in convenience store sales and 8% in retail fuel volumes, reflecting the full-year benefit of the 2000 portfolio changes and the rollout of the new BP Connect convenience sites. We also achieved a unit cash cost reduction of 6% during the year, compared to our target of 2.5%.

Compared with 1999, the 2000 result benefited from the 2000 portfolio changes, cost reductions and a strong oil trading performance. In 2000, refining margins were stronger in all regions than in 1999. Marketing margins came under pressure due to the inability to pass through high product prices in competitive markets.

The introduction of the BP Connect retail convenience store brand continued throughout 2001, bringing the total number of new-format sites to 339, located in the USA, Europe, Australia and New Zealand. Good progress was also made on the rebranding and reimaging of former BP and Amoco retail sites with the new colours and logo, with more than 4,600 sites being completed. We also grew our market share in the Castrol lubricants business despite the difficult trading conditions.

We took a very important step in Europe with the acquisition of 51% of Veba Oil from the German utility E.ON. The deal was completed early in 2002, finalizing one part of the arrangements originally announced in mid-2001. It adds about 1.5 million new customers a day, making us the largest fuels retailer in Germany and enhancing our capacity to supply clean fuels in central Europe.

Capital expenditure and acquisitions in 2001 was $2,415 million compared with $8,693 million in 2000 and $1,571 million in 1999. Excluding acquisitions, capital expenditure was $2,386 million compared with $2,369 million for the previous year.

Chemicals

		Years ended December 31,		
		2001	2000	1999
Turnover	($ million)	11,515	11,247	9,392
Total replacement cost operating profit	($ million)	128	760	686
Chemicals Indicator Margin (a)	($/te)	108 (b)	126 (c)	114
Production volumes (d)	(kte)	22,716	22,065	21,853

(a) The Chemicals Indicator Margin (CIM) is a weighted average of externally-based product margins. It is based on market data collected by Chem Systems in their quarterly market analyses, then weighted based on

BP's product portfolio. While it does not cover our entire portfolio, it includes a broad range of products. Amongst the products and businesses covered in the CIM are the olefins and derivatives, the aromatics and derivatives, linear alpha olefins, acetic acid, vinyl acetate monomer and nitriles. Not included are fabrics and fibres, plastic fabrications, poly alpha olefins, anhydrides, engineering polymers and carbon fibres, speciality intermediates, and the remaining parts of the solvents and acetyls businesses.

(b) Provisional. The data for the current year is based on eleven months of actual data and one month of provisional data.

(c) Restated following review of product margins with Chem Systems.

(d) Includes BP share of joint ventures, associated undertakings and other interests in production.

73

Turnover has increased from $9,392 million in 1999 to $11,247 million in 2000 and to $11,515 million in 2001. The higher turnover in 2001 compared with 2000 reflects the consolidation of Erdoelchemie from May 2, 2001 partly offset by the effect of lower prices. The increase in turnover from 1999 to 2000 reflected higher prices and higher production.

Replacement cost operating profit for 2001 was $128 million compared with $760 million in 2000, special charges of $114 million, $276 million and $247 million respectively. Special charges for 2001 include Grangemouth restructuring and costs related to Erdoelchemie and Solvay integration. In 2000 special charges comprised provision against a chemicals investment in Indonesia, asset write-downs and rationalization costs following the BP and Amoco merger. Special charges in 1999 related mainly to integration and rationalization costs following the BP and Amoco merger, asset write-downs and litigation costs.

The business environment for chemicals was very difficult throughout 2001 with margins at levels below those seen at the bottom of the previous business cycle. After early plant operating problems, we recorded lower unit costs through restructuring and improved plant performance in the second half of 2001.

Production for the year was 22.7 million tonnes, up 3% on 2000 due to new production and acquired assets.

Major restructuring continued throughout 2001, aimed at repositioning the portfolio and lowering the cost base. In addition to the special charges above, the 2001 results include further rationalization costs of $102 million.

Chemicals' demand was firm in the first half of 2000, but then weakened in the final two quarters as the global economy slowed. Annual production rose 1% to 22.1 million tonnes, despite operational difficulties at Grangemouth, Scotland. Several initiatives to promote cost and capital efficiency helped offset pressure on margins that were close to cyclical lows, as high oil and natural gas prices boosted feedstock costs. The weakness of the euro added pressure on margins in our European operations. Overall, productivity improvements in 2000 more than offset the effects of the weaker environment.

In 2001, the strengthening of our chemicals business focused on building a limited set of leading global positions. We took full ownership of Erdoelchemie through acquisition of Bayer's 50% stake. A deal was completed with Solvay to combine both companies' high-density polyethylene businesses. In addition, Solvay's polypropylene business was transferred to BP and our non-core engineering polymers business was transferred to Solvay. We also announced the closure of a number of disadvantaged or non-core plants in the UK and USA.

Capital expenditure and acquisitions in 2001 was $1,926 million compared with $1,585 million in 2000 and $1,215 million in 1999. Excluding acquisitions, capital expenditure was $1,446 million, $1,585 million and $1,215 million respectively.

Other Businesses and Corporate

		Years ended December 31,		
		2001	2000	1999
Turnover..............................	($ million)	783	249	198
Replacement cost operating loss........	($ million)	(556)	(1,110)	(826)

Other Businesses and Corporate comprises Finance, BP Solar, our coal and aluminium assets, our investments in PetroChina and Sinopec, interest income and costs relating to corporate activities worldwide.

The net cost of Other Businesses and Corporate amounted to $556 million in 2001, $1,110 million in 2000 and $826 million in 1999. These net costs include special charges of $73 million, $488 million and $398 million respectively. Special charges in 2001 comprise additional severance charges mainly related to former ARCO employees. For 2000 special charges were ARCO integration costs, rationalization costs following the BP and Amoco merger and environmental charges. Special charges in 1999 were principally integration and rationalization costs following the BP and Amoco merger at the end of 1998.

BP Solar production and shipments for 2001 were 30% higher than in 2000, which in turn were 31% higher than in 1999. A total of 55 megawatts (MW) of solar panel generating capacity was sold in 2001 (2000, 42 MW and 1999, 32 MW).

During 2000, we purchased a 2.2% interest in PetroChina for $578 million and a 2.2% interest in Sinopec for $416 million -- two of Asia's largest oil and natural gas companies.

74

Interest Expense

Interest expense in 2001 was $1,670 million compared with $1,770 million in 2000 and $1,316 million in 1999. These amounts included special charges of $62 million, $111 million and $24 million respectively, arising from the early redemption of bonds. After adjusting for these special charges, the decrease in Group interest expense in 2001 compared with 2000 mainly reflects lower interest rates, partly offset by the impact of revaluing environmental and other provisions at a lower interest rate. After adjusting for special charges the increase in interest expense between 1999 and 2000 reflects higher debt and interest rates.

Taxation

The charge for corporate taxes in 2001 was $5,017 million, compared with $4,972 million in 2000 and $1,880 million in 1999. The effective rate on historical cost profit was 38% in 2001, 29% in 2000 and 27% in 1999. The higher rate in 2001 compared to 2000 reflects the full year effect of the ARCO and Burmah Castrol acquisition amortization charge (which is non-deductible for tax purposes), together with non-deductible inventory holding losses (versus inventory gains in 2000). The slightly higher rate in 2000 compared with 1999 reflects the non-deductible acquisition amortization charge in 2000 (but not in 1999), and reduced inventory holding gains, partly offset by low tax relief on net exceptional items in 1999.

The effective rate on replacement cost profit before exceptional items was 31% compared with 29% in 2000 and 28% in 1999. The higher rate in 2001 was due to the full-year effect of the ARCO and Burmah Castrol acquisition amortization charge (which is non-deductible for tax purposes). The increase in the rate in 2000 over 1999 was caused by the acquisition amortization charge in 2000 but not in 1999, offset by lower timing benefits in 1999.

Outlook

The outlook for oil and gas prices is weaker than last year because of the state of the global economy, a mild US winter and reduced jet fuel demand following the events of September 11. The crude oil market looks broadly balanced for the first half of 2002, if OPEC's latest round of quota reductions offsets current demand weakness. Additional OPEC oil may be required in the second half of the year to balance the market if demand improves in line with an economic recovery. In the US natural gas market, a combination of recovery and lower natural gas prices may boost demand during 2002, while lower drilling activity could curtail growth in domestic production. Refining margins have been poor so far in 2002 and may remain under pressure in the near term because of weak oil product demand growth and relatively high inventories, especially in the key US market. Retail margins are currently weaker owing to intense competitive pressure. In chemicals, the near-term pattern of demand is likely to be unchanged.

Environmental Expenditure

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Operating expenditure	575	653	414
Capital expenditure	423	298	246
Clean-ups	67	81	92
New provisions for environmental remediation	180	228	145
New provisions for decommissioning	156	139	80

Operating and capital expenditure on the prevention, control, abatement or elimination of air, water and solid waste pollution is often not incurred as a discrete identifiable transaction. Instead, it forms part of a larger transaction which includes, for example, normal maintenance expenditure. The figures for environmental operating and capital expenditure in the table are therefore estimates, based on the definitions and guidelines of the American Petroleum Institute.

Environmental expenditure decreased in 2001 compared with 2000, reflecting benefits realized from environmental programmes in prior years and the impact of refinery disposals. Capital expenditure increased in 2001 compared with 2000 as a result of projects to reduce refinery emissions associated with our agreement with the Environmental Protection Agency and upgrades required to meet new US emission requirements for gasoline and highway diesel. Further increases in capital expenditure are expected in the near term. In addition to operating and capital expenditures, we also create provisions for future environmental remediation. Expenditure against such provisions is normally incurred in subsequent periods and is not included in environmental operating expenditure reported for such periods.

Provisions for environmental remediation are made when a clean-up is probable and the amount reasonably determinable. Generally, their timing coincides with commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The extent and cost of future remediation programmes are inherently difficult to estimate. They depend on the scale of any possible contamination, the timing and extent of corrective actions, and also the Group's share of the liability. Although the cost of any future remediation could be significant, and may be material to the result of operations in the period in which it is recognized, we do not expect that such costs will have a material effect on the Group's financial position or liquidity. We believe our provisions are sufficient for known requirements; and we do not believe that our costs will differ significantly from those of other companies (with similar assets) engaged in similar industries or that our competitive position will be adversely affected as a result.

In addition, we make provisions to meet the cost of eventual decommissioning of our oil- and gas-producing assets and related pipelines. Provisions for environmental remediation and decommissioning are usually set up on a discounted basis, as required by Financial Reporting Standard No. 12, 'Provisions, Contingent Liabilities and Contingent Assets'. Further details of decommissioning and environmental provisions appear in Item 18 -- Financial Statements -- Note 27. See also Item 4 -- Information on the Company -- Environmental Protection.

Insurance

The Group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. This is because external insurance is not considered an economic means of financing losses for the Group. Losses will therefore be borne as they arise rather than being spread over time through insurance premia with attendant transaction costs. The position is reviewed periodically.

The Euro

As a result of the Treaty establishing the European Community, as amended by the Treaty on European Union (the Treaty), European economic and monetary union (EMU) has occurred for eleven out of the fifteen member countries of the European Union (participating countries). The final stage of the Treaty began on January 1, 1999.

For the participating countries, the fixed conversion rates between their sovereign currencies (legacy currencies) prior to January 1, 1999 and the euro have been established. The euro has been adopted as their common legal currency. The legacy currencies remained legal tender as denominations of the euro between January 1, 1999 and January 1, 2002 (the transition period).

The United Kingdom has not participated initially in EMU, but may do so at a later time. The current policy of the UK government is that any decision to join EMU will only be taken after a national referendum of the people.

By the end of 2001 all BP's business activities in the countries of the euro zone were ready for full operation in euros following the official launch of the notes and coins on January 1, 2002. The Company's commercial and financial processes had been successfully adapted with effect from January 1, 1999 to allow its European operations to undertake transactions in the euro and capture competitive advantage offered by the new currency. In common with experience generally across Europe, the actual level of transactions in euro which had previously been low rose significantly in the second half of 2001. The costs associated with the euro programme are estimated at $100 million, of which more than $90 million had been incurred by the end of the year. Of this amount, $30 million has been capitalized.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flow

	Years ended December 31, 2001	2000	1999
	($ million)		
Net cash inflow from operating activities..................	22,409	20,416	10,290
Net cash inflow (outflow)	1,002	3,743	(82)

Net cash inflow for 2001 was $1,002 million, compared with an inflow of $3,743 million in 2000. This is primarily driven by higher capital expenditure and significantly lower divestment proceeds (2000 included proceeds from the sale of the ARCO Alaska assets). The improvement in cash flow between 1999 and 2000 results from an almost doubling of operating cash flow partially offset by higher tax payments and net cash outflows from capital expenditure, acquisitions and disposals.

Net cash inflow from operating activities increased to $22,409 million in 2001 from $20,416 million in 2000 and $10,290 million in 1999. Lower income in 2001 compared with 2000 was more than compensated for by lower working capital requirements and higher depreciation. Net cash inflow from operating activities increased to $20,416 million in 2000 from $10,290 million in 1999. The main factor in this improvement was the increased operating earnings.

Dividends from joint ventures and associated undertakings have decreased from $1,168 million in 1999 to $1,039 million in 2000 and to $632 million in 2001. The principal factor underlying this decrease was the dissolution in August, 2000 of the BP/Mobil European joint venture although in 2000 the decline was partially offset by an increase in dividends from associated undertakings.

The net cash outflow from servicing of finance and returns from investments was $948 million in 2001, $892 million in 2000 and $1,003 million in 1999. The higher cash outflow in 2001 compared with 2000 arises because the decrease in interest payments was more than offset by the decrease in interest receipts. The net cash outflow from servicing of finance and returns from investments decreased to $892 million from $1,003 million in 1999, principally because of the lower payment of dividends to minority shareholders. The increase in interest payments was largely offset by the increase in interest receipts.

Tax payments decreased to $4,660 million in 2001 from $6,198 million in 2000 reflecting lower profit in 2001 and additional taxes in 2000 related to the FTC mandated disposal of ARCO's Alaskan operations. The increase in tax payments from $1,260 million in 1999 to $6,189 million are attributable to higher profits and the FTC mandated disposal in 2000.

Payments for capital expenditures on fixed assets net of proceeds from sales of fixed assets, amounted to $9,849 million in 2001 compared with $7,072 million in 2000 and $5,385 million in 1999. The increase in 2001 over 2000 was due to higher capital expenditure and lower disposal proceeds. Higher capital expenditure in 2000 compared with 1999 was partly offset by higher disposal proceeds. We are targeting annual investment in the $12-13 billion range over the period 2001 to 2003 which is consistent with historic levels of investment for the enlarged Group.

Acquisitions and disposals of businesses produced a net cash outflow of $1,755 million compared with an inflow of $865 million in 2000 reflecting decreased acquisition activity and lower disposal proceeds. 2000 included disposal proceeds of $6,803 million, for the FTC mandated sales, which were largely offset by the Burmah Castrol acquisition. Acquisitions and disposals of businesses produced a net cash inflow of $243 million in 1999. The increase in disposal proceeds of $7,041 million between 1999 and 2000 was largely offset by increased spend on acquisitions and investments in associated undertakings.

Overall net cash outflow for capital expenditure and acquisitions, net of disposals, was $11,604 million (2000 $6,207 million and 1999 $5,142 million).

Dividend payments have increased to $4,827 million from $4,415 million in 2000 and $4,135 million in 1999. The increase in 2001 compared with 2000 reflects the impact of the higher dividend partly offset by share repurchases during 2001. Higher dividend payments in 2000 compared with 1999 reflect the increase in shares in issue as a result of the ARCO acquisition and the dividend increase in the third quarter of 2000, partially offset by share repurchases during 2000.

Financing the Group's Activities

The Group's principal commodity, oil, is priced internationally in US dollars. Group policy has been to minimize economic exposure to currency movements by financing operations with US dollar debt wherever possible, otherwise by using currency swaps when funds have been raised in currencies other than dollars.

The Group's finance debt is almost entirely in US dollars and at December 31, 2001 amounted to $21,417 million (2000 $21,190 million) of which $9,090 million (2000 $6,418 million) was short term.

Net debt, that is debt less cash and liquid resources, was $19,609 million at the end of 2001, an increase of $250 million over the year. The ratio of net debt to net debt plus equity was 21% at the end of both 2001 and 2000. After adjusting for the fixed asset revaluation adjustment and goodwill consequent upon the ARCO and Burmah Castrol acquisitions, the ratio of net debt to net debt plus equity was 26%. Our target range for this ratio for periods to December 31, 2001 was 20-30%.

The maturity profile and fixed/floating rate characteristics of the Group's debt are described in Item 18 -- Financial Statements -- Note 25.

In addition to reported debt, BP uses conventional off balance sheet arrangements such as operating leases and borrowings in joint ventures and associated undertakings. At December 31, 2001 the Group's share of third party borrowings of joint ventures and associated undertakings was $460 million and $1,136 million respectively. These amounts are not reflected in the Group's debt on the balance sheet.

The Company has issued guarantees under which amounts outstanding at December 31, 2001 were $19,900 million (2000 $14,133 million), including $19,843 million (2000 $14,076 million) in respect of borrowings by its subsidiary undertakings.

At December 31, 2001 contracts had been placed for authorized future capital expenditure estimated at $4,712 million, mainly in respect of exploration and production activities. Such expenditure is expected to be financed largely by cash flow from operating activities. The Group also has access to significant sources of liquidity in the form of committed facilities and other funding through the capital markets. At December 31, 2001, the Group had available undrawn committed borrowing facilities of $3,400 million ($3,450 million at December 31, 2000).

The following table summarizes the principal financial obligations which are described in Item 18 -- Financial Statements -- Notes 25 and 32.

	Payments due by period					
	Total	Within 1 year	1-2 years	2-3 years	3-4 years	4-5 years
	($ million)					
Long-term borrowings	12,751	1,993	1,460	641	1,566	651
Finance lease obligations	3,648	97	159	165	173	177
Operating leases	5,866	958	729	573	515	465

We have in place a European Debt Issuance Programme (DIP) and a US Shelf Registration under each of which the Group may raise an aggregate of $6 billion of debt for maturities of one month or longer. At March 26, 2002, the amount drawn down against the DIP was $564 million, and $1,500 million under the US Shelf Registration.

Commercial paper markets in the US and Europe are a primary source of liquidity for the Group. At December 31, 2001 the outstanding commercial paper amounted to $4,634 million (2000 $2,943 million).

BP believes that, taking into account the substantial amounts of undrawn borrowing facilities available, the Group has sufficient working capital for foreseeable requirements.

Liquidity Risk

Liquidity risk is the risk that suitable sources of funding for the Group's business activities may not be available. The Group has long-term debt ratings of Aa1 and AA+ assigned respectively by Moody's and Standard and Poor's. The Group has access to a wide range of funding at competitive rates through the capital markets and banks. It co-ordinates relationships with banks, borrowing requirements, foreign exchange requirements and cash management centrally. The Group believes it has access to sufficient funding and has also undrawn committed borrowing facilities to meet currently foreseeable borrowing requirements. At December 31, 2001, the Group had available undrawn committed facilities of $3,400 million. These committed facilities, which are mainly with a number of international banks, expire in 2002. The Group expects to renew the facilities on an annual basis.

Credit Risk

Credit risk is the potential exposure of the Group to loss in the event of non-performance by a counterparty. The credit risk arising from the Group's normal commercial operations is controlled by individual operating units within guidelines. In addition, as a result of its use of financial and commodity instruments, including derivatives, to manage market risk, the Group has credit exposures through its dealings in the financial and specialized oil and natural gas markets. The Group controls the related credit risk by entering into contracts only with highly credit-rated counterparties and through credit approvals, limits and monitoring procedures, and does not usually require collateral or other security. Counterparty credit validation, independent of the dealers, is undertaken before contractual commitment. The Group has not experienced material non-performance by any counterparty.

CRITICAL ACCOUNTING POLICIES AND NEW ACCOUNTING STANDARDS

UK GAAP Accounting Policies

The preparation of financial statements in conformity with UK generally accepted accounting practices (UK GAAP) requires the Group to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the accounts and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from the estimates and assumptions used.

The Company believes that the critical accounting policies and areas that require the most significant judgments and estimates to be used in the preparation of consolidated financial statements are in relation to oil and natural gas reserves, depreciation and amounts provided, impairment, provisions for deferred taxation, decommissioning, and environmental liabilities, and pension and other postretirement benefits.

Oil and Gas Reserves

BP's oil and natural gas reserves are estimated by the Group's petroleum engineers in accordance with industry standards and SEC regulations. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Accordingly, these estimates do not include probable or possible reserves. Estimated oil and gas reserves are based on available reservoir data and prices and costs as of the date the estimate is made and are subject to future revision.

Depreciation and Amounts Provided

The Group follows the successful efforts method of accounting for its oil and gas activities. This accounting principle, among other things, requires that the capitalized costs for proved oil and gas properties (which include the costs of drilling successful wells) be amortized on the basis of oil-equivalent barrels that are produced in a period as a percentage of the total estimated proved reserves. The impact of changes in estimated proved reserves are dealt with prospectively by amortizing the remaining book value of the asset over the expected future production. If proved reserve estimates are revised downward, earnings could be affected by higher depreciation expense or an immediate write-down of the property's book value (see impairment discussion below).

Other tangible and intangible assets are depreciated on the straight- line method over their estimated useful lives. The average estimated useful lives of refineries are 20 years, chemicals manufacturing plants 20 years and service stations 15 years. Other intangibles are amortized over a maximum period of 20 years, with most goodwill amortized over 10 years.

Impairment of Assets

Fixed assets and goodwill are assessed for impairment if there are events or changes in circumstances which indicate that carrying values may not be recoverable. This entails comparing the carrying value of the income-generating unit and associated goodwill with the recoverable amount of the asset, that is, the higher of net realizable value and value in use. Value in use is usually determined on the basis of discounted estimated future net cash flows.

For oil and natural gas properties, the expected future cash flows are estimated based on the Group's plans to continue to produce and develop proved and associated risk-adjusted probable and possible reserves. Expected future cash flows from the sale or production of reserves are calculated based on the Group's best estimate of future oil and gas prices. The estimated future level of production is based on assumptions about future commodity prices, lifting and development costs, field decline rates, market demand and supply, economic regulatory climates and other factors.

Relatively modest amounts of impairment are routinely recognized in the Group's results as a result of adverse changes in the recoverable reserves from oil and natural gas fields, low plant utilization or reduced profitability. However, if there are low oil prices or natural gas prices or refining margins or chemicals margins over an extended period, the Group may need to recognize significant impairment charges.

Deferred Taxation

For accounting periods up to and including 2001, the Group provided deferred taxation on a partial provision basis (see below for a discussion of the new accounting standard, FRS 19, that has been adopted in 2002). This requires estimates to be made of the extent to which timing differences are expected to reverse in the foreseeable future.

Decommissioning and Environmental Costs

The Group holds provisions for the future decommissioning of oil and natural gas production facilities and pipelines at the end of their economic lives. The largest asset removal obligations facing BP relate to the removal and disposal of oil and natural gas platforms and pipelines around the world. The estimated discounted costs of dismantling and removing these facilities are accrued at the commencement of production. Most of these removal obligations are many years in the future and the precise requirements that will have to be met when the removal event actually occurs are uncertain. Asset removal technologies and costs are constantly changing, as well as political, environmental, safety and public expectations.

BP also makes judgments and estimates in recording costs and establishing provisions for environmental clean-up and remediation costs which are based on current information on costs and expected plans for remediation. For environmental provisions, actual costs can differ from estimates because of changes in laws and regulations, public expectations, discovery and analysis of site conditions and changes in clean-up technology.

Pensions and Other Postretirement Benefits

Accounting for pensions and other postretirement benefits involves judgment about uncertain events, including estimated retirement dates, salary levels at retirement, mortality rates, rates of return on plan assets, determination of discount rates for measuring plan obligations, health care cost-trend rates and rates of utilization of health care services by retirees. These assumptions are based on the environment in each country. Determination of the projected benefit obligations for the company's defined benefit pension and postretirement plans are important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. The assumptions used may vary from year-to-year, which will affect future results of operations. Any differences between these assumptions and the actual outcome will also impact future results of operations.

Impact of New UK Accounting Standards

The Group has adopted Financial Reporting Standard No. 19 'Deferred Tax' with effect from January 1, 2002. If this new standard had been applied to the reported results for 2001, the tax charge for the year would have increased by $1,358 million to $6,375 million. In addition, at December 31, 2001 there would have been a reduction of $9,050 million in shareholders' interest.

In December 2000, the UK Accounting Standards Board issued Financial Reporting Standard No. 17 'Retirement Benefits' ('FRS17'). This standard is fully effective for accounting periods ending on or after June 22, 2003. Certain of the disclosure requirements are effective for periods prior to 2003. FRS 17 requires that financial statements reflect at fair value the assets and liabilities arising from an employer's retirement benefit obligations and any related funding. The operating costs of providing retirement benefits are recognized in the period in which they are earned together with any related finance costs and changes in the value of related assets and liabilities. The Company has not yet completed its evaluation of the impact of adopting FRS17 on the Group's results of operations. It is believed that at December 31, 2001 the impact on shareholders' interest would not be significant.

US GAAP

The consolidated financial statements of BP are prepared in accordance with UK GAAP, which differs in certain respects from US generally accepted accounting principles (US GAAP). The principal differences between US GAAP and UK GAAP for BP Group reporting are discussed in Note 43 of Notes to Financial Statements.

New US GAAP Accounting Standards adopted in 2001

On January 1, 2001 the Group adopted Statement of Financial Accounting Standards No. 133 'Accounting for Derivative Instruments and Hedging Activities' (SFAS 133) as amended by Statement Nos. 137 and 138, for US GAAP reporting.

SFAS 133, as amended, requires that all derivative instruments be recorded on the balance sheet at their fair value. Changes in the fair value of derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and, if it is, the type of hedge transaction. To the extent certain criteria are met, SFAS 133 permits, but does not require, hedge accounting.

The Group's accounting policies under UK GAAP do not satisfy the criteria for hedge accounting under SFAS 133. The Group does not intend to modify its practice under UK GAAP.

In the normal course of business the Group is a party to derivative financial instruments with off-balance sheet risk, primarily to manage its exposure to fluctuations in foreign currency exchange rates and interest rates, including management of the balance between floating rate and fixed rate debt. The Group also manages certain of its exposures to movements in oil and natural gas prices. In addition, the Group trades derivatives in conjunction with these risk management activities.

All oil price derivatives and all derivatives held for trading are carried on the Group's balance sheet at fair value with changes in that value recognized in earnings of the period. For those derivative instruments, there was no impact of adopting SFAS 133 on the Group's results of operations and financial position, as adjusted to accord with US GAAP. Certain financial derivatives used to manage foreign currency and interest rate risk that qualify for hedge accounting under UK GAAP are marked to market under SFAS 133. For these derivatives, the cumulative effect of adopting SFAS 133 resulted in a pre tax charge to income, as adjusted to accord with US GAAP, of $27 million ($18 million after tax) and a pre tax credit to other comprehensive income of $57 million ($37 million after tax). The net gain included in other comprehensive income as of January 1, 2001 has been reclassified into earnings during 2001. Under US GAAP the fair values of derivative financial instruments are shown as current assets and liabilities as appropriate.

The Group has a number of long-term natural gas contracts, which have been in place for many years. The pricing structure for those contracts is not directly related to the market price of natural gas but to the price of other commodities or indices, such as fuel oil or consumer price indices. SFAS 133 requires these contracts to be marked to market. On the basis of SFAS 133 Implementation Issue C11, the cumulative effect of adopting SFAS 133 for these derivatives resulted in a pre-tax charge to income, as adjusted to accord with US GAAP, at July 1, 2001 of $530 million ($344 million after tax).

Because the Company does not intend to modify its accounting practice to satisfy the criteria for hedge accounting under SFAS 133, the Group's results of operations, as adjusted to accord with US GAAP, will not necessarily be representative of the results it would report if US GAAP were used to prepare the consolidated financial statements of the Group and the Group sought to meet the hedge criteria of SFAS 133 and to apply hedge accounting.

Impact of New US Accounting Standards

In June 2001 the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No.141 'Business Combinations' (SFAS 141) and No. 142 'Goodwill and Other Intangible Assets' (SFAS 142). Under SFAS 141, the pooling of interest method of accounting is no longer permitted; the purchase method must be used for all business combinations initiated after June 30, 2001. SFAS 142, which is effective for accounting periods beginning after December 15, 2001, eliminates the requirement to amortize goodwill and indefinite lived intangible assets. Rather, such assets are subject to periodic impairment testing. Intangible assets that are not deemed to have an indefinite life will continue to be amortized over their estimated useful lives.

It is estimated that elimination of the requirement to amortize goodwill would increase the Group's results of operations, as adjusted to accord with US GAAP, by approximately $1,200 million for the year ended December 31, 2002.

Also in June 2001 the FASB issued Statement of Financial Accounting Standards No. 143 'Accounting for Asset Retirement Obligations' (SFAS 143). SFAS 143 requires companies to record liabilities equal to the fair value of their asset retirement obligations when they are incurred (typically when the asset is installed at the production location). When the liability is initially recorded, companies capitalize an equivalent amount as part of the cost of the asset. Over time the liability is accreted for the change in its present value each period, and the initial capitalized cost is depreciated over the useful life of the related asset. SFAS 143 is effective for accounting periods beginning after June 15, 2002.

The provisions of SFAS 143 are similar to the accounting policy used by the Group in preparing its financial statements under UK GAAP. The Company has not yet determined the effect of adopting SFAS 143 on its results of operations and shareholders' interest as adjusted to accord with US GAAP.

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 144, 'Accounting for the Impairment or Disposal of Long-Lived Assets' (SFAS 144). SFAS 144 retains the requirement to recognize an impairment loss only where the carrying value of a long-lived asset is not recoverable from its undiscounted cash flows and to measure such loss as the difference between the carrying amount and fair value of the asset. SFAS 144, among other things, changes the criteria that have to be met in order to classify an asset as held-for-sale and requires that operating losses from discontinued operations be recognized in the period that the losses are incurred rather than as of the measurement date. SFAS 144 is effective for accounting periods beginning after December 15, 2001.

The Company has not yet determined the effect of adopting SFAS 144 on its results of operations and shareholders' interest as adjusted to accord with US GAAP.

82

ITEM 6 -- DIRECTORS, SENIOR MANAGEMENT AND EMPLOYEES

DIRECTORS AND SENIOR MANAGEMENT

The following lists the 18 directors on the board and the company secretary.

Name	Initially elected or appointed

P D Sutherland................	Non-executive chairman (a)	Chairman since May 199 Director since July 19
Sir Ian Prosser...............	Non-executive deputy chairman (a)(b)(c)	Deputy chairman since February 1999 Director since May 199
The Lord Browne of Madingley..	Executive director (Group chief executive)	September 1991
Dr J G S Buchanan............	Executive director (Chief financial officer)	October 1996
R F Chase....................	Executive director (Deputy group chief executive)	March 1992
W D Ford.....................	Executive director	January 2000
Dr B E Grote.................	Executive director	August 2000
R L Olver....................	Executive director	January 1998
J H Bryan....................	Non-executive director (a)(c)	December 1998
E B Davis, Jr................	Non-executive director (a)(b)(c)	December 1998
Dr D S Julius................	Non-executive director (a)(b)	November 2001
C F Knight...................	Non-executive director (a)(b)	October 1987
F A Maljers..................	Non-executive director (a)(d)	December 1998
Dr W E Massey................	Non-executive director (a)(d)	December 1998
H M P Miles..................	Non-executive director (a)(c)(d)	June 1994
Sir Robin Nicholson..........	Non-executive director (a)(b)	October 1987
M H Wilson...................	Non-executive director (a)(c)	December 1998
Sir Robert Wilson............	Non-executive director (a)(c)(d)	July 1998
J C Hanratty.................	Secretary	October 1994

(a) Member of the Chairman's Committee.

(b) Member of the Remuneration Committee.

(c) Member of the Audit Committee.

(d) Member of the Ethics and Environment Assurance Committee.

Mrs R S Block retired as a non-executive director on April 19, 2001; Dr C S Gibson-Smith retired as an executive director on April 19, 2001; the Lord Wright of Richmond retired as a non-executive director on April 30, 2001, and Mr R J Ferris retired as a non-executive director on June 8, 2001. Dr D S Julius was appointed a non-executive director with effect from November 29, 2001. Mr W D Ford will retire as an executive director on March 31, 2002 and Sir Robert Wilson will not be seeking re-election at the next annual general meeting and will therefore retire as a non-executive director on April 18, 2002.

BP's articles of association require directors who have held office for three years or more since they were appointed or re-elected to retire from office at the Company's annual general meeting, together with directors appointed by the board since the last annual general meeting. Retiring directors may offer themselves for re-election. The Directors retiring and offering themselves for re-election at this year's meeting are Mr J H Bryan, Mr E B Davis Jr, Mr F A Maljers, Dr W E Massey, Mr P D Sutherland and Mr M H Wilson. Dr D S Julius is standing for election by the shareholders.

The biographies of the directors and the secretary are set out below.

P D Sutherland, SC -- Peter Sutherland (55) rejoined BP's board in 1995, having previously been a non-executive director from 1990 to 1993. He was appointed chairman of BP in 1997. He is chairman of Goldman Sachs International and a non-executive director of Telefonaktiebolaget LM Ericsson, Investor AB and The Royal Bank of Scotland Group.

Sir Ian Prosser -- Sir Ian (58) joined BP's board in 1997 and was appointed non-executive deputy chairman in 1999. He is chairman of Six Continents. He is also a non-executive director of GlaxoSmithKline, and chairman of the Executive Committee of the World Travel and Tourism Council.

The Lord Browne of Madingley, FREng -- Lord Browne, formerly Sir John Browne, (54), group chief executive, was appointed an executive director of BP in 1991 and group chief executive in 1995. He is a non-executive director of Goldman Sachs Group and Intel Corporation, and a trustee of the British Museum. He is also vice president and a member of the board of the Prince of Wales Business Leaders Forum.

Dr J G S Buchanan -- John Buchanan (58), chief financial officer, was appointed an executive director of BP in 1996. He is a non-executive director of Boots.

R F Chase -- Rodney Chase (58), deputy group chief executive, was appointed an executive director of BP in 1992. He is a non-executive director of Computer Sciences Corporation and Diageo.

W D Ford -- Doug Ford (58), chief executive, downstream, was appointed an executive director of BP in January 2000. Before the merger of BP and Amoco he had been an executive vice president of Amoco since 1993. He is a non-executive director of USG Corporation and a Trustee of the University of Notre Dame.

Dr B E Grote -- Byron Grote (53), chief executive, chemicals, was appointed an executive director of BP in 2000.

R L Olver -- Dick Olver (55), chief executive, upstream, was appointed an executive director of BP in 1998. He is a non-executive director of Reuters Group.

J H Bryan -- John Bryan (65) joined Amoco's board in 1982. He serves on the boards of Bank One Corporation, General Motors Corporation and Goldman Sachs. He retired as chairman of Sara Lee Corporation in 2001.

E B Davis, Jr -- Erroll B. Davis, Jr (57) joined Amoco's board in 1991. He is chairman, president and chief executive officer of Alliant Energy. He is a non-executive director of PPG Industries and a member of the American Society of Corporate Executives. He serves as a director of the Wisconsin Association of Manufacturers and Commerce, the Edison Electric Institute and the Electric Power Research Institute. He is also chairman of the board of trustees of Carnegie Mellon University.

Dr D S Julius, CBE -- DeAnne Julius (52) joined BP's board in November 2001. She is a non-executive director of the Court of the Bank of England, Lloyds TSB and Serco. From 1997 until June 2001 she was a full time member of the Monetary Policy Committee of the Bank of England.

C F Knight -- Charles Knight (66) joined BP's board in 1987. He is chairman of Emerson Electric and is a non-executive director of Anheuser-Busch, Morgan Stanley Dean Witter, SBC Communications and IBM.

F A Maljers -- Floris Maljers (68) joined Amoco's board in 1994. He is a member of the supervisory boards of SHV Holding and Vendex NV. He is chairman of the supervisory boards of KLM Royal Dutch Airlines, the Amsterdam Concertgebouw NV and Rotterdam School of Management, Erasmus University.

Dr W E Massey -- Walter Massey (63) rejoined Amoco's board in 1993, having previously been a director from 1983 to 1991. He is president of Morehouse College and is a non-executive director of Motorola, Bank of America, McDonald's Corporation, the Mellon Foundation and the Commonwealth Fund. In 2001 he was appointed by President George W. Bush to serve on the President's Council of Advisors on Science and Technology.

H M P Miles, OBE -- Michael Miles (65) joined BP's board in 1994. He is chairman of Johnson Matthey and a non-executive director of ING Baring Holdings and Balfour Beatty.

Sir Robin Nicholson, FREng, FRS -- Sir Robin (67) joined BP's board in 1987. He is a non-executive director of Rolls-Royce.

M H Wilson -- Michael Wilson (64) joined Amoco's board in 1993. He is president and chief executive officer of Brinson Canada and a non-executive director of Manufacturers Life Insurance Company and UBS Asset Management.

Sir Robert Wilson, KCMG -- Sir Robert (58) joined BP's board in 1998. He is chairman of Rio Tinto and a non-executive director of Diageo.

J C Hanratty -- Judith Hanratty (58) joined BP in London in 1986 and was appointed company secretary in 1994. Miss Hanratty reports to the non-executive Chairman and is not part of executive management. She provides senior governance and legal counsel to the Board. She is a nominated member of the Council of Lloyd's of London and of the Lloyd's Market Board. She is also a non-executive director of Partnerships UK and Charles Taylor Consulting, and a member of the Competition Commission and the Takeover Panel. A barrister, she is also the chairman of the Commonwealth Institute and deputy chairman of the College of Law.

COMPENSATION

The Remuneration Committee determines the terms of engagement and remuneration of the executive directors.

Reward Policy

The Remuneration Committee's reward policy reflects its belief in the need to attract, motivate and retain world-class executive talent. The main principles of the policy are:

- Total reward levels should reflect the competitive global market and the committee actively seeks independent advice on this.

- The majority of the total reward is linked to achievement of demanding performance targets as shown in the descriptions of the elements of remuneration. By way of illustration, in 2001 over three-quarters of the executive directors' remuneration was performance-based.

-- Executive directors should share the interests of shareholders in making BP successful to the benefit of all shareholders. This is achieved through setting robust performance targets based on measures of shareholders' interests and through the committee's policy for executive directors to hold a significant shareholding in the company, currently equivalent to 5 times their base salary.

-- The performance targets in the Executive Directors' Long Term Incentive Plan must encompass demanding comparisons of BP's shareholder returns and earnings with those of other companies in its own industry and in other sectors as well.

-- The committee continually assesses whether the reward structure is achieving its objectives. In late 2001, it reviewed the existing remuneration of all executive directors relative to a comparator group of global companies. After taking independent external advice the committee agreed that there should be no major changes in the framework for total reward. In 2002 it will be reviewing long-term incentive awards.

-- In 2002 base salaries for the executive directors will be increased by less than 10%, in line with similar global companies.

-- All UK executive directors appointed after 1996 should hold a contract of service with a maximum of a one-year period of notice.

Elements of remuneration

An increasing share of executive directors' pay is performance-related with the majority now based on long-term performance. The more senior the executive, the greater the proportion of 'at risk' remuneration.

There are three elements of executive remuneration: performance-based components -- long-term; performance-based components -- short-term; and fixed components. These are described in the following paragraphs.

Performance-based Components -- Long-term

The Executive Directors' Long Term Incentive Plan (EDLTIP) was adopted by shareholders at the Annual General Meeting in April 2000 to provide long-term incentives specifically for the executive directors.

EDLTIP has three elements:

Share Element

The share element compares BP's performance against 'oil majors' over three years, on a rolling basis. This has been assessed in terms of a three-year shareholder return against the market (SHRAM), return on average capital employed (ROACE) and earnings per share (EPS) growth.

85

The committee reviews and approves annually the performance measures and the comparator companies. The comparator group of companies used for the SHRAM performance condition in the share element has been reduced so much by industry consolidation that the committee has decided for the 2002-2004 Plan to change to the FTSE All World Oil and Gas index weighted by market capitalization. The committee is satisfied that this change does not make the performance targets of the plan less demanding.

Performance units are granted at the beginning of the period and converted into an award of shares at the end of the three-year period, depending on performance. It is a condition for any such award that the individual holds shares equivalent to at least five times base salary.

Shares awarded are then held in trust for three years before they are released to the individual. This gives the executive directors a six-year incentive structure, and ensures their interests are aligned with those of shareholders.

Share Option Element

The share option element reflects BP's performance relative to a wider selection of global companies. The committee will take into account BP's total shareholder return (TSR) compared with the TSR for the FTSE Global 100 group of companies over the three years preceding the grant.

Cash Element

The cash element allows the Remuneration Committee to grant cash rather than share-based incentives in exceptional circumstances. This element was not used in 2001.

Performance-based Components -- Short-term

Annual Bonus

The short-term performance-related component of executive directors' remuneration consists of an annual bonus. The Remuneration Committee reviews and sets bonus targets and level of eligibility annually. The target level is 100% of base salary (except for Lord Browne who has a 110% target). There is a stretch level of 150% of base salary for substantially exceeding targets.

Targets consist of a mix of demanding financial targets and other leadership objectives covering areas such as people, safety, environment and organization.

Fixed Components

Salary

Fixed sum, payable monthly in cash. Salaries are reviewed periodically in line with global markets. The appropriate survey groups are defined and analysed by a leading remuneration consultancy.

Pension

Executive directors are eligible to participate in the appropriate pension schemes applicable in their home countries.

Benefits and Other Share Schemes

Executive directors are eligible to participate in regular employee benefit plans, including health and life insurance and in all-employee share schemes and savings plans as applicable in their home countries.

Resettlement Allowance

Expatriates may receive a resettlement allowance for a limited period.

2001 Remuneration for Executive Directors

The Group achieved a strong result in 2001, leading the industry in ROACE and EPS growth. SHRAM results placed BP second in the group of comparable oil companies. Cumulative savings on the combined cost structure of the enlarged Group reached their target of $5.8 billion pre-tax, compared with a 1998 base. There was excellent progress on leadership targets such as people, safety, environment and organization.

	Long term remuneration			Annual		
Summary of remuneration	Performance units granted under 2001-2003 share element(a)	Shares awarded under 1999-2001 share element(b)	Share option grants(c)	2001 annual performance bonus	Salary	Ben and emolu
						($ tho
The Lord Browne of Madingley	415,000	472,500	1,269,843	2,566	1,728	
Dr J G S Buchanan...........	165,000	280,000	253,971	933	691	
R F Chase...................	205,000	315,000	312,171	1,147	850	
W D Ford....................	170,000	175,000	261,036	972	720	
Dr B E Grote................	155,000	175,000	241,092	898	665	
R L Olver...................	170,000	252,000	260,319	956	708	
Director leaving the board in 2001						
Dr C S Gibson-Smith.........	--	252,000	--	773	497	

The table above represents remuneration received by executive directors in the 2001 financial year, with the exception of the 2001 annual bonus which was earned in 2001 but paid in 2002. A conversion rate of (pound)1 = $1.44 has been used for 2001, (pound)1 = $1.51 for 2000.

(a) Performance units granted under the 2001-2003 LTPP are converted to shares at the end of the performance period. Maximum of two shares per performance unit.

(b) Gross award of shares. Sufficient shares are sold to pay for tax applicable. Remaining shares are held in trust until 2005 when they are released to the individual.

(c) Options granted in February 2001 have a grant price of (pound)5.67 per share. Mr Ford and Dr Grote hold ADSs; the above numbers and prices reflect calculated equivalents.

(d) Includes resettlement allowances for Mr Ford and Dr Grote of $440,000 and $300,000 respectively.

(e) Includes pay in lieu of notice for Dr Gibson-Smith of $386,000.

Long-term performance-based components

Long Term Performance Plan (LTPP) and Share Element

The LTPP award for the 1999-2001 performance period was made in February 2002 based on results achieved. The shares then have a minimum three years' retention in trust and no shares will be released until the director has a personal holding of BP shares equivalent to five times base salary.

Performance period of Plan	1998-2000		1999-2001		2000-2002
Year of award	2001		2002		2003
Performance measures (a)	SHRAM		SHRAM, EPS and ROACE		SHRAM, EPS and ROACE
	Actual award		Expected award (c)		Maximum award
	(shares)	(value)(b)	(shares)	(value)(d)	(shares)
	($ thousand)		($ thousand)		
Current executive directors					
The Lord Browne of Madingley.	532,600	4,357	472,500	3,708	560,000
Dr J G S Buchanan............	-- (e)	--	280,000	2,197	308,000
R F Chase....................	339,000	2,773	315,000	2,472	348,000
W D Ford.....................	--	--	175,000	1,373	264,000
Dr B E Grote.................	247,000	2,020	175,000	1,373	170,000
R L Olver....................	297,400	2,433	252,000	1,978	294,000
Former executive directors					
Dr C S Gibson-Smith..........	297,400	2,433	252,000	1,978	280,000
B K Sanderson................	339,000	2,773	280,000	2,197	--
H L Fuller...................	--	--	472,500	3,708	--

(a) Shareholder return against the market (SHRAM), earnings per share (EPS), return on average capital employed (ROACE). In order to assess current performance on a consistent basis with past performance and a basis comparable with major competitors, EPS and ROACE in 2000 and going forward will be calculated on a pro forma basis, adjusted for special items. The pro forma basis excludes acquisition amortization and for operating capital employed it excludes the fixed asset revaluation adjustment and goodwill resulting from the ARCO and Burmah Castrol acquisitions. Acquisition amortization is the depreciation relating to the fixed asset revaluation adjustment and amortization of goodwill consequent upon these acquisitions. Special items are non-recurring charges and credits that are not classified as exceptional under UK GAAP.

(b) Based on average market price on date of award ((pound)5.68/$8.18 at(pound)1 = $1.44).

(c) The Remuneration Committee's current expectation based on assessed performance and other terms of the Plan. The calculations for the 1999-2001 Plan include the share split.

(d) Based on mid-market price of BP shares on February 12, 2002 ((pound)5.45/$7.85 at(pound)1 = $1.44).

(e) Dr Buchanan elected to defer until 2004 the determination of whether an award should be made for this period.

For the 1998-2000 LTPP BP's performance was assessed in terms of three-year shareholder return against the market (SHRAM) in relation to the following companies: Chevron, ExxonMobil, Shell and Texaco. BP came first in the 1998-2000 Plan, and the Remuneration Committee made the maximum award of shares to executive directors in 2001.

For the 1999-2001 Plan BP's SHRAM again exceeded ChevronTexaco, ExxonMobil and TotalFinaElf, but came second to Shell.

The Remuneration Committee has also considered profitability and growth targets for the 1999-2001 Plan, i.e. return on average capital employed (ROACE) and earnings per share (EPS) growth. On both measures BP came first in assessing performance against the same oil companies.

Based on an initial performance assessment of 175 points out of 200, the committee expects to make an award of shares to executive directors as set out in the 1999-2001 column of the above LTPP table.

Share Option Element and Other Option Schemes

Option grants in 2001 were made taking into consideration the ranking of the Company's total shareholder return (TSR) against the TSR of the FTSE Global 100 group of companies over the three-year period from January 1, 1998. Options granted vest over three years (one-third each after one, two and three years respectively) and have a life of seven years after grant. Executive directors who retire after January 1, 2002 may retain vested options for this period.

	Option type	At Jan 1, 2001	Granted	Exercised	At Dec 31, 2001	Option price	Mar price date exerc
The Lord Brown of Madingley	SAYE	5,968	--	--	5,968	(pound)2.89	
	EDLTIP	408,522	--	--	408,522	(pound)5.99	
	EDLTIP	--	1,269,843	--	1,269,843	(pound)5.67	
Dr J G S Buchanan..........	SAYE	2,980	--	2,980	--	(pound)2.32	(pound)5
	SAYE	1,856	--	--	1,856	(pound)3.72	
	SAYE	750	--	--	750	(pound)4.50	
	SAYE	--	1,320	--	1,320	(pound)5.11	
	EDLTIP	75,189	--	--	75,189	(pound)5.99	
	EDLTIP	--	253,971	--	253,971	(pound)5.67	
R F Chase.................	SAYE	3,388	--	--	3,388	(pound)4.98	
	EDLTIP	85,215	--	--	85,215	(pound)5.99	
	EDLTIP	--	312,171	--	312,171	(pound)5.67	
W D Ford(a)...............	NRSO	105,866	--	--	105,866	$20.80	
	NRSO	119,100	--	--	119,100	$23.69	
	NRSO	132,332	--	--	132,332	$27.68	
	NRSO	132,332	--	--	132,332	$34.08	
	NRSO	132,332	--	--	132,332	$32.92	
	BPA	54,712	--	--	54,712	$53.90	

	BPA	38,750	--	--	38,750	$48.94	
	EDLTIP	--	43,506	--	43,506	$49.65	
Dr B E Grote(a)..........	SAR	40,000	--	--	40,000	$13.63	
	SAR	40,800	--	--	40,800	$16.63	
	SAR	35,600	--	--	35,600	$19.16	
	SAR	35,200	--	--	35,200	$25.27	
	SAR	40,000	--	--	40,000	$33.34	
	BPA	10,404	--	--	10,404	$53.90	
	BPA	12,600	--	--	12,600	$48.94	
	EDLTIP	--	40,182	--	40,182	$49.65	
R L Olver................	SAYE	4,470	--	4,470	--	(pound)2.32	(pound)5
	SAYE	2,386	--	--	2,386	(pound)2.89	
	SAYE	--	1,137	--	1,137	(pound)5.11	
	EDLTIP	71,847	--	--	71,847	(pound)5.99	
	EDLTIP	--	260,319	--	260,319	(pound)5.67	
Director leaving the board in 2001							
Dr C S Gibson-Smith.......	SAYE	2,154	--	--	2,154(b)	(pound)4.50	
	EDLTIP	68,505	--	--	68,505(b)	(pound)5.99	

EDLTIP -- Executive Directors' Long Term Incentive Plan adopted by shareholders in April 2000 as described under Compensation -- Performance-based Components -- Long-term.

BPA -- BP share option plan which applied to US executive directors prior to the adoption of the EDLTIP.

NRSO -- Amoco Non-Restricted Stock Option which applied to Mr Ford as an employee of Amoco.

SAR -- Stock Appreciation Rights under BP America Inc. Share Appreciation Plan.

SAYE -- Save as You Earn employee share option scheme.

(a) Numbers shown are ADSs under option. One ADS is equivalent to six ordinary shares.

(b) At retirement on April 19, 2001.

Short-term performance-based components

Executive directors' annual bonus awards for 2001 were based on a mix of financial targets and leadership objectives established at the beginning of the year. Assessment of all the targets showed that, compared with a target performance of 100 points, 135 points were achieved, resulting in bonus awards as shown in the summary of remuneration under the heading Compensation -- Elements of Remuneration.

Salaries

Each year the committee receives independent advice on competitive global salary markets for the group chief executive and for the other executive directors. Taking into account this advice and the fact that base salaries had not previously been increased since October 1999, the committee decided to increase Lord Browne's salary by 47% and the other executive directors' salaries by an average of 15% for 2001.

Pensions

Pension entitlement-- UK executive directors	Service at December 31, 2001	Accrued benefit at December 31, 2001	Additional pension earned during the year ended December 31, 2001 (b)	Additional pension earned during the year ended December 31, 2000 (b)
		($ thousand)(a)	($ thousand)(a)	($ thousand)(a)
The Lord Browne of Madingley	35 yrs	1,152	346	(15)
Dr J G S Buchanan...........	32 yrs	461	29	15
R F Chase...................	37 yrs	566	62	(9)
Dr C S Gibson-Smith (c).....	30 yrs	420	48	14
R L Olver...................	28 yrs	470	68	14

(a) An exchange rate of(pound)1 = $1.44 has been used for 2001,(pound)1 = $1.51 for 2000.

(b) Excludes the impact of inflation.

(c) Figures shown at date ceased being a director (April 19, 2001).

UK directors are members of the BP Pension Scheme (the Scheme). The Scheme offers Inland Revenue-approved retirement benefits based on final salary. It is the principal section of the BP Pension Fund (the Fund), the latter being set up under trust deed. Company contributions to the Fund are made on the advice of the actuary appointed by the Trustee. No company contributions were made during 2001.

Scheme members' core benefits are non-contributory. They include a pension accrual of 1/60th of basic salary for each year of service, subject to a maximum of two-thirds of final basic salary; a lump-sum death-in-service benefit of three times salary; and a dependant's benefit of two-thirds of the member's pension. The Scheme pension is not integrated with state pension benefits.

Normal retirement age is 60, but Scheme members who have 30 or more years' pensionable service at age 55 can elect to retire early without an actuarial reduction being applied to their pension.

Pensions payable from the Fund are guaranteed to be increased annually in line with changes to the Retail Prices Index, up to a maximum of 5% a year.

Directors accrue pension on a non-contributory basis at the enhanced rate of 2/60ths of their final salary for each year of service as executive directors (up to the same two-thirds limit). None of the directors is affected by the pensionable earnings cap.

			Additional pension earned	Additional pension earned

Pension entitlement-- US executive directors	Service at December 31, 2001	Accrued benefit at December 31, 2001 ($ thousand)	during the year ended December 31, 2001 ($ thousand)	during the year ended December 31, 2000 ($ thousand)
W D Ford....................	31 yrs	504(a)	128(a)	67
Dr B E Grote................	22 yrs	83	14	10

(a) Includes a temporary annuity of $7,123 which is payable until age 62.

US directors participate in the BP Retirement Accumulation Plan (the US Plan). Under the US Plan, the amount of the annuity they are eligible to receive on a single-life basis is determined using a cash balance formula. The US Plan was established in 2000; it superseded earlier Group pension and cash balance plans. However, those employees who satisfied certain age and service conditions at the date of transition to the US Plan were provided with minimum benefits equal to those they would have earned under their previous pension arrangements. In line with US tax regulations, benefits are provided through a combination of tax qualified and restoration/non-qualified plans, as appropriate.

Under these 'grandfathering' arrangements, the annuity benefit formula (which includes a percentage of US Social Security benefits) is calculated at 1.67% times years of participation times average annual earnings. These earnings are determined by taking separately the three highest consecutive calendar years' earnings from salary and the three highest consecutive calendar years' bonus awards during the 10 years preceding retirement. The maximum annuity is 60% of such average earnings.

Normal pensionable age is 65. No actuarial reduction is applied to the pension if it is paid from age 60; however, a reduction of 5% a year is applied if paid between ages 50 and 59.

Mr Ford is subject to the 'grandfathering' arrangements and his figures have been disclosed on this basis.

Dr Grote is not subject to the 'grandfathering' arrangements. His benefit is determined by the cash balance formula, under which each year of service accrues a monetary credit in a current account. The credit is based on a sliding scale, referencing age and service, and is subject to a minimum of 4% and a maximum of 11% of eligible pay. The account balance earns interest on a monthly basis.

Executive Directors' Shareholdings

Executive directors' interests in BP ordinary shares or calculated equivalents	At December 31, 2001	At January 1, 2001 or on appointment	Change i directo interests fr December 31, 20 to March 26, 20

Current directors			
The Lord Browne of Madingley...........	1,392,184(a)	1,069,445(a)	283,5
Dr J G S Buchanan.....................	723,149	721,312	168,2
R F Chase.............................	794,745	709,325	189,2
W D Ford..............................	333,139(b)	311,358(b)	170,6
Dr B E Grote..........................	595,845(b)	431,598(b)	105,0
R L Olver.............................	585,852	421,910	151,5

	On retirement	At January 1, 2001
Director leaving the board in 2001		
Dr C S Gibson-Smith...................	671,812(c)	491,395

(a) Includes 50,368 ordinary shares held as ADSs throughout 2001. One ADS is equivalent to six ordinary shares.

(b) Held as ADSs.

(c) On retirement on April 19, 2001.

In disclosing the above interests to the company under the Companies Act 1985, directors did not distinguish their beneficial and non-beneficial interests.

No director has any interest in the preference shares or debentures of the company, or in the shares or loan stock of any subsidiary company.

By operation of law, the executive directors who participate in certain all-employee SAYE option schemes are regarded as having an interest in such shares of the company held from time to time by BP QUEST Company Limited, which facilitates the operation of such schemes. The individual interests of executive directors in share-based remuneration are set out on page 87 of this report.

Service Contracts

All executive directors appointed since 1996 hold a contract of service which includes a period of notice of one year or less, except Mr Ford. Lord Browne and Mr Chase were appointed prior to 1996 and have contracts with a two-year notice period. The board does not consider it in shareholders' interests to renegotiate these contracts.

Mr Ford has resigned from the board of BP p.l.c. with effect from March 31, 2002, at which time his secondment will end. His underlying US employment agreement with BP Corporation North America has a two-month notice period. If his contract is terminated by BP Corporation North America without cause, it is required to pay him $1 million per annum (pro rated for part years) for each year between the date of severance and January 21, 2004.

Remuneration of Non-Executive Directors

The articles of association provide that the remuneration paid to non-executive directors is to be determined by the board within the limits set by the shareholders. Non-executive directors do not have service contracts with the Company. Their fees are fixed and paid in pounds sterling. For conformity, these are also reported in US dollars.

During 2001, the non-executive chairman received a fee of (pound) 280,000 ($403,000) and the non-executive deputy chairman a fee of (pound) 85,000 ($122,000). The non-executive directors received an annual fee of (pound) 45,000 ($65,000), plus an allowance of (pound) 3,000 ($4,000) for each occasion on which a director travels across the Atlantic for a board meeting or committee meeting. During 2001, the board met nine times, six times in the UK and three times in the USA. Committee meetings are held in conjunction with board meetings whenever feasible. Details of individual fees and allowances are set out in the table below.

Current directors	Year ended December 31, 2001(a)		Year ended December 31, 2000(b)	
	(thousands)			
	(pound)	$	(pound)	$
J H Bryan	57	82	58	88
E B Davis, Jr	57	82	58	88
Dr D S Julius	4	6	--	--
C F Knight	54	78	55	83
F A Maljers	54	78	43	65
Dr W E Massey	65	94	55	83
H M P Miles (c)	54	78	46	69
Sir Robin Nicholson (d)	57	83	46	69
Sir Ian Prosser	85	122	80	121
PD Sutherland	280	403	160	242(e)
M H Wilson	60	86	58	88
Sir Robert Wilson	51	73	46	69
	878	1,265	705	1,065
Directors leaving the board in 2001 (f)				
R S Block	17	24	49	74
R J Ferris	32	45	52	79
The Lord Wright of Richmond (g)	20	28	46	69

(a) Sterling payments converted at the average 2001 exchange rate of(pound)1 = $1.44.

(b) Sterling payments converted at the average 2000 exchange rate of(pound)1 = $1.51.

(c) Also received (pound) 300 ($432) for serving as a director of BP Pension Trustees Limited in 2001.

(d) Also received (pound) 20,000 per year ($30,200 at 2000 rate; $28,800 at 2001 rate) for serving on the Technology Advisory Council.

(e) Also received other benefits of (pound) 1,518 ($2,292 at 2000 rate).

(f) In addition to their remuneration, certain payments in lieu of pension were made or released to non-executive directors leaving the board during 2001, totalling (pound) 487,853 ($702,508). These included meeting obligations entered into by Amoco Corporation with respect to former Amoco non-executive directors. Details of these are given in Item 18 -- Financial Statements -- Note 35.

(g) Also received (pound) 1,200 ($1,812) for serving as a director of BP Pension Trustees Limited in 2000 and (pound) 300 ($432) in 2001.

BOARD PRACTICES

Directors' Terms of Office	Date of expiration of current term of office	Period during which the director has served in this office (from appointment to April 2002)
The Lord Browne of Madingley..............	April 2004	10 years 7 months
J H Bryan (a).............................	April 2002	3 years 4 months
Dr J G S Buchanan.........................	April 2003	5 years 7 months
Mr R F Chase..............................	April 2003	10 years 1 month
E B Davis, Jr (a).........................	April 2002	3 years 4 months
W D Ford..................................	Retires March 2002	2 years 4 months
Dr B E Grote..............................	April 2004	1 year 9 months
Dr D S Julius.............................	April 2002	5 months
C F Knight................................	April 2003	14 years 7 months
F A Maljers (a)...........................	April 2002	3 years 4 months
Dr W E Massey (a).........................	April 2002	3 years 4 months
H M P Miles...............................	April 2004	7 years 11 months
Sir Robin Nicholson......................	April 2004	14 years 7 months
R L Olver.................................	April 2004	4 years 4 months
Sir Ian Prosser..........................	April 2004	5 years
P D Sutherland............................	April 2002	6 years 8 months
M H Wilson (a)............................	April 2002	3 years 4 months
Sir Robert Wilson........................	Retires April 2002	3 years 9 months

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(a) Does not include service on the board of Amoco Corporation.

Directors' Service Contracts Providing for Benefits upon Termination of Employment

Non-executive directors do not have service contracts with the Company; they are not employees of the Company. Non-executive directors are not entitled to any benefits on termination of office. Executive directors are employees of the Company or one of its subsidiaries under a variety of contracts of service. The standard contract of service for executive directors provides for one year's notice to be given of termination of the contract or payment of one year's salary in lieu of notice. There are three exceptions to this standard contract:

The Lord Browne of Madingley, Mr Chase and Mr Ford. Lord Browne and Mr Chase have contracts that provide for two year's notice of termination. Mr Ford has resigned from the board of BP p.l.c. with effect from March 31, 2002, at which time his secondment will end. His underlying US employment agreement with BP Corporation North America has a two-month notice period. If his contract is terminated by BP Corporation North America without cause, it is required to pay him $1 million per annum (pro rated for part years) for each year between the date of severance and January 21, 2004.

Corporate Governance Statement

General

The board's governance policies (adopted in 1997) regulate its relationship with shareholders, the conduct of board affairs and its relationship with the group chief executive. The policies recognize that the board has a separate and unique role as the link in the chain of authority between the shareholders and the group chief executive. In addition, they acknowledge the dual role played by the group chief executive and executive directors as both members of the board and leaders of the executive management. The policies therefore require a majority of the board to be composed of non-executive directors and to delegate all aspects of the relationship between the board and the group chief executive to the non-executive directors. The policies also require the chairman and deputy chairman to be non-executive directors; throughout 2001 the posts were held by Mr Sutherland and Sir Ian Prosser respectively. Sir Ian Prosser acts as the senior independent non-executive director as required by the UK Combined Code on Corporate Governance. Finally, the company secretary reports to the non-executive chairman and is not part of the executive management.

Relationship with Shareholders

The policies emphasize the importance of the relationship between the board and the shareholders. In them, the board acknowledges that its role is to represent and promote the interests of shareholders and that it is accountable to shareholders for the performance and activities of the Group (including, for example, the system of internal control and the review of its effectiveness). The board is required to be proactive in obtaining an understanding of shareholder preferences and to evaluate systematically the economic, social, environmental and ethical matters that may influence or affect the interests of its shareholders. These interests are represented and promoted by the board through exercising its policy-making and monitoring functions. As a result, shareholder interests lie at the heart of the goals established by the board for the Company.

The board is accountable to shareholders in a variety of ways. Directors are required to stand for re-election every three years to ensure that shareholders have a regular opportunity to reassess the composition of the board. New directors are subject to election at the first opportunity following their appointment. Names submitted to shareholders for election in 2001 were accompanied by biographical details.

The board makes use of a number of formal channels of communication to account to shareholders for the performance of the Company. These include the Annual Report and Accounts, the Form 20-F filed annually with the US Securities and Exchange Commission, quarterly announcements made through stock exchanges on which the shares are listed and the annual general meeting of shareholders.

Given the size and geographical diversity of BP's shareholder base, the opportunities for shareholder interaction at the annual general meeting are limited. However, the chairmen of the Audit Committee, Remuneration Committee and all other committee chairmen were present at the 2001 annual general meeting to answer questions along with the chairman. Shareholder-requisitioned resolutions have been moved before the last two annual general meetings. All proxy votes at shareholder meetings are counted since votes on all matters except procedural issues are taken by way of a poll. BP has also pioneered the use of electronic communications to facilitate the exercise of shareholder voting rights. In addition to the e-voting facility available to shareholders for the first time in 2001, presentations given at appropriate intervals to representatives of the investment community in both the UK and the USA are available simultaneously to all shareholders by live internet broadcast or open conference call.

Board Process

The board has laid down rules for its own activities in a board process policy that covers the conduct of members at meetings; the cycle of board activities and the setting of agendas; the provision of information to the board; board officers and their roles; board committees, their tasks and composition; qualifications for board membership and the process of the Nomination Committee; the remuneration of non-executive directors; the appointment and role of the company secretary; the process for directors to obtain independent advice and the assessment of the board's performance. The board process policy places responsibility for implementation of this policy, including training of directors, on the chairman.

The policy recognizes that the board's capacity, as a group, is limited. The board therefore reserves to itself the making of broad policy decisions, delegating more detailed considerations involved in meeting its stated requirements either to board committees and officers (in the case of its own processes) or to the group chief executive (in the case of the management of the company's business activity). The policy allocates the tasks of monitoring executive actions and assessing reward to the following committees:

-- Chairman's Committee (all non-executive directors) -- organization and succession planning and overall performance assessment.

-- Audit Committee (four to six non-executive directors) -- monitoring all reporting, accounting, control and the financial aspects of the executive management's activities. Further details are given below.

-- Ethics and Environment Assurance Committee (four to six non-executive directors) -- monitoring the non-financial aspects of the executive management's activities.

-- Remuneration Committee (four to six non-executive directors) -- determining performance contracts and targets and the structure of the rewards for the group chief executive and the executive directors. Further details are set forth below.

In addition, there is a Nomination Committee, which comprises the non-executive chairman, the group chief executive and three non-executive directors selected from time to time as required.

The qualification for membership of the board includes a requirement that non-executive directors be free from any relationship with the executive management of the company that could materially interfere with the exercise of their independent judgement. In the board's view, all non-executive directors fulfil this requirement.

In carrying out its work, the board has to exercise judgement about how best to further the interests of shareholders. Given the uncertainties inherent in the future of business activity, the board seeks to maximize the expected value of shareholders' interest in the Group, not to eliminate the possibility of any adverse outcomes for shareholders.

Board/Executive Relationship

The board/executive relationship policy sets out how the board delegates authority to the group chief executive and the extent of that authority. In its goals policy, the board states the long-term outcome it expects the group chief executive to deliver. The restrictions on the manner in which the group chief executive may achieve the required results are set out in the executive limitations policy, which addresses ethics, health, safety, the environment, financial distress, internal control, risk preferences, treatment of employees and political considerations. On all these matters, the board's role is to set general policy and to monitor the implementation of that policy by the group chief executive.

The group chief executive explains how he intends to deliver the required outcome in annual and medium-term plans, the former of which include a comprehensive assessment of the risks to delivery. Progress towards the expected outcome is set out in a monthly report that covers actual results and a forecast of results for the current year. The board reviews this report at each meeting.

The board/executive relationship policy also sets out how the group chief executive's performance will be monitored and recognizes that, in the multitude of changing circumstances, judgement is always involved. The group chief executive is obliged through dialogue and systematic review to discuss with the board all material matters currently or prospectively affecting the company and its performance and all strategic projects or developments. This specifically includes any materially under-performing business activities and actions that breach the executive limitations policy. It also includes social, environmental and ethical considerations. This dialogue is a key feature of the board/executive relationship. Between board meetings the chairman has responsibility for ensuring the integrity and effectiveness of the board/executive relationship. The systems set out in the board/executive relationship policy are designed to manage rather than eliminate the risk of failure to achieve the board goals policy or observe the executive limitations policy. They provide reasonable, not absolute, assurance against material misstatement or loss.

Audit Committee

The committee is comprised of six non-executive directors: Sir Ian Prosser (Chairman), Mr Bryan, Mr Davis Jr, Mr Miles, Mr Wilson and Sir Robert Wilson. The Secretary of the Audit Committee, Miss Judith Hanratty (Company Secretary) is independent of the executive management of the Company and reports to the non-executive chairman.

The tasks given to the Audit Committee by the Board Governance Policies are:

-- To monitor systematically and obtain assurance that the legally required standards of disclosure are being fully and fairly observed.

-- To review all prospectuses, information and offering memoranda and other documents to be placed before shareholders and make recommendations to the board about their adoption and publication.

-- To review all annual, quarterly and similar reports to shareholders and make recommendations to the board about their adoption and publication.

-- To monitor systematically and obtain assurance that the Executive Limitations set out in the Board Governance Policies relating to financial matters are being observed.

The Committee met seven times in 2001.

Remuneration Committee

The Remuneration Committee decides the remuneration policy and sets the terms of engagement and total rewards of the executive directors. The committee agrees each executive director's service contract, salary, targets and bonus scheme, and the grants of options and performance units under the Executive Directors' Long Term Incentive Plan.

Its members are all independent non-executive directors. The current membership is Sir Robin Nicholson (chairman), Mr Knight, Sir Ian Prosser, Mr Davis and Dr Julius. During the year Mrs Block, Mr Ferris and the Lord Wright of Richmond retired. Like other directors, each member of the committee is subject to periodic re-election every three years.

They have no personal financial interest, other than as shareholders, in the committee's decisions. They have no conflicts of interest arising from cross-directorships with the executive directors nor from being involved in the day-to-day business of the company.

The committee met five times in the period under review. The committee consults the group chief executive on matters relating to other executive directors who report to him. He is not present when matters affecting his own remuneration are considered. The chairman of the board also attends meetings when appropriate.

The committee is serviced independently of the executive management and actively seeks advice from external professional consultants. In its constitution and operation it complies with the 'Principles of Good Governance and Code of Best Practice' set out by the Listing Rules of the Financial Services Authority (FSA). Ernst & Young LLP have confirmed that the scope of their report on the accounts covers the disclosures contained in this report that are specified for audit by the Listing Rules.

EMPLOYEES

	UK	Rest of Europe	USA	Rest of World	Total
Number of employees at December 31, 2001					
Exploration and Production............	3,700	800	5,500	6,550	16,550
Gas and Power.........................	600	150	600	600	1,950

Refining and Marketing	10,500	16,250	26,600	11,250	64,600
Chemicals	3,450	6,250	6,700	5,550	21,950
Other businesses and corporate	1,400	550	2,100	1,050	5,100
	19,650	24,000	41,500	25,000	110,150
2000					
Exploration and Production	3,300	700	5,900	6,100	16,000
Gas and Power	500	100	700	300	1,600
Refining and Marketing	10,100	16,800	27,000	13,200	67,100
Chemicals	3,700	4,500	7,900	1,500	17,600
Other businesses and corporate	1,300	400	2,500	700	4,900
	18,900	22,500	44,000	21,800	107,200
1999					
Exploration and Production	3,700	1,150	2,800	4,850	12,500
Gas and Power	450	50	600	300	1,400
Refining and Marketing	9,000	11,150	17,500	7,000	44,650
Chemicals	3,950	4,700	8,100	1,950	18,700
Other businesses and corporate	1,150	300	1,150	550	3,150
	18,250	17,350	30,150	14,650	80,400

Following the merger of BP and Amoco on December 31, 1998, some 19,000 employees have left the Group through severance or outsourcing arrangements. Of this total approximately 16,000 employees left in 1999. The acquisition of ARCO and Burmah Castrol during 2000 brought approximately 25,000 additional employees to the Group, of which some 3,000 have left through integration and rationalization activities. Employee numbers increased slightly during 2001, as increases primarily related to the acquisition of Bayer's 50% interest in Erdoelchemie, the Solvay transaction and the Burmah Castrol chemicals businesses previously held for sale, were partly offset by downstream rationalization and a further decrease in former ARCO employees.

SHARE OWNERSHIP

Directors

As at March 26, 2002 the following directors of BP p.l.c. held interests in BP ordinary shares of 25 cents each or their calculated equivalent as set out below:

The Lord Browne of Madingley	1,675,684
Dr J G S Buchanan	891,391
R F Chase	983,949
W D Ford	503,826
Dr B E Grote	700,845
R L Olver	737,378
J H Bryan	98,760
E B Davis, Jr.	62,695
Dr D S Julius	2,000
C F Knight	30,247
F A Maljers	33,492
Dr W E Massey	47,378
H M P Miles	9,445
Sir Robin Nicholson	3,643

Sir Ian Prosser..............	2,826
P D Sutherland...............	7,079
M H Wilson...................	43,200
Sir Robert Wilson............	5,478

As at March 26, 2002, the following directors of BP p.l.c. held options under the BP Group share option schemes for ordinary shares or their calculated equivalent as set out below:

The Lord Browne of Madingley..	3,032,365
Dr J G S Buchanan............	333,086
R F Chase....................	400,774
W D Ford.....................	4,553,580
Dr B E Grote.................	728,154(a)
R L Olver....................	706,645

(a) In addition to the above, Dr Grote holds 191,600 Stock Appreciation Rights (equivalent to 1,149,600 BP ordinary shares)

Additional details regarding the options granted, including exercise price and expiry dates, are found in this item under the heading 'Compensation -- Share Option Element and Other Option Schemes'.

Employee Share Schemes

BP offers most of its employees the opportunity to acquire a shareholding in the company through savings-related and matching share plan arrangements. Such arrangements are now in place in over 60 countries. BP also uses long-term performance plans (see Item 18 -- Financial Statements -- Note 34) and the granting of share options as elements of remuneration for executive directors and senior employees.

During 2001 share options were granted to the executive directors under the EDLTIP and to certain other categories of employees. For these options the option price was the market price on the grant date. The options granted to executive directors reflect BP's performance in terms of TSR, that is, share price increase with all dividends reinvested, relative to the FTSE global 100 group of companies over the three years preceding the grant. The options are exercisable between the third and the tenth anniversary of the date of grant.

Share options were also granted in 2001 under the BP Share Option Plan to certain categories of employees. Subject to certain vesting requirements the options are exercisable between the third and tenth anniversaries of the date of grant. There are no performance conditions attaching to the options granted during the year.

Under the BP ShareSave Plan (a savings-related share option scheme) employees save monthly over a three- or five-year period towards the purchase of shares at a price fixed when the option is granted. The option price is usually set at a 20% discount to the market price at the time of grant. The option must be exercised within six months of maturity of the savings contract; otherwise it lapses. The plan is run in the UK and a small number of other countries.

For the BP ShareMatch Plan, BP matches employees' own contributions of shares, up to a predetermined limit. The shares are then held in trust for a defined minimum period. The plan is run in the UK and in over 40 other countries.

The Company sponsors a number of savings plans covering most US employees. Under these plans, employees may contribute up to 18% of their salary subject to certain regulatory limits. Typically the employee receives a dollar-for-dollar Company matched contribution for the first 7% of eligible pay contributed to most of these plans on a before-tax or after-tax basis, or a combination of both. The precise arrangement depends on the individual's employment contract. Company contributions are initially invested in BP ADS funds, but employees may transfer those amounts and may invest their own contributions in more than 200 investment options. The Company's contributions to savings plans during the year were $125 million ($101 million).

An Employee Share Ownership Plan (ESOP) was established in 1997 to acquire BP shares to satisfy future requirements of certain employee share plans. The Company provides funding to the ESOP. The assets and liabilities of the ESOP are recognized as assets and liabilities of the Company within the accounts. The ESOP has waived its rights to dividends.

During 2001 the ESOP released 11,508,754 shares (2000, 9,412,931 shares) for the matching share plans. The cost of shares released for these plans has been charged in these accounts. At December 31, 2001 the ESOP held 34,005,910 shares (2000, 45,514,664 shares).

BP has established a Qualifying Employee Share Ownership Trust (QUEST) to support the UK ShareSave plans. During the year, contributions of $36 million ($76 million) were made by the Company to the QUEST which, together with option-holder contributions, were used by the QUEST to subscribe for new ordinary shares at market price. The Company has transferred the cost of this contribution directly to retained profits and the excess of the subscription price over nominal value has increased the share premium account.

At December 31, 2001, all the 8,148,640 ordinary shares issued to the QUEST had been transferred to employees exercising options under the UK ShareSave plan.

	2001	2000
Employee share options granted during the year	(options thousands)	
Savings related schemes	7,901	7,930
BP Share Option Plan	58,208	50,461
	66,109	58,391

The exercise prices for BP options granted during the year were (pound) 5.11/$7.36 (7,900,810 options) for savings-related and similar schemes and (pound) 5.72/$8.23 (weighted average price) for 58,207,741 options granted under the BP Share Option Plan.

Pursuant to the various BP Group share option schemes, the following options for BP ordinary shares of the Company were outstanding at March 26, 2002:

Options	Expiry dates of	Exercise price

outstanding	options	per share
(shares)		
454,497,933	2002 to 2012	$3.47 to $9.97

Further details on share options appear in Item 18 -- Financial Statements -- Note 33.

ITEM 7 -- MAJOR SHAREHOLDERS AND RELATED PARTY TRANSACTIONS

Major Shareholders

At March 26, 2002, the Company has been notified that JPMorgan Chase Bank (formerly known as Morgan Guaranty Trust Company), as the approved depositary for BP American Depositary Shares (ADSs), holds interests through its nominee, Guaranty Nominees Limited, in 6,846,608,538 ordinary shares (30.50% of the Company's ordinary share capital). Included in this total is part of the holding of the Kuwait Investment Office (KIO). Either directly or through nominees, the KIO holds interests in 715,040,000 ordinary shares (3.19% of the Company's ordinary share capital).

Related Party Transactions

The Group had no material transactions with joint ventures and associated undertakings during the three years ended December 31, 2001. Transactions between the Group and its significant joint ventures and associated undertakings are summarised in Item 18 -- Financial Statements -- Note 41.

In the ordinary course of its business the Group has transactions with various organizations with which certain of its directors are associated but, except as described in this report, no material transactions responsive to this item have been entered into in the period commencing January 1, 2001 to March 26, 2002.

ITEM 8 -- FINANCIAL INFORMATION

CONSOLIDATED STATEMENTS AND OTHER FINANCIAL INFORMATION

Financial Statements

See Item 18 -- Financial Statements.

Dividends

Our financial framework, after adopting FRS 19, is to maintain a ratio of net debt to net debt plus equity, after adjusting equity for the fixed asset revaluation adjustment and goodwill consequent upon the ARCO and Burmah Castrol acquisitions, of around 25-35% and a dividend policy which aims to return to shareholders around 60% of our replacement cost profit before exceptional items and after adjusting for special items and acquisition amortization, adjusted to mid-cycle operating conditions. Special items are non-recurring charges and credits that are not classified as exceptional items under UK GAAP. Acquisition amortization refers to depreciation relating to the fixed asset revaluation adjustment and amortization of goodwill consequent upon the ARCO and Burmah Castrol acquisitions. Mid-cycle operating conditions reflect not only adjustments to hydrocarbon prices and margins, but also costs and capacity utilization to levels which we would expect on average over the long term. If circumstances give us a larger surplus of cash than is required to fund our capital programme and meet operational needs, the surplus may be used to pay down debt to a level at the lower end of our gearing range and/or be returned to shareholders.

Legal Proceedings

Save as disclosed in the following paragraphs, no member of the Group is a party to, and no property of a member of the Group is subject to, any pending legal proceedings which are significant to the Group.

Approximately 200 lawsuits were filed in State and Federal Courts in Alaska seeking compensatory and punitive damages arising out of the Exxon Valdez oil spill in Prince William Sound in March 1989. Most of those suits named Exxon (now ExxonMobil), Alyeska Pipeline Service Company (Alyeska), which operates the oil terminal at Valdez, and the other oil companies which own Alyeska. Alyeska initially responded to the spill until the response was taken over by Exxon. BP owns a 47% interest (reduced during 2001 from 50% by a sale of 3% to Phillips) in Alyeska through a subsidiary of BP America Inc. and briefly indirectly owned a further 20% interest in Alyeska following BP's combination with ARCO. Alyeska and its owners have settled all the claims against them under these lawsuits. Exxon has indicated that it may file a claim for contribution against Alyeska for a portion of the costs and damages which it has incurred. If any claims are asserted by Exxon which affect Alyeska and its owners, BP will defend the claims vigorously.

Since 1987, ARCO, a current subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the United States alleging injury to persons and property caused by lead pigment in paint. The majority of the lawsuits have been abandoned or dismissed as against ARCO. ARCO is named in these lawsuits as alleged successor to International Smelting and Refining which, along with a predecessor company, manufactured lead pigment during the period 1920-1946. Plaintiffs include individuals and governmental entities. Several of the lawsuits purport to be class actions. The lawsuits (depending on plaintiff) seek various remedies including: compensation to lead-poisoned children; cost to find and remove lead paint from buildings; medical monitoring and screening programmes; public warning and education of lead hazards; reimbursement of government healthcare costs and special education for lead-poisoned citizens; and punitive damages. No case has been settled or tried. While the amounts claimed could be substantial and it is not possible to predict the outcome of these legal actions, ARCO believes that it has valid defences and it intends to defend such actions vigorously. Consequently, BP believes that the impact of these lawsuits on the Group's results of operations, financial position or liquidity will not be material.

The Group is subject to numerous and local environment laws and regulations concerning its products, operations and other activities. These laws and regulations may require the Group to take future action to remediate the effects on the environment of prior disposal or release of chemicals or petroleum substances by the Group or other parties. Such contingencies may exist for various sites including refineries, chemical plants, oil fields, service stations, terminals and waste disposal sites. In addition, the Group may have obligations relating to prior asset sales of closed facilities. The ultimate requirement for remediation and its cost are inherently difficult to estimate. However, the estimated cost of known environmental obligations has been provided in our accounts in accordance with the Group's accounting policies. See Item 18 -- Financial Statements -- Note 27. While the amounts of future costs could be significant and could be material to the Group's results of operations in the period in which they are recognized, BP does not expect these costs to have a material effect on the Group's financial position or liquidity.

For certain information regarding environmental proceedings see Item 4 -- Environmental Protection -- Legislation and Regulation -- United States.

SIGNIFICANT CHANGES

None.

ITEM 9 -- THE OFFER AND LISTING

Markets and Market Prices

The primary market for BP's ordinary shares is the London Stock Exchange. BP's ordinary shares are a constituent element of the Financial Times Stock Exchange 100 Index. BP's ordinary shares are also traded on stock exchanges in France, Germany, Japan and Switzerland.

Trading of BP's shares on the LSE is primarily through the use of the Stock Exchange Electronic Trading Service (SETS), introduced in 1997 for the largest companies in terms of market capitalization whose primary listing is the LSE. Under SETS, buy and sell orders at specific prices may be sent to the exchange electronically by any firm which is a member of the LSE, on behalf of a client or on behalf of itself acting as a principal. The orders are then anonymously displayed in the order book. When there is a match on a 'buy' and a 'sell' order, the trade is executed and automatically reported to the LSE. Trading is continuous from 8:00 a.m. to 4:30 p.m. UK time, but in the event of a 20% movement in the share price either way the LSE may impose a temporary halt in the trading of that company's shares in the order book, to allow the market to re-establish equilibrium. Dealings in BP's ordinary shares may also take place between an investor and a market-maker, via a member firm, outside the electronic order book.

In the United States and Canada the Company's securities are traded in the form of American Depositary Shares (ADSs), for which Morgan Guaranty Trust Company of New York is the depositary (the Depositary) and transfer agent. The Depositary's address is 60 Wall Street, New York, NY 10260, USA. Each ADS represents six BP ordinary shares. ADSs are listed on the New York Stock Exchange, and are also traded on the Chicago, Pacific and Toronto Stock Exchanges. ADSs are evidenced by American Depositary Receipts, or ADRs, which may be issued in either certified or book entry form.

100

The following table sets forth for the periods indicated the highest and lowest middle market quotations for the BP ordinary shares of The British Petroleum Company p.l.c. for 1997 and 1998, and of BP p.l.c. for 1999, 2000 and 2001. These are derived from the Daily Official List of the LSE, and the highest and lowest sales prices of ADSs as reported on the New York Stock Exchange composite tape. The information in this table has been changed to reflect the subdivision of BP ordinary shares on October 4, 1999, whereby each ordinary share of $0.50 was subdivided into two ordinary shares of $0.25.

American

	Ordinary shares High	Ordinary shares Low	Depositary Shares (a) High	Depositary Shares (a) Low
	(Pence)		(Dollars)	
Year ended December 31,				
1997	478.25	331.75	46.50	32.44
1998	484.25	368.50	48.66	36.50
1999	643.50	411.00	62.63	40.19
2000	671.00	444.50	60.63	43.13
2001	647.00	491.50	55.20	42.20
Year ended December 31,				
2000: First quarter	622.50	444.50	60.63	43.13
Second quarter	649.00	506.00	59.31	46.98
Third quarter	671.00	564.50	58.38	50.50
Fourth quarter	646.50	517.50	57.31	45.13
2001: First quarter	609.00	526.50	53.50	46.12
Second quarter	647.00	562.00	55.20	47.50
Third quarter	610.50	504.00	53.05	43.01
Fourth quarter	594.50	491.50	51.95	42.20
2002: First quarter (through March 26)	617.00	589.50	52.90	49.36
Month of				
September 2001	591.50	504.00	51.41	43.01
October 2001	594.50	528.50	51.95	46.45
November 2001	566.00	491.50	49.65	42.20
December 2001	537.00	504.00	47.07	43.40
January 2002	550.00	511.00	46.80	43.75
February 2002	592.00	538.00	50.51	45.58
March 2002 (through March 26)	617.00	589.50	52.90	49.36

(a) An ADS is equivalent to six BP ordinary shares.

Market prices for the BP ordinary shares on the LSE and in after-hours trading off the LSE, in each case while the New York Stock Exchange is open, and the market prices for ADSs on the New York Stock Exchange and other North American stock exchanges, are closely related due to arbitrage among the various markets, although differences may exist from time to time due to various factors including UK stamp duty reserve tax. Trading in ADSs began on the LSE on August 3, 1987.

On March 26, 2002, 1,141,101,423 ADSs (equivalent to 6,846,608,538 BP ordinary shares or some 30.5% of the total) were outstanding and were held by approximately 181,000 ADR holders. Of these, about 179,000 had registered addresses in the USA at that date.

On March 26, 2002 there were approximately 357,000 holders of record of BP ordinary shares. Of these holders, around 1,400 had registered addresses in the United States and held a total of some 4,354,000 BP ordinary shares. In addition, certain accounts of record with registered addresses other than in the United States hold BP ordinary shares, in whole or in part, beneficially for United States persons.

ITEM 10 -- ADDITIONAL INFORMATION

MEMORANDUM AND ARTICLES OF ASSOCIATION

The following summarizes certain provisions of BP's memorandum and articles of association and applicable English law. This summary is qualified in its entirety by reference to the UK Companies Act and BP's memorandum and articles of association. Information on where investors can obtain copies of the memorandum and articles of association is described under the heading 'Documents on Display' under this Item.

Objects and Purposes

BP is incorporated under the name BP p.l.c. and is registered in England and Wales with registered number 102498. Clause 4 of BP's memorandum of association provides that its objects include the acquisition of petroleum bearing lands; the carrying on of refining and dealing businesses in the petroleum, manufacturing, metallurgical or chemicals businesses; the purchase and operation of ships and all other vehicles and other conveyances; and the carrying on of any other businesses calculated to benefit BP. The memorandum grants BP a range of corporate capabilities to effect these objects.

Directors

The business and affairs of BP shall be managed by the directors.

The articles of association place a general prohibition on a director voting in respect of any contract or arrangement in which he has a material interest other than by virtue of his interest in shares in the Company. However, in the absence of some other material interest not indicated below, a director is entitled to vote and to be counted in a quorum for the purpose of any vote relating to a resolution concerning the following matters:

- The giving of security or indemnity with respect to any money lent or obligation taken by the director at the request or benefit of the Company;

- Any proposal in which he is interested concerning the underwriting of Company securities or debentures;

- Any proposal concerning any other company in which he is interested, directly or indirectly (whether as an officer or shareholder or otherwise) provided that he and persons connected with him are not the holder or holders of one percent or more of the voting interest in the shares of such company;

- Proposals concerning the modification of certain retirement benefits schemes under which he may benefit and which has been approved by either the UK Board of Inland Revenue or by the shareholders; and

- Any proposal concerning the purchase or maintenance of any insurance policy under which he may benefit.

The UK Companies Act requires a director of a company who is in any way interested in a contract or proposed contract with the company to declare the nature of his interest at a meeting of the directors of the company. The directors may exercise all the powers of the company to borrow money, except that the amount remaining undischarged of all moneys borrowed by the company shall not, without approval of the shareholders, exceed the amount paid up on the share capital plus the aggregate of the amount of the capital and revenue reserves of the company. Variation of the borrowing power of the board may only be effected by amending the articles of association.

Remuneration of non-executive directors shall be determined in the aggregate by resolution of the shareholders. Remuneration of executive directors is determined by the Remuneration Committee. This committee is made up of non-executive directors only. Any director attaining the age of 70 shall retire at the next annual general meeting. There is no requirement of share ownership for a director's qualification.

Dividend Rights; Other Rights to Share in Company Profits; Capital Calls

If recommended by the directors of BP, BP shareholders may, by resolution, declare dividends but no such dividend may be declared in excess of the amount recommended by the directors. The directors may also pay interim dividends without obtaining shareholder approval. No dividend may be paid other than out of profits available for distribution, as determined under UK GAAP and the UK Companies Act. Dividends on BP ordinary shares are payable only after payment of dividends on BP preference shares. Any dividend unclaimed after a period of twelve years from the date of declaration of such dividend shall be forfeited and reverts to BP.

102

Apart from shareholders' rights to share in BP's profits by dividend (if any is declared), the articles of association provide that the directors may set aside:

-- a special reserve fund out of the balance of profits each year to make up any deficit of cumulative dividend on the BP preference shares; and

-- a general reserve out of the balance of profits each year, which shall be applicable for any purpose to which the profits of the Company may properly be applied. This may include capitalization of such sum, pursuant to an ordinary shareholders' resolution, and distribution to shareholders as if it were distributed by way of a dividend on the ordinary shares or in paying up in full unissued ordinary shares for allotment and distribution as bonus shares.

Any such sums so deposited may be distributed in accordance with the manner of distribution of dividends as described above.

Holders of shares are not subject to calls on capital by the Company, provided that the amounts required to be paid on issue have been paid off. All shares are fully paid.

Voting Rights

The articles of association of BP provide that voting on resolutions at a shareholders' meeting will be decided on a poll other than resolutions of a procedural nature, which may be decided on a show of hands. If voting is on a poll, every shareholder who is present in person or by proxy has one vote for every ordinary share held and two votes for every (pound)5 in nominal amount of BP preference shares held. If voting is on a show of hands, each shareholder who is present at the meeting in person or whose duly appointed proxy is present in person will have one vote, regardless of the number of shares held, unless a poll is requested. Shareholders do not have cumulative voting rights.

Holders of record of ordinary shares may appoint a proxy, including a beneficial owner of those shares, to attend, speak and vote on their behalf at any shareholders' meeting.

Record holders of BP ADSs also are entitled to attend, speak and vote at any shareholders' meeting of BP by the appointment by the approved depositary, JP Morgan Chase Bank (formerly known as Morgan Guaranty Trust Company), of them as proxies in respect of the ordinary shares represented by their ADSs. Each such proxy may also appoint a proxy. Alternatively, holders of ADSs are entitled to vote by supplying their voting instructions to the depositary, who will vote the ordinary shares represented by their ADSs in accordance with their instructions.

Proxies may be delivered electronically.

Matters are transacted at shareholders' meetings by the proposing and passing of resolutions, of which there are three types: ordinary, special or extraordinary.

An ordinary resolution requires the affirmative vote of a majority of the votes of those persons voting at a meeting at which there is a quorum. Special and extraordinary resolutions require the affirmative vote of not less than three-fourths of the persons voting at a meeting at which there is a quorum. Any annual general meeting at which it is proposed to put a special or ordinary resolution requires 21 days' notice. An extraordinary resolution put to the annual general meeting requires no notice period. Any extraordinary general meeting at which it is proposed to put a special resolution requires 21 days' notice; otherwise, the notice period for an extraordinary general meeting is 14 days.

Liquidation Rights; Redemption Provisions

In the event of a liquidation of BP, after payment of all liabilities and applicable deductions under UK laws and subject to the payment of secured creditors, the holders of BP preference shares would be entitled to the sum of (i) the capital paid up on such shares plus, (ii) accrued and unpaid dividends and (iii) a premium equal to the higher of (a) 10% of the capital paid up on the BP preference shares and (b) the excess of the average market price over par value of such shares on the London Stock Exchange during the previous six months. The remaining assets (if any) would be divided pro rata among the holders of BP ordinary shares.

Without prejudice to any special rights previously conferred on the holders of any class of shares, BP may issue any share with such preferred, deferred or other special rights, or subject to such restrictions as the shareholders by resolution determine (or, in the absence of any such resolution, by determination of the directors), and may issue shares which are to or may be redeemed.

Variation of Rights

The rights attached to any class of shares may be varied with the consent in writing of holders of 75% of the shares of that class or upon the adoption of an extraordinary resolution passed at a separate meeting of the holders of the shares of that class. At every such separate meeting, all of the provisions of the articles of association relating to proceedings at a general meeting apply, except that the quorum with respect to meeting to change the rights attached to the preference shares is 10% or more of the shares of that class, and the quorum to change the rights attached to the ordinary shares is one third or more of the shares of that class.

Shareholders' Meetings and Notices

Shareholders must provide BP with a postal or electronic address in the UK in order to be entitled to receive notice of shareholders' meetings. In certain circumstances, BP may give notices to shareholders by advertisement in UK newspapers. Holders of BP ADSs are entitled to receive notices under the terms of the deposit agreement relating to BP ADSs. The substance and timing of notices is described above under the heading Voting Rights.

Under the articles of association, the annual general meeting of shareholders will be held within 15 months after the preceding annual general meeting and at a time and place determined by the directors within the United Kingdom. If any shareholders' meeting is adjourned for lack of quorum, notice of the time and place of the meeting may be given in any lawful manner, including electronically.

Limitations on Voting and Shareholding

There are no limitations imposed by English law or BP's memorandum or articles of association on the right of non-residents or foreign persons to hold or vote the Company's ordinary shares or ADSs, other than limitations that would generally apply to all of the shareholders.

Disclosure of Interests in Shares

The UK Companies Act permits a public company, on written notice, to require any person whom the company believes to be or, at any time during the previous three years prior to the issue of the notice, to have been interested in its voting shares, to disclose certain information with respect to those interests. Failure to supply the information required may lead to disenfranchisement of the relevant shares and a prohibition on their transfer and receipt of dividends and other payments in respect of those shares. In this context the term `interest' is widely defined and will generally include an interest of any kind whatsoever in voting shares, including any interest of a holder of BP ADSs.

MATERIAL CONTRACTS

The following contract (not being contracts entered into in the ordinary course of business) has been entered into by members of the Group since January 1, 1999 that is material:

A merger agreement under Delaware law dated March 31, 1999 and amended as of July 12, 1999 and again as of March 27, 2000 pursuant to which Prairie Holdings (a wholly-owned subsidiary of BP) was to be merged with and into ARCO and ARCO was to become a wholly-owned subsidiary of BP. Under the terms of the merger, each ARCO shareholder was entitled to receive 9.84 BP ordinary shares (in the form of BP ADSs) for each ARCO share. The merger agreement contained certain customary representations and warranties by ARCO and BP with respect to themselves and their respective subsidiaries, regarding, among other things, due organization, good standing and qualification, capital structure, corporate authority and compliance with corporate governance documents, government filings, reports and financial statements, litigation and liabilities, absence of certain changes, employee benefits, environmental matters and tax matters. The merger was declared effective on April 18, 2000, at which time 3,186,006,476 BP ordinary shares were issued as consideration in the merger.

EXCHANGE CONTROLS AND OTHER LIMITATIONS AFFECTING SECURITY HOLDERS

There are currently no UK foreign exchange controls or restrictions on remittances of dividends on the BP ordinary shares or on the conduct of the Company's operations.

There are no limitations, either under the laws of the UK or under the articles of association of BP p.l.c., restricting the right of non-resident or foreign owners to hold or vote BP ordinary or preference shares in the Company.

TAXATION

The following summary of the principal UK and certain US tax consequences of ownership of ADSs or BP ordinary shares is based in part on representations of Morgan Guaranty Trust Company of New York as Depositary for the ADRs evidencing the ADSs and assumes that each obligation in the deposit agreement among the Company, the Depositary and the holders from time to time of ADRs and any related agreement will be performed in accordance with its terms.

Beneficial owners of ADSs who are resident in the USA are treated as the owners of the underlying BP ordinary shares for the purposes of the income tax convention between the USA and the UK (the Convention) and for the purposes of the US Internal Revenue Code of 1986, as amended (the Code). Unless otherwise stated, references to 'shareholders' or 'shareholder' below are to persons who are the beneficial owners of the underlying BP ordinary shares. It should be noted that a new income tax convention between the USA and the UK was signed on July 24, 2001 and is awaiting ratification by both countries.

For purposes of this discussion, a US Holder is a beneficial owner of the Company's shares who for the purposes of the Convention is not a US corporation owning directly or indirectly 10% or more of the Company's voting stock, and who is a resident of the USA and is not a resident of the UK.

Certain UK and US tax consequences of owning ADSs

The tax credit for an individual shareholder resident in the UK is reduced to 1/9 of the amount of the net dividend (or 10% of the net dividend plus the tax credit). This tax credit continues to be available to set against the individual's tax liability on the dividend, but is no longer refundable to the individual.

For purposes of this section, with respect to any dividend paid by the Company, Refund means an amount equal to the tax credit available to individual shareholders resident in the UK in respect of such dividend, less a withholding tax equal to 15% (limited to the amount of the tax credit) of the aggregate of such tax credit and such dividend.

A US holder, as defined above, that is eligible for the benefits under the convention (an eligible US Holder) is entitled, in principle, to receive the Refund. However, no actual refund is available to eligible US Holders under the convention since the amount of witholding tax (at 15%) exceeds the 10% tax credit available to individual shareholders resident in the UK. Thus, for example, a dividend of $8.00, will result in a net receipt after UK tax but before US tax of $8.00 that is the withholding tax does not reduce the dividend below the net dividend of $8.00.

Dividends (including amounts in respect of the tax credit and any amounts withheld) must be included in gross income by a shareholder subject to US taxation and will generally be treated as foreign source 'passive income' or, in the case of certain US Holders, 'financial services income' for foreign tax credit limitations purposes. Such dividends will generally not be eligible for the dividends received deduction allowed to US corporations. The IRS has recently confirmed, that, in the case of Eligible US Holders, subject to certain limitations, the UK withholding tax as determined by the Convention (that is an amount equal to 1/9 of the cash dividend) will be treated as a foreign income tax that is eligible for credit against the US Holders' federal income tax. To qualify for such credit, Eligible US Holders must make an election on Form 8833 (a Treaty-Based Return Position Disclosure, under Section 6114 or 7701(b)), which must be filed with their tax return, in addition to any other filings that may be required. At the end of the calendar year during which the dividends are paid, US Holders will receive a Form 1099 confirming the amount of dividends received.

Share Dividend Choice for BP ADR Holders

ADR holders electing to receive ADSs instead of a cash dividend (see Item 3 -- Key Information -- Dividends) will not be entitled to any Refund from the UK Inland Revenue, nor will the 15% withholding tax apply, with respect to such dividends.

For US tax purposes the receipt of additional ADSs will be treated as a dividend distribution. An ADR holder who is subject to US taxation will generally be treated as having received gross income equal to the fair market value of the ADSs (or fraction thereof) on the date of the share distribution in London (with no reduction for the stamp duty reserve tax referred to below). The US resident ADR holder will receive a tax basis in the ADSs equal to such fair market value. Corporations will not be entitled to a dividends received deduction on receipt of a share dividend.

105

UK Taxation of Capital Gains

A US Holder will be liable to UK tax on capital gains realized on the sale or other disposition of BP ordinary shares only if the US Holder is resident (or, in the case of an individual, ordinarily resident) for UK tax purposes in the UK or if he carries on a trade, profession or vocation in the UK through a permanent establishment and the BP ordinary shares are (i) used for the purposes of the trade, profession or vocation, or (ii) used, held or acquired for the purposes of the permanent establishment.

The liability to UK capital gains tax for a US Holder of ADRs is the same as that for a US Holder of BP ordinary shares, except that a US Holder of ADRs who is resident but not domiciled in the UK will not be taxed on gains realized on the sale or other disposition of ADSs if the proceeds are not remitted to the UK.

UK Inheritance Tax

UK capital transfer tax was restructured and renamed 'inheritance tax' in 1986. The US-UK double taxation convention relating to estate and gift taxes (the Estate Tax Convention) applies to inheritance tax. ADRs held by an individual who is domiciled for the purposes of the Estate Tax Convention in the USA and is not for the purposes of the Estate Tax Convention a national of the UK will not be subject to inheritance tax on death or on transfer during the individual's lifetime unless, among other things, the ADSs are part of the business property of a permanent establishment situated in the UK or pertain to a fixed base situated in the UK used for the performance of independent personal services. In the exceptional case where ADSs are subject both to inheritance tax and to US Federal gift or estate tax, the Estate Tax Convention generally provides for tax paid in the UK to be credited against tax payable in the USA or for tax paid in the USA to be credited against tax payable in the UK based on priority rules set forth in the Estate Tax Convention.

UK Stamp Duty and Stamp Duty Reserve Tax

The statements below relate to what is understood to be the current practice of the UK Inland Revenue under existing law.

Provided that the instrument of transfer is not executed in the UK and remains at all times outside the UK, and the transfer does not relate to any matter or thing done or to be done in the UK, no UK stamp duty is payable on the acquisition or transfer of ADSs. Neither will an agreement to transfer ADSs in the form of ADRs give rise to a liability to stamp duty reserve tax.

Purchases of BP ordinary shares, as opposed to ADSs, through the CREST system of paperless share transfers will be subject to stamp duty reserve tax at a rate of 0.5%. The charge will arise as soon as there is an agreement for the transfer of the shares (or, in the case of a conditional agreement, when the condition is fulfilled). The stamp duty reserve tax will apply to agreements to transfer BP ordinary shares even if the agreement is made outside the UK between two non-residents. Purchases of BP ordinary shares outside the CREST system are subject either to stamp duty at a rate of 50 pence per (pound) 100 (or part), or stamp duty reserve tax at 0.5%. Stamp duty and stamp duty reserve tax are generally the liability of the purchaser. A subsequent transfer of BP ordinary shares to the Depositary's nominee will give rise to further stamp duty at the rate of (pound) 1.50 per (pound) 100 (or part) or stamp duty reserve tax at the rate of 1.5% of the value of the BP ordinary shares at the time of the transfer.

A transfer of the underlying BP ordinary shares to an ADR holder upon cancellation of the ADSs without transfer of beneficial ownership will give rise to UK stamp duty at the rate of (pound) 5 per transfer.

An ADR holder electing to receive ADSs instead of a cash dividend will be responsible for the stamp duty reserve tax due on issue of shares to the Depositary's nominee and calculated at the rate of 1.5% on the issue price of the shares. Current UK Inland Revenue practice is to calculate the issue price by reference to the total cash receipt (i.e. cash dividend plus the Refund if any) to which a US Holder would have been entitled had the election to receive ADSs instead of a cash dividend not been made. ADR holders electing to receive ADSs instead of the cash dividend authorize the Depositary to sell sufficient shares to cover this liability.

DOCUMENTS ON DISPLAY

It is possible to read and copy documents referred to in this annual report on Form 20-F that have been filed with the SEC at the SEC's public reference room located at 450 Fifth Street, NW, Washington, DC 20549 and at the SEC's other public reference rooms in New York City and Chicago. Please call the SEC at 1-800-SEC-0330 for further information on the public reference rooms and their copy charges. The SEC filings are also available to the public from commercial document retrieval services and, for most recent BP periodic filings only, at the Internet world wide web site maintained by the SEC at www.sec.gov.

ITEM 11 -- QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

BP is exposed to a number of different market risks arising from the Group's normal business activities. Market risk is the possibility that changes in currency exchange rates, interest rates or oil and natural gas prices will adversely affect the value of the Group's financial assets, liabilities or expected future cash flows. The Group has developed policies aimed at managing the volatility inherent in certain of these natural business exposures and in accordance with these policies the Group enters into various transactions using derivative financial and commodity instruments (derivatives). Derivatives are contracts whose value is derived from one or more underlying financial instruments, indices or prices which are defined in the contract. We also trade derivatives in conjunction with these risk management activities.

In market risk management and trading, conventional exchange-traded derivative instruments such as futures and options are used, as well as non-exchange-traded instruments such as swaps, 'over-the-counter' options and forward contracts.

Where derivatives constitute a hedge, the Group's exposure to market risk created by the derivative is offset by the opposite exposure arising from the asset, liability or transaction being hedged. By contrast, where derivatives are held for trading purposes, changes in market risk factors give rise to realized and unrealized gains and losses, which are recognized in the current period.

All financial instrument and derivative activity, whether for risk management or trading, is carried out by specialist teams which have the appropriate skills, experience and supervision. These teams are subject to close financial and management control, meeting generally accepted industry practice and reflecting the principles of the Group of Thirty Global Derivatives Study recommendations. A Trading Risk Management Committee has oversight of the quality of internal control in the Group's trading units. Independent control functions monitor compliance with BP's policies. The control framework includes prescribed trading limits that are reviewed regularly by senior management, daily monitoring of risk exposure using value-at-risk principles, marking trading exposures to market and stress testing to assess the exposure to potentially extreme market situations. As part of its approach to ensuring that control over trading is maintained to a high and consistent standard, the Group's business units dealing in the oil, natural gas and financial markets were brought together within a single integrated supply and trading organization during 2001.

Further information about BP's use of derivatives, their characteristics, and the accounting treatment thereof is given in Item 18 -- Note 1 and Note 28.

The Group's accounting policies under UK GAAP do not satisfy the criteria for hedge accounting under Statement of Financial Accounting Standards No. 133 'Accounting for Derivative Instruments and Hedging Activities'. The Group does not intend to modify its practice under UK GAAP. See Item 18 -- Financial Statements -- Note 43 for further information.

Risk Management

Foreign Currency Exchange Rate Risk

Fluctuations in exchange rates can have significant effects on the Group's reported results. The effects of most exchange rate fluctuations are absorbed in business operating results through changing cost competitiveness, lags in market adjustment to movements in rates, and conversion differences accounted for on specific transactions. For this reason, the total effect of exchange rate fluctuations is not identifiable separately in the Group's reported results.

The main underlying economic currency of the Group's cash flows is the US dollar. This is because BP's major product, oil, is priced internationally in US dollars. BP's foreign exchange management policy is to minimize economic and material transactional exposures arising from currency movements against the US dollar. The Group co-ordinates the handling of foreign exchange risks centrally, by netting off naturally occurring opposite exposures wherever possible, to reduce the risks, and then dealing with any material residual foreign exchange risks. Significant residual non-US dollar exposures are managed using a range of derivatives. The most significant of such exposures are the sterling-based capital leases, that part of the quarterly dividend which is paid in sterling, the sterling cash flow requirements for UK Corporation Tax, and the capital expenditure and operational requirements of Exploration and Production, mainly in the UK. In addition, most of the Group's borrowings are in US dollars, are hedged with respect to the US dollar, or are swapped into US dollars. At December 31, 2001, the total of foreign currency borrowings not swapped into US dollars amounted to $449 million. The principal elements of this are $133 million of borrowings in sterling, $85 million in Malaysian ringgit, $77 million in Trinidad and Tobago dollars and $70 million in South African rand.

107

The following table provides information about the Group's foreign currency derivative financial instruments. These include foreign currency forward exchange agreements (forwards) that are sensitive to changes in the sterling/US dollar, euro/US dollar and Norwegian krone/US dollar exchange rates. Where foreign currency denominated borrowings are swapped into US dollars using forwards or currency interest rate swaps such that currency risk is completely eliminated, neither the borrowing nor the derivative are included in the table.

The table presents the notional amounts and weighted average contractual exchange rates by contractual maturity dates and exclude forwards that have offsetting positions. Only significant forward positions are included in the tables. The notional amounts of forwards are translated into US dollars at the exchange rate included in the contract at inception. The majority of the sterling contracts consist of forwards relating to sterling-based capital leases which effectively convert the lease obligation from sterling into US dollars. The remaining contracts relate to sterling requirements for UK tax payments and UK dividend payments and net operational expenditures. The euro forward contracts relate mainly to payments for capital expenditure. The Norwegian krone forward contracts relate to the Group's Norwegian tax payments over the next year. The fair value represents an estimate of the gain or loss which would be realized if the contracts were settled at the balance sheet date.

The fair values for the foreign exchange contracts in the table below are based on market prices of comparable instruments (forwards). These derivative contracts constitute a hedge; any change in the fair value or expected cash flows is offset by an opposite change in the market value or expected cash flows of the asset, liability or transaction being hedged.

	Notional amount by expected maturity date						
	2002	2003	2004	2005	2006	Total	Fair v a (liabi

($ million)

At December 31, 2001						
Forwards						
Receive sterling/pay US dollars						
Contract amount....................	3,822	(48)	--	--	--	3,774
Weighted average contractual exchange rate....................	1.44					
Receive euro/pay US dollars						
Contract amount....................	1,055	190	55	13	1	1,314
Weighted average contractual exchange rate....................	0.90					
Receive Norwegian krone/pay US dollars						
Contract amount....................	172	6	2	1	--	181
Weighted average contractual exchange rate (a)................	9.49					

	2001	2002	2003	2004	Total	Fair value asset/ (liability)
			($ million)			
At December 31, 2000						
Forwards						
Receive sterling/pay US dollars						
Contract amount....................	3,299	--	--	--	3,299	(30)
Weighted average contractual exchange rate....................	1.52					
Receive euro/pay US dollars						
Contract amount....................	663	45	23	13	744	(16)
Weighted average contractual exchange rate....................	1.01					
Receive Norwegian krone/pay US dollars						
Contract amount....................	199	--	--	--	199	6
Weighted average contractual exchange rate (a)................	9.19					

(a) Weighted average contractual exchange rates are expressed as US dollars per non-US dollar currency unit except Norwegian krone which are expressed as krone per US dollar.

Interest Rate Risk

BP is exposed to interest rate risk on short- and long-term floating rate instruments and as a result of the refinancing of fixed rate finance debt. Consequently, as well as managing the currency and the maturity of debt, the Group manages interest expense through the balance between generally lower-cost floating rate debt, which has inherently higher risk, and generally more expensive but lower-risk, fixed rate debt. The Group is exposed predominantly to US dollar LIBOR interest rates as borrowings are mainly denominated in, or swapped into, US dollars. The Group uses derivatives to achieve the required mix between fixed and floating rate debt. During 2001, the proportion of floating rate debt was in the range of 32-43% of total net debt outstanding.

The following table shows, by major currency, the Group's borrowings at December 31, 2001 and 2000 and the weighted average interest rates achieved at those dates through a combination of borrowings and other interest rate sensitive instruments entered into to manage interest rate exposure.

	Fixed rate debt			Floating rate debt	
	Weighted average interest rate	Weighted average time for which rate is fixed	Amount	Weighted average interest rate	Amount
	(%)	(Years)	($ million)	(%)	($ million)
At December 31, 2001					
US dollar.....................	7	8	11,485	2	7,842
Sterling......................	--	--	--	4	133
Other currencies..............	10	29	122	6	194
			11,607		8,169
At December 31, 2000					
US dollar.....................	7	9	10,199	6	8,326
Sterling......................	--	--	--	6	449
Other currencies..............	8	30	45	10	247
			10,244		9,022

The Group's earnings are sensitive to changes in interest rates over the forthcoming year as a result of the floating rate instruments included in the Group's finance debt at December 31, 2001. These include the effect of interest rate and currency swaps and forwards utilized to manage interest rate risk. If the interest rates applicable to floating rate instruments were to have increased by 1% on January 1, 2002, the Group's 2002 earnings before taxes would decrease by approximately $100 million. This assumes that the amount and mix of fixed and floating rate debt, including capital leases, remains unchanged from that in place at December 31, 2001 and that the change in interest rates is effective from the beginning of the year. Where the interest rate applicable to an instrument is reset during a quarter it is assumed that this occurs at the beginning of the quarter and remains unchanged for the rest of the year. In reality, the fixed/floating rate mix will fluctuate over the year and interest rates will change continually. Furthermore the effect on earnings shown by this analysis does not consider the effect of an overall reduction in economic activity which could accompany such an increase in interest rates.

Oil Price Risk

The Group's risk management policy with respect to oil price risk is to manage only those exposures associated with the immediate operational programme for certain of its equity share of production and certain of its refinery and marketing activities. To this end, BP's supply and trading organization uses the full range of conventional oil price-related financial and commodity derivatives available in the oil markets.

The derivative instruments used for hedging purposes do not expose the Group to market risk because the change in their market value is offset by an equal and opposite change in the market value of the asset, liability or transaction being hedged. The values at risk in respect of derivatives held for oil price risk management purposes are shown in isolation in the table below. The items being hedged are not included in the values at risk.

The value at risk model used is that discussed under Trading below, except that value at risk in respect of oil price risk management does not take into account physical crude oil or refined product positions held by the Group. Thus the value at risk calculation for oil price exposure includes derivative financial instruments such as exchange-traded futures and options, swap agreements and over-the-counter options and derivative commodity instruments (commodity contracts that permit settlement either by delivery of the underlying commodity or in cash) such as forward contracts. The values at risk represent the potential gain or loss in fair values over a 24-hour period with a 99.7% confidence level.

The following table shows values at risk for oil price risk management activities.

	High	Low	Average	December 31
		($ million)		
2001				
Oil price contracts...........................	11	4	7	7
2000				
Oil price contracts...........................	18	11	15	11
1999				
Oil price contracts...........................	5	3	3	5

Natural Gas Price Risk

BP's general policy with respect to natural gas price risk is to manage only a portion of its exposure to price fluctuations. Natural gas swaps, options and futures are used to convert specific sales and purchases contracts from fixed prices to market prices. Swaps are also used to hedge exposure to price differentials between locations. We also use derivatives to fix prices which are favorable with respect to our forecasts of future prices.

The table below provides information about the Group's material swaps contracts that are sensitive to changes in natural gas prices. Contract amount represents the notional amount of the contract. Fair value represents an estimate of the gain or loss which would be realized if the contracts were settled at the balance sheet date. Weighted average price represents the year-end forward price for futures, the fixed price and the year-end forward price related to the settlement month for swaps; and the weighted average strike price for options.

At December 31, 2001, in addition to the swaps contracts shown in the table there were options contracts with aggregate notional amounts of $1,090 million ($7 million at December 31, 2000) and terms of up to one year and futures contracts with aggregate gross contract amounts of $35 million ($96 million at December 31, 2000).

	Quantity	Gross Contract amount	Fair value Asset	Fair value Liability
	(Btu trillion)(a)	($ million)	($ million)	
At December 31, 2001				
Maturing in 2002				
Swaps				
Receive variable/pay fixed.....	447	1,600	17	(419)
Receive fixed/pay variable.....	302	1,002	210	(27)
Receive and pay variable.......	4,232	44	653	(610)
Maturing in 2003				
Swaps				
Receive variable/pay fixed.....	104	349	37	(47)
Receive fixed/pay variable.....	86	272	25	(32)
Receive and pay variable.......	682	4	52	(55)
Maturing in 2004				
Swaps				
Receive variable/pay fixed.....	20	63	11	(6)
Receive fixed/pay variable.....	8	20	4	(10)
Receive and pay variable.......	230	7	18	(25)
Maturing in 2005				
Swaps				
Receive variable/pay fixed.....	3	8	2	(1)
Receive fixed/pay variable.....	4	11	2	(4)
Receive and pay variable.......	165	8	12	(20)
Maturing in 2006				
Swaps				
Receive variable/pay fixed.....	2	7	--	(1)
Receive fixed/pay variable.....	3	10	2	(2)
Receive and pay variable.......	102	9	5	(14)
Maturing beyond 2006				
Swaps				
Receive variable/pay fixed.....	3	12	--	(1)
Received fixed/pay variable....	13	43	5	(10)
Receive and pay variable.......	318	25	22	(48)
At December 31, 2000				
Maturing in 2001				
Swaps				
Receive variable/pay fixed.....	30	129	72	(1)
Receive fixed/pay variable.....	12	67	1	(28)
Receive and pay variable.......	265	1,932	46	(72)
Maturing in 2002				
Swaps				
Receive variable/pay fixed.....	13	54	12	(1)
Receive fixed/pay variable.....	1	2	--	(1)
Receive and pay variable.......	40	198	2	(11)
Maturing in 2003				
Swaps				
Receive variable/pay fixed.....	2	7	--	--
Receive and pay variable.......	15	56	--	--

Maturing in 2004				
Swaps				
Receive variable/pay fixed.....	2	7	--	--
Receive and pay variable.......	2	7	--	--
Maturing in 2005				
Swaps				
Receive variable/pay fixed.....	2	7	--	--
Receive and pay variable.......	2	7	--	--
Maturing beyond 2005				
Swaps				
Receive variable/pay fixed.....	5	19	--	--
Receive and pay variable.......	5	19	--	--

(a) British thermal units (Btu)

(b) Million British thermal units (mmBtu)

Trading

In conjunction with the risk management activities discussed above, BP also trades interest rate and foreign currency exchange rate derivatives. The Group controls the scale of the trading exposures by using a value at risk model with a maximum value at risk limit authorized by the board.

In addition to the risk management activities related to equity crude disposal, refinery supply and marketing, BP's supply and trading organization undertakes trading in the full range of conventional derivative financial and commodity instruments and physical cargoes available in the oil markets. The Group also uses financial and commodity derivatives to manage certain of its exposures to price fluctuations on natural gas transactions. These activities are monitored and measured separately from the risk management activity and are subject to maximum value at risk limits authorized by the board. The Group increased the volume of its natural gas trading activity in 2001.

The Group measures its market risk exposure, that is potential gain or loss in fair values, on its trading activity using value-at-risk techniques. These techniques are based on a variance/covariance model or a Monte Carlo simulation and make a statistical assessment of the market risk arising from possible future changes in market values over a 24-hour period. The calculation of the range of potential changes in fair value takes into account a snapshot of the end-of-day exposures, and the history of one-day price movements over the previous twelve months, together with the correlation of these price movements. The potential movement in fair values is expressed to three standard deviations which is equivalent to a 99.7% confidence level. This means that, in broad terms, one would expect to see an increase or a decrease in fair values greater than the value at risk on only one occasion per year if the portfolio were left unchanged.

The Group calculates value at risk on all instruments that are held for trading purposes and that therefore give an exposure to market risk. The value-at-risk model takes account of derivative financial instruments such as interest rate forward and futures contracts, swap agreements, options and swaptions; foreign exchange forward and futures contracts, swap agreements and options; and oil and natural gas price futures, swap agreements and options.

Financial assets and liabilities and physical crude oil and refined products that are treated as trading positions are also included in these calculations. The value-at-risk calculation for oil and natural gas price exposure also includes derivative commodity instruments (commodity contracts that permit settlement either by delivery of the underlying commodity or in cash), such as forward contracts.

The following table shows values at risk for trading activities.

	High	Low	Average	December 31
		($ million)		
2001				
Interest rate trading.........................	1	--	--	--
Foreign exchange trading......................	3	--	1	--
Oil price trading.............................	29	10	18	17
Natural gas price trading.....................	21	4	10	9
2000				
Interest rate trading.........................	2	--	1	--
Foreign exchange trading......................	15	--	1	1
Oil price trading.............................	23	4	13	13
Natural gas price trading.....................	16	1	6	13
1999				
Interest rate trading.........................	1	--	1	--
Foreign exchange trading......................	13	--	3	1
Oil price trading.............................	15	5	9	10

112

The following table shows the changes during the year in the net fair value of non-exchange-traded instruments held for trading purposes.

	Fair value interest rate contracts	Fair value exchange rate contracts	Fair value oil price contracts	n
		($ million)		
Fair value of contracts at January 1, 2001......	--	--	36	
Contracts realized or settled in the year.......	--	--	(37)	
Fair value of new contracts when entered into during the year............................	--	--	--	
Changes in fair values attributable to changes in valuation techniques and assumptions.......	--	--	--	
Other changes in fair values...................	--	(3)	27	
Fair value of contracts at December 31, 2001	--	(3)	26	

The following table shows the net fair value of non-exchange-traded contracts held for trading purposes at December 31, 2001 analyzed by maturity period and by methodology of fair value estimation.

	Fair value of contracts at December 3			
	Maturity less than 1 year	Maturity 1-3 years	Maturity 4-5 years	Matu 5 y
			($ million)	
Prices actively quoted	9	1	--	
Prices provided by other external sources	3	3	--	
Prices based on models and other valuation methods	17	4	--	
	29	8	--	

ITEM 12 -- DESCRIPTION OF SECURITIES OTHER THAN EQUITY SECURITIES

Not applicable

113

PART II

ITEM 13 -- DEFAULTS, DIVIDEND ARREARAGES AND DELINQUENCIES

None.

ITEM 14 -- MATERIAL MODIFICATIONS TO THE RIGHTS OF SECURITY HOLDERS AND USE OF PROCEEDS

None.

114

PART III

ITEM 17 -- FINANCIAL STATEMENTS

Not applicable.

ITEM 18 -- FINANCIAL STATEMENTS

(a) Financial Statements

The following financial statements, together with the reports of the Independent Auditors thereon, are filed as part of this annual report:

ITEM 19 -- EXHIBITS

The following documents are filed as part of this annual report:

Exhibit 1	Memorandum and Articles of Association of BP p.l.c.
Exhibit 4.1	The BP Executive Directors' Long Term Incentive Plan*
Exhibit 4.2	Directors' Service Contracts*
Exhibit 7	Computation of Ratio of Earnings to Fixed Charges (Unaudited)
Exhibit 8	Subsidiaries

* Incorporated by reference to the Company's annual report on Form 20-F for the year ended December 31, 2000.

The total amount of long-term debt securities of the Registrant and its subsidiaries authorized under any one instrument does not exceed 10% of the total assets of BP p.l.c. and its subsidiaries on a consolidated basis. The Company agrees to furnish copies of any or all such instruments to the Securities and Exchange Commission upon request.

SIGNATURES

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

BP p.l.c.
(Registrant)

Dated: March 28, 2002

/S/ D. J. PEARL
....
D. J. PEARL
Deputy Company Secretary

REPORT OF INDEPENDENT AUDITORS

To: The Board of Directors
BP p.l.c.

We have audited the accompanying consolidated balance sheets of BP p.l.c. as of December 31, 2001 and 2000, and the related consolidated statements of income, changes in BP shareholders' interest, total recognized gains and losses, and cash flows for each of the three years in the period ended December 31, 2001. Our audits also included the financial statement schedule listed in the Index at Item 18. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United Kingdom and United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. 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 consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of BP p.l.c. at December 31, 2001 and 2000, and the consolidated results of its operations and its consolidated cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United Kingdom which differ in certain respects from those followed in the United States (see Note 43 of Notes to Financial Statements). Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/S/ ERNST & YOUNG LLP

Ernst & Young LLP

London, England
February 12, 2002

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference of our report dated February 12, 2002, with respect to the consolidated financial statements of BP p.l.c. included in this Annual Report (Form 20-F) for the year ended December 31, 2001 in the following Registration Statements:

Registration Statements on Form F-3 (File Nos. 333-9790 and 333-65996) of BP p.l.c.;

Registration Statements on Form F-3 (File Nos. 33-39075 and 33-20338) of BP America Inc. and BP p.l.c.;

Registration Statement on Form F-3 (File No. 33-29102) of The Standard Oil Company and BP p.l.c.;

Registration Statement on Form F-3 (File No. 333-83180) of BP Australia Capital Markets Limited, BP Canada Finance Company, BP Capital Markets p.l.c., BP Capital Markets America Inc. and BP p.l.c.; and

Registration Statements on Form S-8 (File Nos. 33-21868, 333-9020, 333-9798, 333-79399, 333-34968, 333-67206 and 333-74414) of BP p.l.c.

/S/ ERNST & YOUNG LLP

Ernst & Young LLP

London, England
March 28, 2002

F - 1

CONSOLIDATED STATEMENT OF INCOME

	Note	2001	2000	199
		Years ended December 31,		
		($ million, except per share am		
Turnover		175,389	161,826	101,18
Less: Joint ventures		1,171	13,764	17,61
Group turnover	2	174,218	148,062	83,56
Replacement cost of sales		146,893	120,720	68,61
Production taxes	3	1,689	2,061	1,01
Gross profit		25,636	25,281	13,93
Distribution and administration expenses	4	10,918	9,331	6,06
Exploration expense		480	599	54
		14,238	15,351	7,32
Other income	5	694	805	41
Group replacement cost operating profit		14,932	16,156	7,73
Share of profits of joint ventures		443	808	55
Share of profits of associated undertakings		760	792	60
Total replacement cost operating profit		16,135	17,756	8,89
Profit (loss) on sale of businesses or termination of operations	6	(68)	132	36
Profit (loss) on sale of fixed assets	6	603	88	(70
Restructuring costs	6	--	--	(1,94
Replacement cost profit before interest and tax		16,670	17,976	6,61
Inventory holding gains (losses)		(1,900)	728	1,72
Historical cost profit before interest and tax		14,770	18,704	8,34
Interest expense	7	1,670	1,770	1,31
Profit before taxation		13,100	16,934	7,02

Taxation	9	5,017	4,972	1,88
Profit after taxation		8,083	11,962	5,14
Minority shareholders' interest		73	92	13
Profit for the year*		8,010	11,870	5,00
Dividend requirements on preference shares*		2	2	
Profit for the year applicable to ordinary shares*		8,008	11,868	5,00
Profit per ordinary share - cents				
Basic	11	35.70	54.85	25.8
Diluted	11	35.48	54.48	25.6
Dividends per ordinary share - cents	10	22.0	20.5	20.
Average number outstanding of 25 cents ordinary shares (in millions)		22,436	21,638	19,38

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* A summary of the adjustments to profit for the year of the Group which would be required if generally accepted accounting principles in the United States had been applied instead of those generally accepted in the United Kingdom is given in Note 43.

The Notes to Financial Statements are an integral part of this Statement.

CONSOLIDATED BALANCE SHEET

	Note	December 31, 2001		2000	
		($ million)			
Fixed assets					
Intangible assets	19		15,593		16,893
Tangible assets	20		77,410		75,173
Investments					
Joint ventures					
Gross assets		4,661		3,641	
Gross liabilities		800		757	
Net investment	21		3,861		2,884
Associated undertakings	21		5,567		5,455
Other	21		2,619		3,414
			12,047		11,753
Total fixed assets			105,050		103,819
Current assets					
Business held for resale		--		636	
Inventories	22	7,631		9,234	
Trade receivables	23	15,436		17,813	

Other receivables falling due					
Within one year	23	6,552		5,995	
After more than one year	23	4,681		4,610	
Investments	24	450		661	
Cash at bank and in hand		1,358		1,170	
		36,108		40,119	
Current liabilities -- falling due within one year					
Finance debt	25	9,090		6,418	
Trade payables	26	13,129		14,363	
Other accounts payable and accrued liabilities	26	15,395		17,747	
		37,614		38,528	
Net current assets			(1,506)		1,591
Total assets less current liabilities			103,544		105,410
Noncurrent liabilities					
Finance debt	25	12,327		14,772	
Accounts payable and accrued liabilities		3,086		3,842	
Provisions for liabilities and charges					
Deferred taxation	9	1,655		1,822	
Other	27	11,482		10,973	
			28,550		31,409
Net assets			74,994		74,001
Minority shareholders' interest			627		585
BP shareholders' interest*			74,367		73,416
Represented by:					
Capital shares					
Preference			21		21
Ordinary			5,608		5,632
Paid in surplus	29		4,014		3,770
Merger reserve	29		26,983		26,869
Other reserves	29		223		456
Retained earnings	29/30		37,518		36,668
			74,367		73,416

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* A summary of the adjustments to BP shareholders' interest which would be required if generally accepted accounting principles in the United States had been applied instead of those generally accepted in the United Kingdom is given in Note 43.

The Notes to Financial Statements are an integral part of this Balance Sheet.

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note	Years ended December 31, 2001	2000	199
		($ million)		
Net cash inflow from operating activities................	31	22,409	20,416	10,29
Dividends from joint ventures............................		104	645	94
Dividends from associated undertakings...................		528	394	21
Servicing of finance and returns on investments				
Interest received..		256	444	17
Interest paid..		(1,282)	(1,354)	(1,06
Dividends received.......................................		132	42	3
Dividends paid to minority shareholders..................		(54)	(24)	(15
Net cash outflow from servicing of finance and returns on investments................................		(948)	(892)	(1,00
Taxation				
UK corporation tax.......................................		(1,058)	(869)	(55
Overseas tax...		(3,602)	(5,329)	(70
Tax paid...		(4,660)	(6,198)	(1,26
Capital expenditure and financial investment				
Payments for tangible and intangible fixed assets........		(12,142)	(8,837)	(6,37
Payments for fixed assets -- investments.................		(72)	(1,264)	(16
Proceeds from the sale of fixed assets...................	18	2,365	3,029	1,14
Net cash outflow for capital expenditure and financial investment..............................		(9,849)	(7,072)	(5,38
Acquisitions and disposals				
Investments in associated undertakings...................		(586)	(985)	(19
Acquisitions...	17	(1,210)	(6,265)	(10
Net investment in joint ventures.........................		(497)	(218)	(75
Proceeds from the sale of businesses.....................	18	538	8,333	1,29
Net cash (outflow) inflow for acquisitions and disposals..		(1,755)	865	24
Equity dividends paid....................................		(4,827)	(4,415)	(4,13
Net cash inflow (outflow)................................		1,002	3,743	(8
Financing..	31	972	3,413	(95
Management of liquid resources...........................	31	(211)	452	(9
Increase (decrease) in cash..............................	31	241	(122)	96
		1,002	3,743	(8

STATEMENT OF TOTAL RECOGNIZED GAINS AND LOSSES

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Profit for the year	8,010	11,870	5,008
Currency translation differences	(908)	(2,508)	(921)
Total recognized gains and losses relating to the year	7,102	9,362	4,087
Prior year adjustment -- change in accounting policy	--	--	715
Total recognized gains and losses	7,102	9,362	4,802

For a cash flow statement and a statement of comprehensive income prepared on the basis of US GAAP see Note 43 -- US generally accepted accounting principles.

The Notes to Financial Statements are an integral part of these Statements.

STATEMENT OF CHANGES IN BP SHAREHOLDERS' INTEREST

The Company's authorized ordinary share capital at December 31, 2001 and 2000 was 36 billion shares of 25 cents each, amounting to $9 billion. At December 31,1999 the authorized ordinary share capital was 24 billion shares of 25 cents each, amounting to $6 billion. In addition the company has authorized preference share capital of 12,750,000 shares of (pound)1 each ($21 million). Details of movements in share capital are shown in Note 30.

The allotted, called up and fully paid share capital at December 31, was as follows:

	Shares		
	Authorized	Issued	Amount
			($ million)
Non-equity-- preference shares			
8% cumulative first preference shares of(pound)1 each at December 31, 2001, 2000 and 1999	7,250,000	7,232,838	12
9% cumulative second preference shares of(pound)1 each at December 31, 2001, 2000 and 1999	5,500,000	5,473,414	9
Equity -- ordinary shares of 25 cents each			
Authorized			
December 31, 2001	36,000,000,000		

ISSUED	2001 Shares of 25 cents each (thousands)	2001 Amount ($ million)	2000 Shares of 25 cents each (thousands)	2000 Amount ($ million)	1999 Shares of 25 cents each (thousands)
January 1	22,528,747	5,632	19,484,024	4,871	19,366,020
Employee share schemes (a)	33,461	8	38,112	9	66,162
Share dividend plan (b)	--	--	--	--	51,842
ARCO (c)	23,798	7	--	--	--
ARCO acquisition	--	--	3,228,274	807	--
Share buyback (d)	(153,929)	(39)	(221,663)	(55)	--
December 31	22,432,077	5,608	22,528,747	5,632	19,484,024
Paid in surplus					
January 1		3,770		3,684	
Premium on shares issued:					
Employee share schemes		118		250	
ARCO		51		--	
Share dividend plan		--		--	
Share buyback		39		55	
Stamp duty reserve tax		--		(295)	
Qualifying Employee Share Ownership Trust (e)		36		76	
December 31		4,014		3,770	

The Notes to Financial Statements are an integral part of this Statement.

STATEMENT OF CHANGES IN BP SHAREHOLDERS' INTEREST (Concluded)

	2001	2000	1999
	($ million)		
Merger reserve			
January 1	26,869	697	697
ARCO (c)	114	--	--
ARCO acquisition	--	26,172	--

December 31	26,983	26,869	697
	======	======	======
Other reserves			
January 1	456	--	--
ARCO(c)	(117)	--	--
ARCO acquisition	--	456	--
Redemption of ARCO preference shares (f)	(116)	--	--
	------	------	------
December 31	223	456	--
	======	======	======
Retained earnings			
January 1	36,668	34,008	33,555
Exchange adjustment	(908)	(2,508)	(921)
Share dividend plan	--	--	311
Share buyback	(1,281)	(2,001)	--
Qualifying Employee Share Ownership Trust (e)	(36)	(76)	(61)
Profit for the year	8,010	11,870	5,008
Dividends (g)			
Preference (non-equity)	(2)	(2)	(2)
Ordinary (equity)	(4,933)	(4,623)	(3,882)
	------	------	------
December 31	37,518	36,668	34,008
	======	======	======

(a) Employee share schemes. During the year 33,460,856 ordinary shares were issued under the BP, Amoco and Burmah Castrol employee share schemes.

(b) During 1999 there were 51,842,146 BP ordinary shares issued under the share dividend plan at par value, by capitalization of paid in surplus.

(c) ARCO. 10,728,978 ordinary shares were issued in connection with the conversion of ARCO preference shares and a further 13,069,008 ordinary shares were issued in respect of ARCO employee share option schemes.

(d) Share buyback. The Company purchased for cancellation 153,928,949 ordinary shares for a total consideration of $1,281 million.

(e) See Note 33 -- Employee share schemes.

(f) Redemption of ARCO preference shares. A cash tender offer was made in March 2001 for the outstanding ARCO preference shares.

(g) See Note 10 -- Dividends per ordinary share.

(h) See Note 30 -- Retained earnings.

(i) Voting on substantive resolutions tabled at a general meeting is on a poll. On a poll, shareholders present in person or by proxy have two votes for every (pound)5 in nominal amount of the first and second preference shares held and one vote for every ordinary share held. On a show of hands vote on other resolutions (procedural matters) at a general meeting, shareholders present in person or by proxy have one vote each.

In the event of the winding up of the Company preference shareholders would be entitled to a sum equal to the capital paid up on the preference shares plus an amount in respect of accrued and unpaid dividends and a premium equal to the higher of (i) 10% of the capital paid up on the preference shares and (ii) the excess of the average market price of such shares on the London Stock Exchange during the previous six months over par value.

The Notes to Financial Statements are an integral part of this Statement.

NOTES TO FINANCIAL STATEMENTS

Note 1 -- Accounting policies

Accounting standards

These accounts are prepared in accordance with applicable UK accounting standards. Two new Financial Reporting Standards: No.17 'Retirement Benefits' (FRS 17) and No.18 'Accounting Policies' (FRS 18) are effective for the Group's 2001 year end reporting. The accounts contain the transitional disclosures required by FRS 17. The adoption of FRS 18 has had no effect on the results for the year nor required any restatement of prior year comparatives.

Basis of preparation

The Group's main activities are the exploration and production of crude oil and natural gas; the marketing and trading of natural gas and power; the refining, marketing, supply and transportation of petroleum products; and the manufacturing and marketing of petrochemicals.

The preparation of accounts in conformity with UK generally accepted accounting practice requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the accounts and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from these estimates.

Group consolidation

The Group financial statements comprise a consolidation of the accounts of the parent Company and its subsidiary undertakings (subsidiaries). The results of subsidiaries acquired or sold are consolidated for the periods from or to the date on which control passes.

An associated undertaking (associate) is an entity in which the Group has a long-term equity interest and over which it exercises significant influence. The consolidated financial statements include the Group proportion of the operating profit or loss, exceptional items, inventory holding gains or losses, interest expense, taxation and net assets of associates (the equity method).

A joint venture is an entity in which the Group has a long-term interest and shares control with one or more co-venturers. The consolidated financial statements include the Group proportion of turnover, operating profit or loss, exceptional items, inventory holding gains or losses, interest expense, taxation, gross assets and gross liabilities of the joint venture (the gross equity method).

Certain of the Group's activities are conducted through joint arrangements and are included in the consolidated financial statements in proportion to the Group's interest in the income, expenses, assets and liabilities of these joint arrangements.

On the acquisition of a subsidiary, or of an interest in a joint venture or associate, fair values reflecting conditions at the date of acquisition are attributed to the identifiable net assets acquired. When the cost of acquisition exceeds the fair values attributable to the Group's share of such net assets the difference is treated as purchased goodwill. This is capitalized and amortized over its estimated useful economic life, limited to a maximum period of 20 years.

Where an interest in a separate business of an acquired entity is held temporarily pending disposal, it is carried on the balance sheet at its estimated net proceeds of sale.

Note 1 -- Accounting policies (continued)

Accounting convention

The accounts are prepared under the historical cost convention. Historical cost accounts show the profits available to shareholders and are the most appropriate basis for presentation of the Group's balance sheet. Profit or loss determined under the historical cost convention includes inventory holding gains or losses and, as a consequence, does not necessarily reflect underlying trading results.

Replacement cost

The results of individual businesses and geographical areas are presented on a replacement cost basis. Replacement cost operating results exclude inventory holding gains or losses and reflect the average cost of supplies incurred during the year, and thus provide insight into underlying trading results. Inventory holding gains or losses represent the difference between the replacement cost of sales and the historical cost of sales calculated using the first-in, first-out, method.

Inventory valuation

Inventories are valued at cost to the Group using the first-in, first-out, method or at net realizable value, whichever is the lower. Stores are stated at or below cost calculated mainly using the average method.

Revenue recognition

Revenues associated with the sale of oil, natural gas liquids, liquefied natural gas, petroleum and chemical products and all other items are recognized when the title passes to the customer. Generally, revenues from the production of natural gas and oil properties in which the Group has an interest with other producers, are recognized on the basis of the Group's working interest in those properties (the entitlement method). Differences between the production sold and the Group's share of production are not significant.

Foreign currencies

On consolidation, assets and liabilities of subsidiaries are translated into US dollars at closing rates of exchange. Income and cash flow statements are translated at average rates of exchange. Exchange differences resulting from the retranslation of net investments in subsidiaries, joint ventures and associates at closing rates, together with differences between income statements translated at average rates and at closing rates, are dealt with in reserves. Exchange gains and losses arising on long-term foreign currency borrowings used to finance the Group's foreign currency investments are also dealt with in reserves. All other exchange gains or losses on settlement or translation at closing rates of exchange of monetary assets and liabilities are included in the determination of profit for the year.

Derivative financial instruments

The Group uses derivative financial instruments (derivatives) to manage certain exposures to fluctuations in foreign currency exchange rates and interest rates, and to manage some of its margin exposure from changes in oil and natural gas prices. Derivatives are also traded in conjunction with these risk management activities.

The purpose for which a derivative contract is used is identified at inception. To qualify as a derivative for risk management, the contract must be in accordance with established guidelines which ensure that it is effective in achieving its objective. All contracts not identified at inception as being for the purpose of risk management are designated as being held for trading purposes and accounted for using the fair value method, as are all oil price derivatives.

Note 1 -- Accounting policies (continued)

The Group accounts for derivatives using the following methods:

Fair value method: derivatives are carried on the balance sheet at fair value ('marked to market') with changes in that value recognized in earnings of the period. This method is used for all derivatives which are held for trading purposes. Interest rate contracts traded by the Group include futures, swaps, options and swaptions. Foreign exchange contracts traded include forwards and options. Oil and natural gas price contracts traded include swaps, options and futures.

Accrual method: amounts payable or receivable in respect of derivatives are recognized ratably in earnings over the period of the contracts. This method is used for derivatives held to manage interest rate risk. These are principally swap agreements used to manage the balance between fixed and floating interest rates on long-term finance debt. Other derivatives held for this purpose may include swaptions and futures contracts. Amounts payable or receivable in respect of these derivatives are recognized as adjustments to interest expense over the period of the contracts. Changes in the derivative's fair value are not recognized.

Deferral method: gains and losses from derivatives are deferred and recognized in earnings or as adjustments to carrying amounts, as appropriate, when the underlying debt matures or the hedged transaction occurs. This method is used for derivatives used to convert non-US dollar borrowings into US dollars, to hedge significant non-US dollar firm commitments or anticipated transactions, and to manage some of the Group's exposure to natural gas price fluctuations. Derivatives used to convert non-US dollar borrowings into US dollars include foreign currency swap agreements and forward contracts. Gains and losses on these derivatives are deferred and recognized on maturity of the underlying debt, together with the matching loss or gain on the debt. Derivatives used to hedge significant non-US dollar transactions include foreign currency forward contracts and options and to hedge natural gas price exposures include swaps, futures and options. Gains and losses on these contracts and option premia paid are also deferred and recognized in the income statement or as adjustments to carrying amounts, as appropriate, when the hedged transaction occurs.

Where derivatives used to manage interest rate risk or to convert non-US dollar debt or to hedge other anticipated cash flows are terminated before the underlying debt matures or the hedged transaction occurs, the resulting gain or loss is recognized on a basis that matches the timing and accounting treatment of the underlying debt or hedged transaction. When an anticipated transaction is no longer likely to occur or finance debt is terminated before maturity, any deferred gain or loss that has arisen on the related derivative is recognized in the income statement together with any gain or loss on the terminated item.

Depreciation

Oil and gas production assets are depreciated using a unit-of-production method based upon estimated proved reserves. Other tangible and intangible assets are depreciated on the straight line method over their estimated useful lives. The average estimated useful lives of refineries are 20 years, chemicals manufacturing plants 20 years and service stations 15 years. Other intangibles are amortized over a maximum period of 20 years.

The Group undertakes a review for impairment of a fixed asset or goodwill if events or changes in circumstances indicate that the carrying amount of the fixed asset or goodwill may not be recoverable. To the extent that the carrying amount exceeds the recoverable amount, that is, the higher of net realizable value and value in use, the fixed asset or goodwill is written down to its recoverable amount. The value in use is determined from estimated discounted future net cash flows.

Note 1 -- Accounting policies (continued)

Maintenance expenditure

Expenditure on major maintenance, refits or repairs is capitalized where it enhances the performance of an asset above its originally assessed standard of performance; replaces an asset or part of an asset which was separately depreciated and which is then written off; or restores the economic benefits of an asset which has been fully depreciated. All other maintenance expenditure is charged to income as incurred.

Exploration expenditure

Exploration expenditure is accounted for in accordance with the successful efforts method. Exploration and appraisal drilling expenditure is initially capitalized as an intangible fixed asset. When proved reserves of oil and natural gas are determined and development is sanctioned, the relevant expenditure is transferred to tangible production assets. All exploration expenditure determined as unsuccessful is charged against income. Exploration licence acquisition costs are amortized over the estimated period of exploration. Geological and geophysical exploration costs are charged against income as incurred.

Decommissioning

Provision for decommissioning is recognized in full at the commencement of oil and natural gas production. The amount recognized is the present value of the estimated future expenditure determined in accordance with local conditions and requirements. A corresponding tangible fixed asset of an amount equivalent to the provision is also created. This is subsequently depreciated as part of the capital costs of the production and transportation facilities. Any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the fixed asset.

Petroleum revenue tax

The charge for petroleum revenue tax is calculated using a unit-of-production method.

Changes in unit-of-production factors

Changes in factors which affect unit-of-production calculations are dealt with prospectively, not by immediate adjustment of prior years' amounts.

Environmental liabilities

Environmental expenditures that relate to current or future revenues are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations and that do not contribute to current or future earnings are expensed.

Liabilities for environmental costs are recognized when environmental assessments or clean-ups are probable and the associated costs can be reasonably estimated. Generally, the timing of these provisions coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites. The amount recognized is the best estimate of the expenditure required. Where the liability will not be settled for a number of years the amount recognized is the present value of the estimated future expenditure.

Leases

Assets held under leases which result in Group companies receiving substantially all risks and rewards of ownership (finance leases) are capitalized as tangible fixed assets at the estimated present value of underlying lease payments. The corresponding finance lease obligation is included with borrowings. Rentals under operating leases are charged against income as incurred.

Note 1 -- Accounting policies (concluded)

Research

Expenditure on research is written off in the year in which it is incurred.

Interest

Interest is capitalized gross during the period of construction where it relates either to the financing of major projects with long periods of development or to dedicated financing of other projects. All other interest is charged against income.

Pensions and other postretirement benefits

The cost of providing pensions and other postretirement benefits is charged to income on a systematic basis, with pension surpluses and deficits amortized over the average expected remaining service lives of current employees. The difference between the amounts charged to income and the contributions made to pension plans is included within other provisions or debtors as appropriate. The amounts accrued for other postretirement benefits and unfunded pension liabilities are included within other provisions.

Deferred taxation

Deferred taxation is calculated, using the liability method, in respect of timing differences arising primarily from the difference between the accounting and tax treatments of both depreciation and petroleum revenue tax. Provision is made or recovery anticipated where timing differences are expected to reverse in the foreseeable future.

Discounting

The unwinding of the discount on provisions is included within interest expense. Any change in the amount recognized for environmental and other provisions arising through changes in discount rates is included within interest expense.

Comparative figures

Information for 2000 has been restated to reflect the transfer of the natural gas liquids business from Refining and Marketing to Gas and Power. In addition, certain prior year figures have been restated to conform with the 2001 presentation.

Note 2 -- Turnover

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Sales and operating revenue	208,299	168,709	91,891
Customs duties and sales taxes	34,081	20,647	8,325
	174,218	148,062	83,566

Note 3 -- Production taxes

	Years ended December 31,		
	2001	2000	1999
	($ million)		
UK petroleum revenue tax	600	707	237
Overseas production taxes	1,089	1,354	780
	1,689	2,061	1,017

F-11

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 4 -- Distribution and administration expenses

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Distribution	9,852	7,514	5,031
Administration	1,066	1,817	1,033
	10,918	9,331	6,064

Distribution and administration expenses for 2001 include Atlantic Richfield Company (ARCO), Burmah Castrol and the European fuels business for the full year, whereas for 2000 their costs were only included for part of the year, from April 14, July 7 and August 1, respectively.

Note 5 -- Other income

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Income from other fixed asset investments	208	202	66
Other interest and miscellaneous income	486	603	348
	694	805	414
Income from investments publicly traded included above	32	8	14

Note 6 -- Exceptional items

Exceptional items comprise profit (loss) on sale of fixed assets and businesses or termination of operations and restructuring costs, as follows:

Years ended December 31,		
2001	2000	1999
($ million)		

Profit on sale of businesses or termination of operations -- Group	182	341	427
-- Joint ventures	--	--	42
Loss on sale of businesses or termination of operations -- Group	(250)	(209)	(106)
	(68)	132	363
Profit on sale of fixed assets -- Group	948	535	84
-- Joint ventures	--	24	--
Loss on sale of fixed assets -- Group	(343)	(471)	(784)
-- Associated undertakings	(2)	--	--
	603	88	(700)
	535	220	(337)
Restructuring costs -- Group	--	--	(1,900)
-- Joint ventures	--	--	(43)
Exceptional items	535	220	(2,280)
Taxation (charge) credit:			
Sale of businesses or termination of operations	(50)	(181)	(21)
Sale of fixed assets	(455)	(111)	(29)
Restructuring costs	--	--	280
Exceptional items, net of tax	30	(72)	(2,050)

Note 6 -- Exceptional items (concluded)

Sales of businesses or termination of operations

The profit on the sale of businesses during 2001 relates to the sale of the group's interest in Vysis. For 2000 the profit is attributable primarily to the divestment by the Group of its common interest in Altura Energy. For 1999 the profit related mainly to the divestment by the Group of its Canadian oil properties and certain chemicals businesses. These included the Verdugt acid salts business; the Plaskon electronics materials business located in the USA and Singapore; and the US Fibers and Yarns business. The profit on sale of businesses by joint ventures in 1999 was mainly attributable to the disposal by the BP/Mobil joint venture of its retail network in Hungary.

For 2001 the loss on sale of businesses or termination of operations relates principally to the sale of the group's Carbon Fibers business and the write-off of assets following the closure or exit from certain chemicals activities. The loss during 2000 arose from the subvention of bank loans to its paraxylene joint venture in Singapore. The loss during 1999 arose from the closure of this joint venture.

Sale of fixed assets

The profit on the sale of fixed assets in 2001 includes the profit from the divestment of the refineries at Mandan, North Dakota, and Salt Lake City, Utah; the group's interest in the Alliance and certain other pipeline systems in the

USA; and BP's interest in the Kashagan discovery in Kazakhstan. For 2000 the profit on sale of fixed assets included the disposal of the Alliance refinery, located in Belle Chasse, Louisiana, the profit from the divestment of a 10% interest in certain exploration and production interests in Trinidad and the profit from the sale of other exploration and production interests, mainly in the UK and USA. The profit on the sale of fixed assets in 1999 included the Federal Trade Commission-mandated sale of distribution terminals and service stations in the USA, the divestment by the Group of its interest in an olefins cracker at Wilton in the UK and the sale and leaseback of US railcars.

The loss on sale of fixed assets in 2001 arises from a number of transactions. For 2000 the loss relates principally to the divestment by the Group of its interests in the Quiriquire and Guarapiche fields in Venezuela. The major element of the loss in 1999 was the disposal by the Group of its interest in the Pedernales oil field in Venezuela.

Additional information on the sale of businesses and fixed assets is given in Note 18 -- Disposals.

Restructuring costs

These costs arose from restructuring activity across the Group following the merger of BP and Amoco at the end of 1998 and relate predominantly to the Group's US operations. The major elements of the restructuring charges comprise employee severance costs ($1,212 million) and provisions to cover future rental payments on surplus leasehold office accommodation and other property ($297 million). During 1999, some 16,000 employees left the Group through severance or outsourcing arrangements. Also included in the restructuring charges are office closure costs, contract termination payments and asset write-downs. The cash outflow for these restructuring charges during 1999 was $976 million and during 2000 was $446 million.

Note 7 -- Interest expense

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Bank loans and overdrafts	119	154	119
Other loans (a)	1,111	1,221	854
Finance leases	78	107	75
	1,308	1,482	1,048
Capitalized at 5% (2000 7% and 1999 6%)	81	119	43
Group	1,227	1,363	1,005
Joint ventures	70	78	70
Associated undertakings	135	140	131
Unwinding of discount on provisions	196	189	130
Change in discount rate for provisions	42	--	(20)
Total charged against profit	1,670	1,770	1,316

(a) Interest expense includes a charge of $62 million (2000 $111 million and 1999 $24 million) relating to early redemption of debt.

Note 8 -- Depreciation and amounts provided

Included in the income statement under the following headings:

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Depreciation and amortization of goodwill and other intangibles			
Replacement cost of sales	7,367	6,403	4,185
Distribution	1,221	707	408
Administration	94	87	115
Exceptional items	--	--	258
	8,682	7,197	4,966
Depreciation of capitalized leased assets included above	65	79	70
Amounts provided against fixed asset investments			
Exceptional items	--	--	84
Replacement cost of sales	68	252	(1)
	68	252	83

The charge for depreciation and amortization of goodwill in 2001 includes $175 million for the impairment of the Venezuelan Lake Maracaibo operation.

For 2000 the charge includes $61 million for the write-down of Chemicals and Exploration and Production assets. In addition, for 2000 $181 million was provided against the Group's chemicals investment in Indonesia as a result of the weak business environment in the region.

Note 8 -- Depreciation and amounts provided (concluded)

The rationalization of office and other facilities in 1999 following the merger resulted in the write-off of redundant IT and other office equipment and furnishings. This charge of $258 million has been included within exceptional items. In addition for 1999 the charge for depreciation includes $100 million for the impairment of the Badami field in Alaska and $123 million for the write-down of various Chemicals and Refining and Marketing assets.

In assessing the value in use of potentially impaired assets, a discount rate of 9% has been used. This is the rate used by the Company for investment appraisal.

Note 9 -- Taxation

Charge for taxation

	Years ended December 31, 2001	2000	1999
	($ million)		
United Kingdom corporation tax:			
Current at 30.0% (2000 at 30.0% and 1999 at 30.25%)	1,666	1,505	875
Overseas tax relief	(678)	(310)	(363)
	988	1,195	512
Deferred at 30.0% (2000 at 30.0% and 1999 at 30.0%)	(48)	12	91
	940	1,207	603
Overseas:			
Current	3,846	3,704	1,143
Deferred	(66)	(124)	30
Joint ventures	94	57	5
Associated undertakings	203	128	99
	4,077	3,765	1,277
Taxation charge for the year	5,017	4,972	1,880

Included in the charge for the year is a charge of $505 million (2000 $292 million charge and 1999 $230 million credit) relating to exceptional items.

Note 9 -- Taxation (continued)

Reconciliation of the UK statutory tax rate to the effective tax rate of the Group on replacement cost profit before exceptional items

	Years ended December 31, 2001	2000	1999
	(% of profit before tax)		
United Kingdom statutory tax rate	30	30	30

Increase (decrease) resulting from:			
Current year timing differences not provided (including current year losses unrelieved/prior year losses utilized)	(6)	(5)	(10)
(Relief for inventory holding losses)/tax on inventory holding gains	(1)	1	2
Overseas taxes at higher rates	8	7	5
Tax credits	(2)	(4)	--
Acquisition amortization	4	3	--
Other	(2)	(3)	1
Effective tax rate on replacement cost profit before exceptional items	31	29	28

Further information presented in compliance with the requirements of FASB Statement of Financial Accounting Standards No. 109 -- 'Accounting For Income Taxes' is set out below.

Provisions for deferred taxation

	Provisions		Gross potential liability	
	Years ended December 31,			
	2001	2000	2001	2000
	($ million)			
Analysis of movements during the year:				
At January 1	1,822	1,783	10,595	7,953
Exchange adjustments	(56)	(139)	(140)	(287)
Acquisitions	3	323	3	1,404
Charge (credit) for the year	(114)	(112)	1,244	1,564
Deletions/transfers	--	(33)	--	(39)
At December 31	1,655	1,822	11,702	10,595
of which -- United Kingdom	1,055	1,141	2,071	2,181
-- Overseas	600	681	9,631	8,414
Analysis of provision:				
Depreciation	2,527	2,641	12,672	11,384
Petroleum revenue tax	(383)	(337)	(383)	(337)
Other timing differences	(489)	(482)	(587)	(452)
	1,655	1,822	11,702	10,595

If provision for deferred taxation had been made on the basis of the gross potential liability, the overseas taxation charge for the year would have increased by $1,358 million (2000 $1,676 million and 1999 $442 million).

Deferred taxation is not generally provided in respect of liabilities which may arise on the distribution of accumulated reserves of overseas subsidiaries, joint ventures and associated undertakings.

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 9 -- Taxation (concluded)

The Group has adopted Financial Reporting Standard No. 19 'Deferred Tax' with effect from January 1, 2002. If this new standard had been applied to the reported results for 2001, the tax charge for the year would have increased by $1,358 million to $6,375 million. In addition, at December 31, 2001 there would have been a reduction of $9,050 million in shareholders' funds and capital employed. This represents the difference between the gross potential and the restricted liability amounts for the Group shown above ($10,047 million net of the additional goodwill arising on acquisitions in 2000 of $1,081 million) and $84 million for joint ventures and associated undertakings.

Effective tax rate

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Analysis of profit before taxation:			
United Kingdom	2,333	3,426	1,663
Overseas	10,767	13,508	5,363
	13,100	16,934	7,026
Taxation	5,017	4,972	1,880
Effective tax rate	38%	29%	27%

The following relates the United Kingdom statutory tax rate to the effective tax rate of the Group based on profit before taxation:

	Years ended December 31,		
	2001	2000	1999
	(% of profit before tax)		
United Kingdom statutory tax rate	30	30	30
Increase (decrease) resulting from:			
Current year timing differences not provided	(11)	(5)	(9)
(Prior year losses utilized) current year losses unrelieved	4	2	2
(Inventory holding gains not taxed) no relief for inventory holding losses	3	(1)	(5)
Overseas taxes at higher rates	9	7	5

Tax credits	(3)	(4)	--
Acquisition amortization	6	3	1
Other	--	(3)	3
Effective tax rate	38	29	27

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 10 -- Dividends per ordinary share

	Years ended December 31,								
	2001	2000	1999	2001	2000	1999	2001	2000	1999
	(pence per share)			(cents per share)			($ million)		
First quarterly	3.665	3.220	3.069	5.25	5.00	5.00	1,178	1,133	970
Second quarterly	3.911	3.352	3.112	5.50	5.00	5.00	1,235	1,128	970
Third quarterly	3.805	3.602	3.033	5.50	5.25	5.00	1,232	1,185	971
Fourth quarterly	4.055	3.617	3.125	5.75	5.25	5.00	1,288	1,177	971
	15.436	13.791	12.339	22.00	20.50	20.00	4,933	4,623	3,882

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 11 -- Profit per ordinary share

	Years ended December 31,		
	2001	2000	1999
	(cents per share)		
Basic earnings per share	35.70	54.85	25.82
Diluted earnings per share	35.48	54.48	25.68

The calculation of basic earnings per ordinary share is based on the profit attributable to ordinary shareholders, i.e. profit for the year less preference dividends, related to the weighted average number of ordinary shares in issue during the year. The profit attributable to ordinary shareholders is $8,008 million (2000 $11,868 million and 1999 $5,006 million). The average number of shares outstanding excludes the shares held by the Employee Share Ownership Plans.

The calculation of diluted earnings per share is based on profit attributable to ordinary shareholders as for basic earnings per share. However, the number of shares outstanding is adjusted to show the potential dilution if employee share options are converted into ordinary shares. The number of ordinary shares outstanding for basic and diluted earnings per share may be reconciled as follows:

	Years ended December 31,		
	2001	2000	1999
	(shares million)		
Weighted average number of ordinary shares....................	22,436	21,638	19,386
Ordinary shares issuable under employee share schemes..........	138	145	111
	22,574	21,783	19,497

In addition to basic earnings per share based on the historical cost profit for the year, a further measure, based on replacement cost profit before exceptional items, is provided as it is considered that this measure gives an indication of underlying performance.

	Years ended December 31,		
	2001	2000	1999
	(cents per share)		
Profit for the year..	35.70	54.85	25.82
Inventory holding (gains) losses...........................	8.47	(3.36)	(8.91)
Replacement cost profit for the year.......................	44.17	51.49	16.91
Exceptional items, net of tax..............................	(0.14)	0.33	10.57
Replacement cost profit before exceptional items...........	44.03	51.82	27.48

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 12 -- Quarterly results of operations (unaudited)

	Group turnover	Historical cost profit before interest and tax	Profit (loss)	Profit (loss) per ordinary share

		($ million)		(cents)
Year ended December 31, 2001				
First quarter	45,700	5,479	3,304	14.70
Second quarter	48,689	5,183	3,171	14.12
Third quarter	43,886	3,536	1,940	8.66
Fourth quarter	37,114	572	(405)	(1.78)
Total	175,389	14,770	8,010	35.70
Year ended December 31, 2000				
First quarter	33,091	4,336	3,085	15.88
Second quarter	39,027	4,711	3,024	13.59
Third quarter	44,862	5,377	3,351	14.85
Fourth quarter	44,846	4,280	2,410	10.53
Total	161,826	18,704	11,870	54.85

Note 13 -- Rental expense under operating leases

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Minimum rentals:			
Tanker charters	393	361	357
Plant and machinery	530	471	509
Land and buildings	355	343	271
	1,278	1,175	1,137
Less: Rentals from sub-leases	(165)	(185)	(178)
	1,113	990	959

Note 14 -- Research and development

Expenditure on research and development amounted to $385 million (2000 $434 million and 1999 $310 million).

Note 15 -- Auditors' remuneration

	Years ended December 31,					
	2001		2000		1999	
	UK	Total	UK	Total	UK	Total
	($ million)					
Audit fees -- Ernst & Young:						
Group audit	5	13	6	15	6	14
Local statutory audit and quarterly review	3	11	3	13	1	6
	8	24	9	28	7	20
Fees for other services -- Ernst & Young						
Acquisitions and disposals	16	20	8	9	3	5
Taxation services	9	28	2	14	1	6
Assurance services	4	11	5	10	4	5
Consultancy	--	--	5	18	7	20
	29	59	20	51	15	36

Group audit fees for 2000 include $1 million for excess of actual over estimated fees for 1999.

The audit fees payable to Ernst & Young are reviewed by the Audit Committee in the context of other global companies for cost effectiveness. The committee also reviews the nature and extent of non-audit services to ensure that independence is maintained.

Ernst & Young is selected to provide assurance services in addition to their statutory audit duties where their expertise and experience of BP are important. Most of this work is of an audit nature. For the same reasons, it is beneficial to the Group to use Ernst & Young for due diligence work relating to acquisitions and disposals. The tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young relative to that of other potential service providers. These services are for a fixed term.

Fees to major firms of accountants other than Ernst & Young for non-audit services amounted to $305 million (2000 $275 million and 1999 $160 million).

Note 16 -- Currency exchange gains and losses

Accounted net foreign currency exchange loss included in the determination of profit for the year amounted to $12 million (2000 $30 million gain and 1999 $17 million gain).

Note 17 -- Acquisitions

	2001				2
			Fair value adjustments		
	Book value on acquisitions	Accounting policy alignment	Revaluations	Fair value	F va
			($ million)		
Intangible fixed assets...........	198	--	(4)	194	2,
Tangible fixed assets.............	386	87	368	841	21,
Fixed assets -- investments........	6	--	12	18	4,
Businesses held for resale.........	--	--	--	--	5,
Current assets (excluding cash)....	402	2	24	428	6,
Cash at bank and in hand..........	--	--	--	--	1,
Finance debt......................	(55)	--	--	(55)	(7,
Other creditors...................	(221)	--	7	(214)	(7,
Deferred taxation.................	(3)	--	--	(3)	(
Other provisions..................	(170)	--	(1)	(171)	(3,
Net investment in Erdoelchemie.....	(170)	--	--	(170)	
Net assets acquired...............	373	89	406	868	24,
Minority interests................				--	(1,
Goodwill..........................				48	11,
Consideration.....................				916	33,

Acquisitions in 2001. During the year the Group acquired the 50% of Erdoelchemie, a petrochemicals business based in Germany, it did not already own. In addition a number of minor acquisitions were made. All these business combinations have been accounted for using the acquisition method of accounting. The assets and liabilities acquired as part of the 2001 acquisitions are shown in the above table in aggregate. The fair value of tangible fixed assets has been estimated by determining the net present value of future cash flows. No significant adjustments were made to the other acquired assets and liabilities.

Pro forma effects as required by US GAAP are not presented as they would not materially change reported consolidated results of operations.

Acquisitions in 2000. In the year the Company acquired Atlantic Richfield Company (ARCO) and Burmah Castrol p.l.c. (Burmah Castrol) and the 18% minority interest in Vastar Resources Inc. (Vastar), a subsidiary of ARCO. The Company also purchased most of ExxonMobil's assets used by the fuels refining and marketing operation in Europe and made a number of minor acquisitions.

ARCO was acquired in April 2000. The total consideration for the acquisition was $27,506 million, including acquisition expenses of $79 million, and was effected by the issue of approximately 3,335 million BP ordinary shares. In 2001, a cash tender offer was made for the outstanding ARCO preference stock. The cash paid on redemption, $116 million, approximated the amount attributable to the ARCO preference stock in the original determination of the consideration.

The fair values of the assets and liabilities of ARCO included in the accounts for the year ended December 31, 2000 have been subject to further investigation and review during 2001, as permitted by Financial Reporting Standard No. 7 'Fair Values in Acquisition Accounting'. The revisions to the previously reported fair values are set out below.

Note 17 -- Acquisitions (concluded)

	Fair value as previously reported	Revisions	Final fair value
		($ million)	
Intangible fixed assets	2,549	--	2,549
Tangible fixed assets	19,829	(911)	18,918
Fixed assets -- investments	3,005	--	3,005
Net assets of businesses held for resale	5,290	--	5,290
Current assets (excluding cash)	3,668	--	3,668
Cash at bank and in hand	994	--	994
Finance debt	(6,796)	--	(6,796)
Other creditors	(3,475)	814	(2,661)
Deferred taxation	(323)	--	(323)
Other provisions	(3,009)	--	(3,009)
Net assets acquired	21,732	(97)	21,635
Minority interests	(1,595)	--	(1,595)
Goodwill	7,369	97	7,466
Consideration	27,506	--	27,506

Tangible fixed assets. The fair value attributed to certain exploration and production assets has been revised following further technical studies.

Other creditors. Liabilities for taxation have been revised following a review of outstanding liabilities.

BP completed the purchase of the minority interest in Vastar on September 15, 2000 for a total consideration of $1,618 million. This was settled in cash and included expenses of $9 million and $94 million for the buy-out of employee share options.

On July 7, 2000, the Company declared its cash offer for Burmah Castrol unconditional. The total consideration was $4,909 million. Apart from the issue of $130 million of loan notes the balance of the consideration was settled in cash and included expenses of $16 million. The Company also acquired a further 20% interest in Castrol India at a cost of $178 million. This was settled in 2001.

On dissolution of the pan-European refining and marketing joint venture, BP acquired most of the ExxonMobil assets used by the fuels operation for $1,479 million.

The Group undertook a number of other acquisitions in 2000 for an aggregate consideration of $100 million.

Acquisitions in 1999. During the year the Group acquired the oustanding 83% of ProGas, a major Canadian natural gas supply aggregator, and 50% of Solarex, a manufacturer and developer of photovoltaic products and systems, it did not already own. Also in 1999 the Group purchased APEX, a solar electric company based in Montpellier, France.

Note 18 -- Disposals

Divestments in 2001. During the year the Group made a number of disposals. The major transactions included the sale of the group's interest in the Kashagan discovery in Kazakhstan; the divestment of the refineries at Mandan, North Dakota, and Salt Lake City, Utah; the sale of interests in the Alliance and certain other pipeline systems in the USA; and the disposal of the Group's majority interest in Vysis.

Note 18 -- Disposals (continued)

At December 31, 2000 the Foseco, Fosroc and Sericol speciality chemicals businesses which were acquired as part of the Burmah Castrol acquisition were categorized as businesses held for resale. Foseco was sold in July 2001, but the other two businesses will now be retained and have been fully consolidated from July 1, 2001.

A number of chemicals activities were either sold or terminated during 2001. Included in the businesses sold was the Carbon Fibers business.

The Group reduced its investment in Lukoil, which was acquired as part of the ARCO acquisition, from 7% to 4% through the sale of 23.5 million shares.

To fulfil undertakings given to the European Commission at the time of the ARCO acquisition, BP sold certain UK Southern North Sea natural gas interests in April 2001.

Divestments in 2000. As a condition of the acquisition of ARCO in 2000 BP was required to divest ARCO's Alaskan businesses and certain pipeline interests in the Lower 48. These operations were sold for aggregate proceeds of $6,803 million. No profit or loss arose on these disposals.

Divestments in 1999. Disposals in 1999 included the sale of the Group's Canadian oil properties; the divestment of its interest in the Pedernales oil field in Venezuela; the Federal Trade Commission-mandated sale of distribution terminals and service stations in the USA and certain chemicals activities. These included the Verdugt acid salts business; its interest in an olefins cracker at Wilton in the UK; the Plaskon electronics materials business located in the USA and Singapore; the US Fibers and Yarns business; and the sale and leaseback of US railcars. In addition the Group incurred a loss on the closure of its paraxylene joint venture in Singapore.

Other major disposals during 2000 were the sale of the Group's common interest in Altura Energy; the sale of the Alliance refinery; the divestment of exploration and production interests in Trinidad, the UK, USA and Venezuela; and the sale of the Southern Company Energy Marketing.

Total proceeds received for disposals represent the following amounts shown in the cash flow statement:

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Proceeds from the sale of businesses.................	538	8,333	1,292
Proceeds from the sale of fixed assets...............	2,365	3,029	1,149
	2,903	11,362	2,441

Note 18 -- Disposals (concluded)

The disposals comprise the following:

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Intangible assets..................................	183	458	199
Tangible assets....................................	1,481	3,224	2,340
Fixed asset -- investments.........................	898	673	206
Net assets of businesses held for resale............	307	5,290	--
Current assets less current liabilities.............	(145)	919	175
Other provisions....................................	(112)	631	(94)
	2,612	11,195	2,826
Profit (loss) on sale of businesses or termination of operations.........................	(68)	132	321
Profit (loss) on sale of fixed assets...............	605	64	(700)
Total consideration.................................	3,149	11,391	2,447
Increase in amounts receivable from disposals........	(246)	(102)	(12)
Cash retained.......................................	--	73	6
Net cash inflow.....................................	2,903	11,362	2,441

Note 19 -- Intangible assets

	Exploration expenditure	Goodwill	Other intangibles	Total
	($ million)			
Cost				
At January 1, 2001	6,106	12,055	755	18,916
Exchange adjustments	(16)	(116)	(6)	(138)
Acquisitions	187	48	7	242
Additions	878	--	92	970
Transfers	(797)	--	(35)	(832)
Fair value adjustments	--	97	--	97
Deletions	(244)	(93)	(8)	(345)
At December 31, 2001	6,114	11,991	805	18,910
Depreciation				
At January 1, 2001	690	882	451	2,023
Exchange adjustments	(6)	(5)	(1)	(12)
Charge for the year	238	1,180	61	1,479
Transfers	(22)	--	11	(11)
Deletions	(120)	(37)	(5)	(162)
At December 31, 2001	780	2,020	517	3,317
Net book amount				
At December 31, 2001	5,334	9,971	288	15,593
At December 31, 2000	5,416	11,173	304	16,893

Note 20 -- Tangible assets

Property, plant and equipment:

	Exploration and Production	Gas and Power	Refining and Marketing	Chemicals	Other businesses and corporate
	($ million)				
Cost					
At January 1, 2001	93,025	1,820	30,280	14,898	1,984

Exchange adjustments	(955)	(57)	(688)	(285)	(16)
Acquisitions	47	3	--	624	167
Additions	7,525	251	2,247	1,017	350
Transfers	797	(13)	25	(32)	259
Fair value adjustments	(911)	--	--	--	--
Deletions	(1,516)	(61)	(2,108)	(432)	(190)
At December 31, 2001	98,012	1,943	29,756	15,790	2,554
Depreciation					
At January 1, 2001	46,274	498	12,661	6,538	863
Exchange adjustments	(543)	(14)	(289)	(121)	(6)
Charge for the year	5,197	46	1,564	537	97
Transfers	22	(6)	23	(12)	142
Deletions	(1,208)	--	(1,106)	(394)	(118)
At December 31, 2001	49,742	524	12,853	6,548	978
Net book amount					
At December 31, 2001	48,270	1,419	16,903	9,242	1,576
At December 31, 2000	46,751	1,322	17,619	8,360	1,121

Assets held under capital leases, capitalized interest and land at net book amount included above:

	Leased assets			Capitalized interest		
	Cost	Depreciation	Net	Cost	Depreciation	Net
		($ million)			($ million)	
At December 31, 2001	1,517	837	680	3,018	1,480	1,538
At December 31, 2000	1,926	1,076	850	2,946	1,395	1,551

		Leasehold land	
	Freehold land	Over 50 years unexpired	Other
		($ million)	
At December 31, 2001	2,279	211	170
At December 31, 2000	2,012	315	151

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 21 -- Fixed assets -- investments

	Associated undertakings						
	Shares	Loans	Share of retained profit	Joint ventures	Loans	Own shares(a)	List investmen
					($ million)		
Cost							
At January 1, 2001	3,196	892	1,791	2,884	476	360	1,5
Exchange adjustments	(23)	(8)	(62)	(6)	(28)	(10)	(
Additions and net movements in joint ventures	237	340	(116)	683	30	33	
Acquisitions	13	--	--	--	5	--	
Transfers	116	309	(91)	308	(284)	--	
Deletions	(253)	(253)	(2)	(8)	(18)	(117)	(2
At December 31, 2001	3,286	1,280	1,520	3,861	181	266	1,2
Amounts provided							
At January 1, 2001	218	206	--	--	43	--	
Exchange adjustments	--	(5)	--	--	--	--	
Provided in the year	--	37	--	--	26	--	
Transfers	--	85	--	--	--	--	
Deletions	--	(22)	--	--	--	--	
At December 31, 2001	218	301	--	--	69	--	
Net book amount							
At December 31, 2001	3,068	979	1,520	3,861	112	266	1,2
At December 31, 2000	2,978	686	1,791	2,884	433	360	1,5

(a) Own shares are held in Employee Share Ownership Plans (ESOPs) to meet the future requirements of the Employee Share Schemes (see Note 33) and prior to award under the Long Term Performance Plan (see Note 34). At December 31, 2001 the ESOPs held 34,005,910 shares (45,514,664 shares at December 31, 2000) for the Employee Share Schemes and 7,673,056 shares (9,506,839 shares at December 31, 2000) for the Long Term Performance Plan. The market value of these shares at December 31, 2001 was $323 million ($443 million at December 31, 2000).

(b) The market value of listed investments at December 31, 2001 was $1,284 million.

(c) Other investments are unlisted.

Note 22 -- Inventories

	December 31, 2001	December 31, 2000
	($ million)	
Petroleum	5,176	6,933
Chemicals	953	1,046
Other	568	504
	6,697	8,483
Stores	934	751
	7,631	9,234
Replacement cost	7,686	9,392

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 23 -- Receivables

	December 31, 2001 Within 1 year	December 31, 2001 After 1 year(a)	December 31, 2000 Within 1 year	December 31, 2000 After 1 year(a)
	($ million)			
Trade receivables	15,436	--	17,813	--
Other receivables:				
Joint ventures	8	--	39	--
Associated undertakings	260	49	98	46
Prepayments and accrued income	2,143	789	2,137	486
Taxation recoverable	335	8	412	--
Pension prepayment	--	3,539	--	3,609
Other	3,806	296	3,309	469
	6,552	4,681	5,995	4,610

Provisions for doubtful debts deducted from Trade receivables amounted to $290 million ($357 million at December 31, 2000).

(a) See Note 43-- US generally accepted accounting principles.

Note 24 -- Current assets -- investments

December 31,

	2001	2000
	($ million)	
Publicly traded -- United Kingdom	49	59
-- Foreign	30	220
	79	279
Not publicly traded	371	382
	450	661
Stock exchange value of publicly traded investments	88	280

Note 25 -- Finance debt

	December 31, 2001		December 31, 2000	
	Within 1 year	After 1 year	Within 1 year	After 1 year
	($ million)			
Bank loans and overdrafts	371(a)	409	895(a)	1,035
Other loans	8,647(a)	10,349	5,420(a)	11,916
Total borrowings	9,018	10,758	6,315	12,951
Obligations under capital leases	72	1,569	103	1,821
	9,090	12,327	6,418	14,772

(a) Amounts due within one year include current maturities of long-term debt.

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 25 -- Finance debt (continued)

Where a borrowing is swapped into another currency, the borrowing is accounted in the swap currency and not in the original currency of denomination. Total borrowings include $264 million ($369 million at December 31, 2000) for the carrying value of currency swaps and forward contracts.

Included within Other loans repayable within one year are US Industrial Revenue/Municipal Bonds of $1,768 million (December 31, 2000 $1,671 million) with maturity periods ranging up to 36 years. They are classified as repayable within one year, as required under UK GAAP, as the bondholders typically have the option to tender these bonds for repayment on interest reset dates. Any bonds that are tendered are usually remarketed and BP has not experienced any significant repurchases. BP considers these bonds to represent long-term funding when assessing the maturity profile of its borrowings.

At December 31, 2001, the Group's share of third party borrowings of joint ventures and associated undertakings was $460 million and $1,136 million respectively. These amounts are not reflected in the Group's debt on the balance sheet.

Analysis of borrowings by year of repayment

	December 31, 2001			December 31, 2000		
	Bank loans and overdrafts	Other loans	Total	Bank loans and overdrafts	Other loans	Total
	($ million)					
Due after 10 years........	42	3,176	3,218	258	3,296	3,554
Due within 6-10 years......	--	3,222	3,222	26	3,402	3,428
5 years.........	150	501	651	24	1,202	1,226
4 years.........	24	1,542	1,566	417	744	1,161
3 years.........	15	626	641	75	1,187	1,262
2 years.........	178	1,282	1,460	235	2,085	2,320
	409	10,349	10,758	1,035	11,916	12,951
1 year..........	371	8,647	9,018	895	5,420	6,315
	780	18,996	19,776	1,930	17,336	19,266

Amounts included above repayable by instalments part of which falls due after five years from December 31, are as follows:

	December 31, 2001	December 31, 2000
	($ million)	
After five years..	120	27
Within five years...	1,071	216
	1,191	243

Interest rates on borrowings repayable wholly or partly more than five years from December 31, 2001 range from 1% to 12% with a weighted average of 6%. The weighted average interest rate on finance debt is 5%.

At December 31, 2001 the Group had substantial amounts of undrawn borrowing facilities available, including committed facilities of $3,400 million expiring in 2002 ($3,450 million at December 31, 2000 expiring in 2001). These facilities are with a number of international banks and borrowings under them would be at pre-agreed rates. Certain of these facilities support the Group's commercial paper programme.

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 25 -- Finance debt (continued)

Analysis of borrowings by currency

	December 31, 2001						Decem
	Fixed rate debt			Floating rate debt			
	Weighted average interest rate	Weighted average time for which rate is fixed	Amount	Weighted average interest rate	Amount	Total	
	(%)	(Years)	($ million)	(%)	($ million)	($ million)	($
US dollars...........	7	8	11,485	2	7,842	19,327	
Sterling.............	--	--	--	4	133	133	
Other currencies......	10	29	122	6	194	316	
Total loans...........			11,607		8,169	19,776	

The Group aims for a balance between floating and fixed interest rates and, in 2001, the proportion of floating rate debt was in the range 32-43% of total net debt outstanding. Aside from debt issued in the US municipal bond markets, interest rates on floating rate debt denominated in US dollars are linked principally to London Inter-Bank Offer Rate (LIBOR), while rates on debt in other currencies are based on local market equivalents. The Group monitors interest rate risk using a process of sensitivity analysis. Assuming no changes to the borrowings and hedges described above, it is estimated that a change of 1% in the general level of interest rates on January 1, 2002 would change 2002 profit before tax by approximately $100 million.

Fair values and carrying amounts of borrowings

	December 31,			
	2001		2000	
	Fair value	Carrying amount	Fair value	Carrying amount
	($ million)			
Short-term borrowings..................	5,185	5,185	3,706	3,706
Long-term borrowings...................	14,875	14,360	15,573	15,299

Total borrowings	20,060	19,545	19,279	19,005

The fair value and carrying amounts of borrowings shown above exclude the effects of currency swaps, interest rate swaps and forward contracts (which are included for presentation in the balance sheet). Long-term borrowings in the above table include debt which matures in the year from December 31, 2001, whereas in the balance sheet long-term debt of current maturity is reported under amounts falling due within one year. Long-term borrowings also include US Industrial Revenue/Municipal Bonds classified on the balance sheet as repayable within one year. The carrying amount of the Group's short-term borrowings, which mainly comprise commercial paper, bank loans and overdrafts, approximate their fair value. The fair value of the Group's long-term borrowings is estimated using quoted prices or, where these are not available, discounted cash flow analyses, based on the Group's current incremental borrowing rates for similar types and maturities of borrowing.

Note 25 -- Finance debt (continued)

Obligations under capital leases

The future minimum lease payments together with the present value of the net minimum lease payments were as follows:

	December 31, 2001
	($ million)
2002	97
2003	159
2004	165
2005	173
2006	177
Thereafter	2,877
	3,648
Less: amount representing lease interest	2,007
Present value of net minimum capital lease payments	1,641
of which -- due within one year	72
-- due after one year	1,569

The following information is presented in compliance with the requirements of US GAAP.

Bank loans and overdrafts and other loans-- long term

	Weighted average interest rate at December 31, 2001	December 31, 2001	December 31, 2000
	(%)	($ million)	
US dollar	7	10,617	12,599
Sterling	6	19	289
Other currencies	10	122	63
		10,758	12,951

Bank loans and overdrafts and other loans -- short term

	December 31, 2001	December 31, 2000
	($ million)	
Current maturities of long-term debt	1,993	938
Commercial paper	4,634	2,943
Bank loans and overdrafts	371	762
Other	2,020	1,672
	9,018	6,315

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 25 -- Finance debt (concluded)

	Weighted average interest rate at December 31, 2001	Weighted average interest rate at December 31, 2000
	(%)	
Commercial paper	2	7
Bank loans, overdrafts and other borrowings	4	8
US Industrial Revenue/Municipal bonds	2	5

Note 26 -- Accounts payable and accrued liabilities

	December 31, 2001		December 31, 2000	
	Within 1 year	After 1 year	Within 1 year	After 1 year
	($ million)			
Trade payables	13,129	--	14,363	--
Other accounts payable and accrued liabilities:				
Joint ventures	21	--	67	--
Associated undertakings	268	4	296	4
Production taxes	254	1,346	347	1,123
Taxation on profits	3,456	--	4,091	2
Social security	63	--	59	--
Accruals and deferred income	4,843	1,029	6,557	1,876
Dividends	1,289	--	1,178	--
Other	5,201	707	5,152	837
	15,395	3,086	17,747	3,842

Note 27 -- Other provisions

	Decommissioning	Environmental	Unfunded pension plans	Other postretirement benefits	Other
	($ million)				
At January 1, 2001	3,001	2,131	1,579	2,726	1,536
Exchange adjustments	(66)	(5)	(63)	--	(14)
Acquisitions	--	33	114	--	24
New provisions	156	180	230	160	438
Unwinding of discount	104	77	--	--	15
Change in discount rate	315	37	--	--	5
Utilized/deleted	(206)	(355)	(117)	(222)	(331)
At December 31, 2001	3,304	2,098	1,743	2,664	1,673

F - 32

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 27 -- Other provisions (concluded)

The Group makes full provision for the future cost of decommissioning oil and natural gas production facilities and related pipelines on a discounted basis at the commencement of production. At December 31, 2001 the provision for the costs of decommissioning these production facilities and pipelines at the end of their economic lives was $3,304 million ($3,001 million at December 31, 2000). The provision has been estimated using existing technology, at current prices and discounted using a real discount rate of 3% (2000 3.5%). These costs are expected to be incurred over the next 30 years. While the provision is based on the best estimate of future costs and the economic lives of the facilities and pipelines, there is uncertainty regarding both the amount of and timing of incurring these costs.

Provisions for environmental remediation are made when a clean-up is probable and the amount reasonably determinable. Generally this coincides with commitment to a formal plan of action or, if earlier, on divestment or closure of inactive sites. The provision for environmental liabilities at December 31, 2001 was $2,098 million ($2,131 million at December 31, 2000). The provision has been estimated using existing technology, at current prices and discounted using a real discount rate of 3% (2000 3.5%). These costs are expected to be incurred over the next 10 years. The extent and cost of future remediation programs are inherently difficult to estimate. They depend on the scale of any possible contamination, the timing and extent of corrective actions, and also the Group's share of liability.

The Group also holds provisions for potential future awards under the long-term performance plans, expected rental shortfalls on surplus properties and sundry other liabilities. To the extent that these liabilities are not expected to be settled within the next three years, the provisions are discounted using a real discount rate of 3% (2000 3.5%).

Note 28 -- Derivative financial instruments

In the normal course of business the Group is a party to derivative financial instruments (derivatives) with off balance sheet risk, primarily to manage its exposure to fluctuations in foreign currency exchange rates and interest rates, including management of the balance between floating rate and fixed rate debt. The Group also manages certain of its exposures to movements in oil and natural gas prices. The underlying economic currency of the Group's cash flows is mainly the US dollar. Accordingly, most of our borrowings are in US dollars, are hedged with respect to the US dollar or swapped into US dollars. Significant non-dollar cash flow exposures are hedged. Gains and losses arising on these hedges are deferred and recognized in the income statement or as adjustments to carrying amounts, as appropriate, only when the hedged item occurs. In addition, we trade derivatives in conjunction with these risk management activities. The results of trading are recognized in income in the current period.

The Group co-ordinates certain key activities on a global basis in order to optimize its financial position and performance. These include the management of the currency, maturity and interest rate profile of borrowing, cash, other significant financial risks and relationships with banks and other financial institutions. International oil and natural gas trading and risk management relating to business operations are carried out by the Group's oil and natural gas trading units.

BP is exposed to financial risks, including market risk, credit risk and liquidity risk, arising from the Group's normal business activities. These risks and the Group's approach to dealing with them are discussed below.

Note 28 -- Derivative financial instruments (continued)

Market risk

Market risks include the possibility that changes in currency exchange rates, interest rates or oil and natural gas prices will adversely affect the value of the Group's financial assets, liabilities or expected future cash flows. Market risks are managed using a range of financial and commodity instruments, including derivatives. We also trade derivatives in conjunction with these risk management activities.

Currency exchange rates. Fluctuations in exchange rates can have significant effects on the Group's reported profit. The effects of most exchange rate fluctuations are absorbed in business operating results through changing cost competitiveness, lags in market adjustment to movements in rates, and conversion differences accounted for on specific transactions. For this reason the total effect of exchange rate fluctuations is not identifiable separately in the Group's reported profit.

The main underlying economic currency of the Group's cash flows is the US dollar and the Group's borrowings are predominantly in US dollars. Our foreign exchange management policy is to minimize economic and material transactional exposures arising from currency movements against the US dollar. The Group co-ordinates the handling of foreign exchange risks centrally, by netting off naturally occurring opposite exposures wherever possible, to reduce the risks, and then dealing with any material residual foreign exchange risks. Significant residual non-dollar exposures are managed using a range of derivatives.

Interest rates. The Group is exposed to interest rate risk on short- and long-term floating rate instruments and as a result of the refinancing of fixed rate finance debt. Consequently, as well as managing the currency and the maturity of debt, the Group manages interest expense through the balance between generally lower-cost floating rate debt, which has inherently higher risk, and generally more expensive, but lower-risk, fixed rate debt. The Group is exposed predominantly to US dollar LIBOR (London Inter-Bank Offer Rate) interest rates as borrowings are mainly denominated in, or are swapped into, US dollars.

The Group uses derivatives to manage the balance between fixed and floating rate debt. During 2001, the proportion of floating rate debt was in the range 32-43% of total net debt outstanding.

Oil and natural gas prices. BP's trading units use financial and commodity derivatives as part of the overall optimization of the value of the Group's equity oil production and as part of the associated trading of crude oil, products and related instruments. They also use financial and commodity derivatives to manage certain of the Group's exposures to price fluctuations on natural gas transactions.

Market risk management and trading. In market risk management and trading, conventional exchange-traded derivative instruments such as futures and options are used as well as non-exchange-traded instruments such as swaps, 'over-the-counter' options and forward contracts.

Where derivatives constitute a hedge, the Group's exposure to market risk created by the derivative is offset by the opposite exposure arising from the asset, liability, cash flow or transaction being hedged. By contrast, where derivatives are held for trading purposes, changes in market risk factors give rise to realized and unrealized gains and losses, which are recognized in the current period.

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 28 -- Derivative financial instruments (continued)

All financial instrument and derivative activity, whether for risk management or trading, is carried out by specialist teams which have the appropriate skills, experience and supervision. These teams are subject to close financial and management control, meeting generally accepted industry practice and reflecting the principles of the Group of Thirty Global Derivatives Study recommendations. A Trading Risk Management Committee has oversight of the quality of internal control in the Group's trading units. Independent control functions monitor compliance with BP's policies. The control framework includes prescribed trading limits that are reviewed regularly by senior management, daily monitoring of risk exposure using value-at-risk principles, marking trading exposures to market and stress testing to assess the exposure to potentially extreme market situations. As part of its approach to ensuring that control over trading is maintained to a high and consistent standard, the Group's business units dealing in the oil, natural gas and financial markets were brought together within a single integrated supply and trading organization during 2001.

Credit risk

Credit risk is the potential exposure of the Group to loss in the event of non-performance by a counterparty. The credit risk arising from the Group's normal commercial operations is controlled by individual operating units within guidelines. In addition, as a result of its use of financial and commodity instruments, including derivatives, to manage market risk, the Group has credit exposures through its dealings in the financial and specialized oil and natural gas markets. The Group controls the related credit risk by entering into contracts only with highly credit-rated counterparties and through credit approvals, limits and monitoring procedures, and does not usually require collateral or other security. Counterparty credit validation, independent of the dealers, is undertaken before contractual commitment.

Liquidity risk

Liquidity risk is the risk that suitable sources of funding for the Group's business activities may not be available. The Group has long-term debt ratings of Aa1 and AA+ assigned respectively by Moody's and Standard and Poor's. The Group has access to a wide range of funding at competitive rates through the capital markets and banks. It co-ordinates relationships with banks, borrowing requirements, foreign exchange requirements and cash management centrally. The Group believes it has access to sufficient funding and also has undrawn committed borrowing facilities to meet currently foreseeable borrowing requirements. At December 31, 2001, the Group had available undrawn committed facilities of $3,400 million ($3,450 million at December 31, 2000). These committed facilities, which are mainly with a number of international banks, expire in 2002. The Group expects to renew the facilities on an annual basis.

With the exception of the table of currency exposures shown on page F-38, short-term debtors and creditors which arise directly from the Group's operations have been excluded from the disclosures contained in this note, as permitted by FRS No. 13 `Derivatives and Other Financial Instruments: Disclosures'.

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 28 -- Derivative financial instruments (continued)

Interest rate risk

The interest rate and currency profile of the financial liabilities of the Group at December 31, 2001, after taking into account the effect of interest rate swaps, currency swaps and forward contracts, is set out below.

	Fixed rate			Floating rate		Interest free	
	Weighted average interest rate	Weighted average time for which rate is fixed	Amount	Weighted average interest rate	Amount	Weighted average time until maturity	Am
	(%)	(Years)	($ million)	(%)	($ million)	(Years)	($ m
At December 31, 2001							
US dollar..............	7	8	11,624	2	10,143	4	1
Sterling...............	--	--	--	4	133	3	
Other currencies........	10	29	122	6	194	2	
			11,746		10,470		1
At December 31, 2000							
US dollar...........	7	9	10,506	6	10,674	4	2
Sterling...........	--	--	--	6	449	6	
Other currencies....	8	30	45	10	247	2	
			10,551		11,370		2

	December 31, 2001	December 31, 2000
	($ million)	($ million)
Analysis of the above liabilities by balance sheet caption:		
Current liabilities -- falling due within one year		
-- Finance debt..	9,090	6,418
Noncurrent liabilities		
-- Finance debt..	12,327	14,772
-- Accounts payable and accrued liabilities.....................	1,673	2,501
Provisions for liabilities and charges		
-- Other provisions...	1,102	1,064
	24,192	24,755

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 28 -- Derivative financial instruments (continued)

The financial liabilities upon which interest is paid comprise principally borrowings and net obligations under finance leases. The financial liabilities which are interest free comprise various accruals, sundry creditors and provisions relating to the Group's normal commercial operations with payment dates spread over a number of years.

In managing its finance debt, the Group aims for a balance between floating and fixed interest rates and, in 2001, the proportion of floating rate debt was in the range of 32-43% of total net debt outstanding. Interest rate swaps and futures are used by the Group to modify the interest characteristics of its long-term borrowings from a fixed to a floating rate basis or vice versa. The following table indicates the types of instruments used and their weighted average interest rates.

	December 31, 2001	December 31, 2000
	($ million except percentages)	
Receive fixed rate swaps -- notional amount...........	999	2,310
Average receive fixed rate	5.6%	6.4%
Average pay floating rate............................	2.3%	6.7%
Pay fixed rate swaps -- notional amount..............	2,914	3,125
Average pay fixed rate...............................	6.6%	6.7%
Average receive floating rate........................	2.3%	6.7%
Futures contracts -- notional amount.................	760	--
Average pay fixed rate...............................	2.7%	--

The following table shows the interest rate and currency profile of the Group's material financial assets.

	Fixed rate			Floating rate		Interest free	
	Weighted average interest rate	Weighted average time for which rate is fixed	Amount	Weighted average interest rate	Amount	Weighted average time until maturity	Am
	(%)	(Years)	($ million)	(%)	($ million)	(Years)	($ m
At December 31, 2001							
US dollar...........	3	1	92	2	574	2	2
Sterling............	7	2	81	4	11	2	
Other currencies....	5	1	181	5	264	1	

			354		849		3
At December 31, 2000								
US dollar...........	4	1	226	5	1,127	2	1
Sterling............	8	2	81	5	74	2	
Other currencies....	6	1	115	6	593	3	
			422		1,794		3

	December 31, 2001	December 31, 2000
	($ million)	
Analysis of the above financial assets by balance sheet caption:		
Fixed assets -- investments......................................	2,353	3,054
Current assets		
--Receivables -- amount falling due after more than one year......	265	578
--Investments..	450	661
--Cash at bank and in hand.......................................	1,358	1,170
	4,426	5,463

The floating rate financial assets earn interest at various rates set principally with respect to LIBOR or the local market equivalent.

Fixed asset investments included in the table above are held for the long term and have no maturity period. They are excluded from the calculation of weighted average time until maturity.

Note 28 -- Derivative financial instruments (continued)

Maturity profile of financial liabilities

The profile of the maturity of the financial liabilities included in the Group's balance sheet is shown in the table below.

	December 31, 2001	December 31, 2000
	($ million)	
Due within:1 year..................................	9,090	6,418

1 to 2 years	2,159	3,834
2 to 5 years	3,656	4,456
Thereafter	9,287	10,047
	24,192	24,755

Foreign exchange rate risk

The table below shows the Group's principal currency exposures arising from normal trading activities. These exposures give rise to net currency gains and losses recognized in the profit and loss account. Such exposures comprise the monetary assets and monetary liabilities of the Group that are not denominated in the functional currency of the operating unit involved. As at December 31, 2001 and 2000, these exposures were as shown below.

	Net foreign currency monetary assets (liabilities)				
	US dollar	Sterling	Euro	Other	Total
	($ million)				
At December 31, 2001					
US dollar	--	(193)	10	(15)	(198)
Sterling	69	--	237	182	488
Other	(487)	(241)	(3)	(27)	(758)
	(418)	(434)	244	140	(468)
At December 31, 2000					
US dollar	--	(555)	313	(534)	(776)
Sterling	487	--	498	269	1,254
Other	584	189	(9)	(231)	533
	1,071	(366)	802	(496)	1,011

Note 28 -- Derivative financial instruments (continued)

In accordance with its policy for managing its foreign exchange rate risk, the Group enters into various types of foreign exchange contracts, such as currency swaps, forwards and options. The fair values and carrying amounts of these derivatives are shown in the fair value disclosures below.

Fair values of financial assets and liabilities

The estimated fair value of the Group's financial instruments is shown in the table below. The table also shows the 'net carrying amount' of the financial asset or liability. This amount represents the net book value, i.e. market value when acquired or later marked to market. The carrying amounts and fair values of finance debt shown below exclude the effects of interest rate swaps, currency swaps and forward contracts (which are included for presentation in the balance sheet). Current maturities of long-term finance debt are included under long-term borrowings.

	December 31,		
	2001		
	Net fair value asset (liability)	Net carrying amount asset (liability)	Net fair v asset (liabi
		($ million)	
Primary financial instruments			
Fixed assets -- investments	2,350	2,353	2
Current assets			
-- Other receivables -- amounts falling due after more than one year	265	265	
-- Investments	459	450	
-- Cash at bank and in hand	1,358	1,358	1
Finance debt			
-- Short-term borrowings	(5,185)	(5,185)	(3
-- Long-term borrowings	(14,875)	(14,360)	(15
-- Net obligations under finance leases	(1,619)	(1,608)	(1
Noncurrent liabilities			
-- Accounts payable and accrued liabilities	(1,673)	(1,673)	(2
Provisions for liabilities and charges -- other provisions	(1,102)	(1,102)	(1
Derivative financial or commodity instruments			
Risk management -- interest rate contracts	(139)	--	
-- foreign exchange contracts	(251)	(264)	
-- oil price contracts	--	--	
-- natural gas price contracts	(259)	(259)	
Trading -- interest rate contracts	--	--	
-- foreign exchange contracts	(3)	(3)	
-- oil price contracts	26	26	
-- natural gas price contracts	12	12	

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 28 -- Derivative financial instruments (continued)

Interest rate contracts include futures contracts, swap agreements and options. Foreign exchange contracts include forward and futures contracts, swap agreements and options. Oil and natural gas price contracts are those which require settlement in cash and include futures contracts, swap agreements and options and cash-settled commodity instruments (derivative commodity contracts that permit settlement either by delivery of the underlying commodity or in cash) such as forward contracts.

The following methods and assumptions were used by the Group in estimating its fair value disclosures for its financial instruments:

Fixed assets -- Investments: The carrying amount reported in the balance sheet for unlisted fixed asset investments approximates their fair value. The fair value of listed fixed asset investments has been determined by reference to market prices.

Current assets -- Other receivables - amounts falling due after more than one year: The fair value of other receivables due after one year is estimated not to be materially different from its carrying value.

Current assets -- Investments and Cash at bank and in hand: The carrying amount reported in the balance sheet for unlisted current asset investments and cash at bank and in hand approximates their fair value. The fair value of listed current asset investments has been determined by reference to market prices.

Finance debt: The carrying amount of the Group's short-term borrowings, which mainly comprise commercial paper, bank loans and overdrafts, approximates their fair value. The fair value of the Group's long-term borrowings and finance lease obligations is estimated using quoted prices or, where these are not available, discounted cash flow analyses, based on the Group's current incremental borrowing rates for similar types and maturities of borrowing.

Noncurrent liabilities -- Accounts payable and accrued liabilities: These liabilities are predominantly interest-free. In view of the short maturities, the reported carrying amount is estimated to approximate the fair value.

Provisions for liabilities and charges - Other provisions: Where the liability will not be settled for a number of years the amount recognized is the present value of the estimated future expenditure. The carrying amount of provisions thus approximates the fair value.

Derivative financial or commodity instruments: The fair values of the Group's interest rate and foreign exchange contracts are based on pricing models which take into account relevant market data. The fair values of the Group's oil and natural gas price contracts (futures contracts, swap agreements, options and forward contracts) are based on market prices.

Risk management

Gains and losses on derivatives used for risk management purposes are deferred and recognized in earnings or as adjustments to carrying amounts, as appropriate, when the underlying debt matures or the hedged transaction occurs. When an anticipated transaction is no longer likely to occur or finance debt is terminated before maturity, any deferred gain or loss that has arisen on the related derivative is recognized in the income statement, together with any gain or loss on the terminated item. Where such derivatives used for hedging purposes are terminated before the underlying debt matures or the hedged transaction occurs, the resulting gain or loss is recognized on a basis which matches the timing and accounting treatment of the underlying hedged item. The unrecognized and carried-forward gains and losses on derivatives used for hedging, and the movements therein, are shown in the following table.

Note 28 -- Derivative financial instruments (continued)

	Unrecognized			Carried forward i	
	Gains	Losses	Total	Gains	Los
	($ million)				
Gains and losses at January 1, 2001	303	(302)	1	56	(
of which accounted for in income in 2001	203	(154)	49	22	(
Gains and losses at December 31, 2001	109	(235)	(126)	113	(
of which expected to be recognized in income in 2002	60	(19)	41	50	(
Gains and losses at January 1, 2000	236	(215)	21	65	(
of which accounted for in income in 2000	54	(60)	(6)	32	

Trading activities

The Group maintains active trading positions in a variety of derivatives. This activity is undertaken in conjunction with risk management activities. Derivatives held for trading purposes are marked to market and any gain or loss recognized in the income statement. For traded derivatives, many positions have been neutralized, with trading initiatives being concluded by taking opposite positions to fix a gain or loss, thereby achieving a zero net market risk.

The following table shows the fair value at December 31, 2001 of derivatives and other financial instruments held for trading purposes. The fair values at the year end are not materially unrepresentative of the position throughout the year.

	Years ended December 31,			
	2001		2000	
	Year end fair value asset	Year end fair value liability	Year end fair value asset	Year en fair valu liabilit
	($ million)			
Interest rate contracts	--	--	--	--
Foreign exchange contracts	14	(17)	10	(10
Oil price contracts	248	(222)	159	(123
Natural gas price contracts	799	(787)	1,288	(1,264
	1,061	(1,026)	1,457	(1,397

The Group measures its market risk exposure, i.e. potential gain or loss in fair values, on its trading activity using value-at-risk techniques. These techniques are based on a variance/covariance model or a Monte Carlo simulation and make a statistical assessment of the market risk arising from possible future changes in market values over a 24-hour period. The calculation of the range of potential changes in fair value takes into account a snapshot of the end-of-day exposures, and the history of one-day price movements over the previous 12 months, together with the correlation of these price movements. The potential movement in fair values is expressed to three standard deviations which is equivalent to a 99.7% confidence level. This means that, in broad terms, one would expect to see an increase or a decrease in fair values greater than the value at risk on only one occasion per year if the portfolio were left unchanged.

Note 28 -- Derivative financial instruments (continued)

The Group calculates value at risk on all instruments that are held for trading purposes and that therefore give an exposure to market risk. The value-at-risk model takes account of derivative financial instruments such as interest rate forward and futures contracts, swap agreements, options and swaptions, foreign exchange forward and futures contracts, swap agreements and options and oil price futures, swap agreements and options. Financial assets and liabilities and physical crude oil and refined products that are treated as trading positions are also included in these calculations. The value-at-risk calculation for oil and natural gas price exposure also includes derivative commodity instruments (commodity contracts that permit settlement either by delivery of the underlying commodity or in cash) such as forward contracts.

The following table shows values at risk for trading activities.

	Years ended December 31,					
	2001					
	High	Low	Average	Year end	High	Lo
				($ million)		
Interest rate trading...........	1	--	--	--	2	-
Foreign exchange trading........	3	--	1	--	15	-
Oil price trading...............	29	10	18	17	23	
Natural gas price trading.......	21	4	10	9	16	

The presentation of trading results shown in the table below includes certain activities of BP's trading units which involve the use of derivative financial instruments in conjunction with physical and paper trading of oil and natural gas. It is considered that a more comprehensive representation of the Group's oil and natural gas price trading activities is given by the classification of the gain or loss on such derivatives along with the gain or loss arising from the physical and paper trades to which they relate, representing the net result of the trading portfolio.

Year ended December 31,

	2001			2000
	Oil	Natural gas	Net gain (loss)	Net gain (loss)
	($ million)			
Derivative financial and commodity instruments...	419	(129)	290	94
Physical trades................................	265	405	670	549
Total trading............................	684	276	960	643
Interest rate trading....................			1	1
Foreign exchange trading.................			81	52
			1,042	696

The following information is presented in compliance with the requirements of FASB Statement of Accounting Standards No. 105 -- 'Disclosure of Information about Financial Instruments with Off-Balance-Sheet Risk and Financial Instruments with Concentrations of Credit Risk', No. 107 -- 'Disclosure about Fair Value of Financial Instruments', No. 119 -- 'Disclosures about Derivative Financial Instruments and Fair Value of Financial Instruments' and No. 133 -- 'Accounting for Derivative Instruments and Hedging Activities'.

The Group's accounting policies under UK GAAP do not satisfy the criteria for hedge accounting under SFAS 133. The Group does not intend to modify its practice under UK GAAP. See Note 43 - US generally accepted accounting principles.

Note 28 -- Derivative financial instruments (continued)

Further information on accounting policies

The following information is presented in amplification of the accounting policies presented in Note 1 -- Accounting policies.

Reporting in the income statement

Gains and losses on oil price contracts held for trading and for risk management purposes and natural gas price contracts held for trading purposes are reported in cost of sales in the income statement in the period in which the change in value occurs. Gains and losses on interest rate or foreign currency derivatives used for trading are reported in other income and cost of sales, respectively. Gains and losses in respect of derivatives used to manage interest rate exposures are recognized as adjustments to interest expense.

Where derivatives are used to convert non-US dollar borrowing into US dollars, the gains and losses are deferred and recognized on maturity of the underlying debt, together with the matching loss or gain on the debt. The two amounts offset each other in the income statement.

Gains and losses on derivatives identified as hedges of significant non-US dollar firm commitments or anticipated transactions are not recognized until the hedged transaction occurs. The treatment of the gain or loss arising on the designated derivative reflects the nature and accounting treatment of the hedged item. The gain or loss is recorded in cost of sales in the income statement or as an adjustment to carrying values in the balance sheet, as appropriate.

Gains and losses arising from natural gas price derivatives are recognized in earnings when the hedged transaction occurs. The gains or losses are reported as components of the related transactions.

Reporting in the balance sheet

The carrying amounts of foreign exchange contracts that hedge finance debt are included within finance debt in the balance sheet. The carrying amounts of other derivatives, including option premiums paid or received, are included in the balance sheet under receivables or payables within current assets and current liabilities respectively, as appropriate.

Cash flow effects

Interest rate swaps give rise, at specified intervals, to cash settlement of interest differentials. Under currency swaps the counterparties initially exchange a principal amount in two currencies, agreeing to re-exchange the currencies at a future date at the same exchange rate. The Group's currency swaps have terms of up to eight years.

Interest rate futures require an initial margin payment and daily settlement of margin calls. Interest rate forwards require settlement of the interest rate differential on a specified future date. Currency forwards require purchase or sale of an agreed amount of foreign currency at a specified exchange rate at a specified future date, generally over periods of up to one year for the Group. Currency options involve the initial payment or receipt of a premium and will give rise to delivery of an agreed amount of currency at a specified future date if the option is exercised.

Note 28 -- Derivative financial instruments (continued)

For oil and natural gas price futures and options traded on regulated exchanges, BP meets initial margin requirements by bank guarantees and daily margin calls in cash. For swaps and over-the-counter options, BP settles with the counterparty on conclusion of the pricing period.

In the statement of cash flows the effect of interest rate derivatives is reflected in interest paid. The effect of foreign currency derivatives used for hedging non-US dollar debt is included under financing. The cash flow effects of foreign currency derivatives used to hedge non-US dollar firm commitments and anticipated transactions are included in net cash inflow from operating activities for items relating to earnings or in capital expenditure or acquisitions, as appropriate, for items of a capital nature. The cash flow effects of all oil and natural gas price derivatives and all traded derivatives are included in net cash inflow from operating activities.

Fair value of financial instruments

The carrying amounts and fair values of finance debt are as follows:

	December 31, 2001 Carrying amount asset (liability)	2001 Fair value asset (liability)	2000 Carrying amount asset (liability)	2000 Fair value asset (liability)
	($ million)			
Finance debt				
Long-term	(14,360)	(14,875)	(15,299)	(15,573)
Short-term	(5,185)	(5,185)	(3,706)	(3,706)
Cash at bank and in hand	1,358	1,358	1,170	1,170

The carrying amounts of foreign exchange contracts that hedge finance debt are included within finance debt in the balance sheet. The carrying amounts of other derivatives are included in the balance sheet under receivables or payables as appropriate.

In addition to the above financial instruments, the Group has issued third party guarantees and indemnities amounting to $275 million ($454 million at December 31, 2000). The credit risk and maximum cash requirement of these guarantees and indemnities is the full contractual amount, however no material loss is expected to arise.

Note 28 -- Derivative financial instruments (continued)

The table shows the 'fair value' of the asset or liability created by derivatives. This represents the market value at the balance sheet date. Credit exposure at December 31 is represented by the column 'fair value asset'.

The table also shows the 'net carrying amount' of the asset or liability created by derivatives. This amount represents the net book value. While the gross contract or notional amounts give an indication of the scale of business transacted, they do not represent the Group's aggregate exposure to market or credit risk.

	Gross contract amount	Fair value asset	Fair value liability	Net carrying amount asset (liability)
	($ million)			
At December 31, 2001				
Risk management				
Interest rate contracts	4,673	18	(157)	--

Foreign exchange contracts.....	9,628	80	(331)	(264)
Oil price contracts...........	230	3	(3)	--
Natural gas price contracts....	4,619	91	(350)	(259)
Trading				
Interest rate contracts........	791	--	--	--
Foreign exchange contracts.....	2,283	14	(17)	(3)
Oil price contracts...........	33,076	248	(222)	26
Natural gas price contracts....	48,774	799	(787)	12
At December 31, 2000				
Risk management				
Interest rate contracts........	5,435	54	(103)	--
Foreign exchange contracts.....	8,132	114	(452)	(369)
Oil price contracts...........	434	19	(15)	4
Natural gas price contracts....	2,614	147	(116)	12
Trading				
Interest rate contracts........	--	--	--	--
Foreign exchange contracts.....	2,434	10	(10)	--
Oil price contracts...........	6,316	159	(123)	36
Natural gas price contracts....	36,206	1,288	(1,264)	24

Interest rate contracts include futures contracts, swap agreements and options. Foreign exchange contracts include forward and futures contracts, swap agreements and options. Oil and natural gas price contracts are those which require settlement in cash and include futures contracts, swap agreements and options.

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 28 -- Derivative financial instruments (continued)

Interest rate risk management

The Group enters into interest rate contracts to manage its cost of borrowing as indicated in the following table:

	December 31, 2001			December 31, 2000		
	Gross contract amount	Fair value asset	Fair value liability	Gross contract amount	Fair value asset	Fair value liability
	($ million)					
Swaps	3,913	18	(157)	5,435	54	(103)
Futures.....................	760	--	--	--	--	--
	4,673	18	(157)	5,435	54	(103)

Interest rate swaps allow BP to modify the interest characteristics of its long-term borrowings from a fixed to a floating rate basis or vice versa. Under interest rate swaps, the Group agrees with other parties to exchange, at specified intervals, the interest differentials calculated by reference to an agreed notional principal amount. There is no exchange of the underlying principal amount.

Interest rate futures contracts are used by the Group, on occasion, in preference to interest rate swaps to achieve a more cost effective method of managing the mix between fixed and floating rate debt. These contracts are commitments to either purchase or sell designated financial instruments at a future date for a specified price, and may be settled in cash or through delivery. The Group may hold highly liquid contracts, such as US Treasury bond futures and Eurodollar futures, with terms ranging up to two years. Initial margin requirements and daily calls are met either by the deposit of securities or in cash. Futures contracts have little credit risk as regulated exchanges are the counterparties.

The following table indicates the types of instruments used and their weighted average interest rates. Average variable rates are based on the actual rates in place at December 31; these may change significantly, affecting future cash flows. Swap contracts mainly have maturities between one and ten years.

	December 31,	
	2001	2000
	($ million, except percentages)	
Receive -- fixed swaps -- notional amount..........	999	2,310
Average receive fixed rate........................	5.6%	6.4%
Average pay floating rate.........................	2.3%	6.7%
Pay -- fixed swaps -- notional amount.............	2,914	3,125
Average pay fixed rate............................	6.6%	6.7%
Average receive floating rate.....................	2.3%	6.7%
Futures contracts -- notional amount..............	760	--
Average pay fixed rate............................	2.7%	--

Interest rate forward contracts, which include forward rate agreements and options on forward rate agreements, may also be used by the Group to manage interest rate risk on debt. These contracts are agreements which allow the interest rate cost on a principal amount to be fixed for a specified period commencing on a future date.

Note 28 -- Derivative financial instruments (continued)

Swaptions may also be employed to manage interest rate risk on debt. A swaption is an agreement that conveys the right, but not the obligation, to swap a series of fixed rate interest payments for floating rate interest payments, or vice versa, at a given future point in time. Typically the swaptions entered into by the Group are cash settled at expiry.

Foreign exchange risk management

The Group enters into various types of foreign exchange contracts in managing its foreign exchange risk as indicated in the following table:

	December 31, 2001			December 31, 2000		
	Gross contract amount	Fair value asset	Fair value liability	Gross contract amount	Fair value asset	Fair value liability
	($ million)					
Currency swaps...............	1,789	12	(247)	2,441	15	(303)
Forwards.....................	7,839	68	(84)	5,691	99	(149)
Options......................	--	--	--	--	--	--
	9,628	80	(331)	8,132	114	(452)

The Group's foreign exchange management policy is to minimize economic exposures from currency movements against the US dollar. This is achieved by raising finance in US dollars, hedging with respect to the US dollar or swapping into US dollars and hedging significant non-dollar cash flows. Examples of significant non-dollar cash flows are sterling-based capital lease payments, sterling tax payments, sterling dividend payments and capital expenditure and operational requirements of Exploration in the UK.

Under currency swaps the counterparties initially exchange a principal amount in two currencies, agreeing to re-exchange the currencies at a future date and at the same exchange rate. In addition, interest payments in the respective currencies are exchanged at specified intervals over the term of the agreement. The Group's currency swaps have terms up to eight years. The majority of the Group's currency swaps relate to major currencies such as Sterling, Euros, Swiss Francs, Canadian Dollars and Japanese Yen.

Currency forward contracts are commitments to purchase or sell an agreed amount of foreign currency at a specified exchange rate at a specified future date.

Currency options may be used from time to time. They are normally directly negotiated and allow, but do not require, the holder to buy from or sell to the writer an agreed amount of currency at a specified exchange rate within a stated period, and involve the initial payment or receipt of a premium. The Group's option contracts have an average term of less than one year. There were no option contracts outstanding at December 31, 2001 and 2000.

Currency options may include cylinder option contracts. A cylinder is the purchase of an option to buy foreign currency and the simultaneous selling of an option to sell the same amount of foreign currency to BP at a different exchange rate. The effect is to limit the risk of both gain and loss. This is achieved at little or no cost as the symmetry of the options means that the premium paid for one option is balanced by the premium received from the sale of the other.

Note 28 -- Derivative financial instruments (continued)

Oil and natural gas price risk management

The Group enters into various types of oil and natural gas price contracts to manage its exposure to some movements in hydrocarbon prices as indicated in the following table. Contracts which are capable of being settled by delivery of oil, oil products or natural gas are excluded.

	December 31, 2001			December 31, 2000		
	Gross contract amount	Fair value asset	Fair value liability	Gross contract amount	Fair value asset	Fair value liability
	($ million)					
Oil						
Swaps.................	123	2	(3)	239	13	(13)
Options...............	4	1	--	6	1	(1)
Futures...............	103	--	--	189	5	(1)
	230	3	(3)	434	19	(15)
Natural gas						
Swaps.................	3,494	85	(339)	2,511	133	(114)
Options...............	1,090	6	(11)	7	10	(2)
Futures...............	35	--	--	96	4	--
	4,619	91	(350)	2,614	147	(116)

The Group uses swaps, options and futures to hedge future purchases and sales of crude oil and refined oil products. The term of the oil price derivatives is usually less than one year. Natural gas swaps, options and futures are used to convert specific sales and purchase contracts from fixed prices to market prices. Swaps are also used to hedge exposure for price differentials between locations. The term of most natural gas price derivatives is less than one year, with some having terms of two years.

Under swaps, BP agrees with other parties to pay or receive the difference between a fixed and variable price at a range of specified dates determined by reference to an agreed notional volume.

The option and futures contracts are traded on regulated exchanges. Exchange-traded options allow, but do not require, the holder to either buy from or sell to the writer an agreed amount of futures contracts at a specified price at a specified future date. Futures are fixed price commitments to purchase or sell a contract, whose value is derived from the price of oil at a specified future date. Initial margin requirements and daily cash settlements for both these types of contracts are met either by bank guarantees or in cash. There is little credit risk under these contracts as regulated exchanges are the counterparties.

Trading activities

The Group maintains active trading positions in a variety of derivatives.

This activity is undertaken in conjunction with risk management. Derivatives held for trading purposes are marked to market and any gain or loss recognized in the income statement. For traded derivatives, many positions have been neutralized, with trading initiatives being concluded by taking opposite positions to fix a gain or loss, thereby achieving a zero net market risk.

F - 48

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 28 -- Derivative financial instruments (concluded)

The following table discloses the contract or notional amount and fair value of the derivatives held for trading purposes at December 31, 2001 and 2000 and the average fair value for the year.

	Year ended December 31, 2001			Year ended December 31, 2000		
	Gross contract amount	Net fair value asset (liability)	Average fair value asset (liability)	Gross contract amount	Net fair value asset (liability)	Average fair value asset (liability)
	($ million)					
Interest rate contracts						
Futures	791	--	--	--	--	--
Options	--	--	--	--	--	--
Swaptions	--	--	--	--	--	--
	791	--	--	--	--	--
Foreign exchange contracts						
Forwards	2,037	(3)	(4)	2,388	(1)	(3)
Options	246	--	--	46	1	--
	2,283	(3)	(4)	2,434	--	(3)
Oil price contracts						
Swaps	5,560	20	27	3,549	35	1
Futures	911	--	--	1,985	--	--
Options	26,605	6	7	782	1	3
	33,076	26	34	6,316	36	4
Natural gas price contracts						
Swaps	15,454	(15)	23	36,129	40	19
Futures	150	--	--	--	(12)	(4)
Options	33,170	27	26	77	(4)	--
	48,774	12	49	36,206	24	15

Concentrations of credit risk

The primary activities of the Group are oil and natural gas exploration and production, gas and power marketing and trading, oil refining and marketing and the manufacture and marketing of chemicals. The Group's principal customers, suppliers and financial institutions with which it conducts business are located throughout the world. The credit ratings of interest rate and currency swap counterparties are all of at least investment grade. The credit quality is actively managed over the life of the swap.

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 29 -- Capital and reserves

	Share capital	Paid in surplus	Merger reserve	Other reserves	Retained earnings	Tot
			($ million)			
At January 1, 2001	5,653	3,770	26,869	456	36,668	73,4
Exchange adjustment	--	--	--	--	(908)	(9
Employee share schemes	8	118	--	--	--	1
ARCO	7	51	114	(117)	--	
Redemption of ARCO preference shares	--	--	--	(116)	--	(1
Share buyback	(39)	39	--	--	(1,281)	(1,2
Qualifying Employee Share Ownership Trust (QUEST)	--	36	--	--	(36)	
Profit for the year	--	--	--	--	8,010	8,0
Dividends	--	--	--	--	(4,935)	(4,9
At December 31, 2001	5,629	4,014	26,983	223	37,518	74,3

The movements in the Group's share capital during the year are set out above. All movements are quantified in terms of the number of BP shares issued or repurchased.

Employee share schemes. During the year 33,460,856 ordinary shares were issued under the BP, Amoco and Burmah Castrol employee share schemes.

ARCO. 10,728,978 ordinary shares were issued in connection with the conversion of ARCO preference shares and a further 13,069,008 ordinary shares were issued in respect of ARCO employee share option schemes.

Redemption of ARCO preference shares. A cash tender offer was made in March 2001 for the outstanding ARCO preference shares.

Share buyback. The Company purchased for cancellation 153,928,949 ordinary shares for a total consideration of $1,281 million.

Note 30 -- Retained earnings

Retained earnings of $37,518 million ($36,668 million at December 31, 2000) include the following amounts, the distribution of which is limited by statutory or other restrictions:

	December 31, 2001	December 31, 2000
	($ million)	
Parent company	15,547	17,547
Subsidiary undertakings	8,994	9,120
Joint ventures and associated undertakings	1,345	1,042
	25,886	27,709

Cumulative net exchange losses of $4,790 million are included in retained earnings ($3,882 million losses at December 31, 2000).

There were no unrealized currency translation differences for the year on long-term borrowings used to finance equity investments in foreign currencies (2000 nil and 1999 nil).

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 31 -- Analysis of consolidated statement of cash flows

(i) Reconciliation of historical cost profit before interest and tax to net cash inflow from operating activities

	Years ended December 31, 2001	2000	1999
	($ million)		
Historical cost profit before interest and tax	14,770	18,704	8,342
Depreciation and amounts provided	8,750	7,449	4,965
Exploration expenditure written off	238	264	304
Share of profits of joint ventures and associated undertakings	(1,194)	(1,853)	(1,704)
Interest and other income	(478)	(360)	(217)
(Profit) loss on sale of fixed assets and businesses or termination of operations	(537)	(196)	379
Charge for provisions	1,008	702	847
Utilization of provisions	(1,119)	(969)	(597)
Decrease (increase) in inventories	1,490	(1,449)	(1,562)
Decrease (increase) in debtors	1,989	(5,587)	(4,013)
(Decrease) increase in payables	(2,508)	3,711	3,546
Net cash inflow from operating activities	22,409	20,416	10,290

(ii) Exceptional items

The cash outflow in 2000 in respect of the restructuring costs charged in 1999 was $446 million (1999 $976 million). The cash outflow in 1999 relating to the merger expenses charged in 1998 was $166 million. Both amounts were included in the net cash inflow from operating activities.

(iii) Financing

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Long-term borrowing	(1,296)	(1,680)	(2,140)
Repayments of long-term borrowing	2,602	2,353	2,268
Short-term borrowing	(6,257)	(4,120)	(3,136)
Repayments of short-term borrowing	4,823	4,821	2,299
	(128)	1,374	(709)
Issue of ordinary share capital	(181)	(257)	(245)
Share buyback	1,281	2,001	--
Stamp duty reserve tax	--	295	--
Net cash outflow (inflow)	972	3,413	(954)

(iv) Management of liquid resources

Liquid resources comprise current asset investments which are principally commercial paper issued by other companies. The net cash inflow from the management of liquid resources was $211 million (2000 $452 million outflow and 1999 $93 million inflow).

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 31 -- Analysis of consolidated statement of cash flows (concluded)

(v) Commercial paper

Net movements in commercial paper are included within short-term borrowings or repayment of short-term borrowings as appropriate.

(vi) Movement in net debt

Years ended December 31,						
2001				2000		
Finance debt	Cash	Current asset investments	Net debt	Finance debt	Cash	in

			($ million)			
At January 1..........	(21,190)	1,170	661	(19,359)	(14,544)	1,331
Exchange adjustments..	(8)	(53)	--	(61)	96	(39)
Acquisitions..........	(55)	--	--	(55)	(8,072)	--
Net cash flow.........	(128)	241	(211)	(98)	1,374	(122)
Other movements.......	(36)	--	--	(36)	(44)	--
At December 31........	(21,417)	1,358	450	(19,609)	(21,190)	1,170

Note 32 -- Operating lease commitments

Annual commitments under operating leases were as follows:

	December 31, 2001		December 31, 2000	
	Land and buildings	Other	Land and buildings	Other
	($ million)			
Expiring within: 1 year..................	28	313	41	181
2 to 5 years............	115	306	54	330
Thereafter..............	184	113	235	220
	327	732	330	731

The minimum future lease payments (after deducting related rental income from operating sub-leases of $580 million) were as follows:

	December 31, 2001
	($ million)
2002	958
2003	729
2004	573
2005	515
2006	465
Thereafter........	2,626
	5,866

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 33 -- Employee share schemes

BP offers most of its employees the opportunity to acquire a shareholding in the company through savings-related and matching share plan arrangements. Such arrangements are now in place in over 60 countries. BP also uses long-term performance plans (see Note 34) and the granting of share options as elements of remuneration for executive directors and senior employees.

During 2001 share options were granted to the executive directors under the Executive Directors' Long Term Incentive Plan (EDLTIP) and to certain other categories of employees. For these options the option price was the market price on the grant date. The options granted to executive directors reflect BP's performance in terms of total shareholder return (TSR), that is, share price increase with all dividends reinvested, relative to the FTSE global 100 group of companies over the three years preceding the grant. The options are exercisable between the third and the tenth anniversary of the date of grant.

Share options were also granted in 2001 under the BP Share Option Plan to certain categories of employees. Subject to certain vesting requirements the options are exercisable between the third and tenth anniversaries of the date of grant. There are no performance conditions attaching to the options granted during the year.

Under the BP ShareSave Plan (a savings-related share option scheme) employees save monthly over a three- or five-year period towards the purchase of shares at a price fixed when the option is granted. The option price is usually set at a 20% discount to the market price at the time of grant. The option must be exercised within six months of maturity of the savings contract; otherwise it lapses. The plan is run in the UK and a small number of other countries.

For the BP ShareMatch Plan, BP matches employees' own contributions of shares, up to a predetermined limit. The shares are then held in trust for a defined minimum period. The plan is run in the UK and in over 40 other countries.

The Company sponsors a number of savings plans covering most US employees. Under these plans, employees may contribute up to 18% of their salary subject to certain regulatory limits. Typically the employee receives a dollar-for-dollar company matched contribution for the first 7% of eligible pay contributed to most of these plans on a before-tax or after-tax basis, or a combination of both. The precise arrangement depends on the individual's employment contract. Company contributions are initially invested in BP ADS funds, but employees may transfer those amounts and may invest their own contributions in more than 200 investment options. The Company's contributions vest over a period of five years. Company contributions to savings plans during the year were $125 million ($101 million).

An employee Share Ownership Plan (ESOP) was established in 1997 to acquire BP shares to satisfy future requirements of certain employee share plans. The Company provides funding to the ESOP. The assets and liabilities of the ESOP are recognized as assets and liabilities of the Company within the accounts. The ESOP has waived its rights to dividends.

During 2001 the ESOP released 11,508,754 shares (2000, 9,412,931 shares) for the matching share plans. The cost of shares released for these plans has been charged in these accounts. At December 31, 2001 the ESOP held 34,005,910 shares (2000, 45,514,664 shares).

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 33 -- Employee share schemes (continued)

BP has established a Qualifying Employee Share Ownership Trust (QUEST) to support the UK ShareSave plan. During the year, contributions of $36 million ($76 million) were made by the Company to the QUEST which, together with option-holder contributions, were used by the QUEST to subscribe for new ordinary shares at market price. The Company has transferred the cost of this contribution directly to retained profits and the excess of the subscription price over nominal value has increased the share premium account.

At December 31, 2001, all the 8,148,640 ordinary shares issued to the QUEST had been transferred to employees exercising options under the UK ShareSave plan.

	Years ended December 31,		
	2001	2000	1999
	(options thousands)		
Employee share options granted during the year:			
Savings related schemes	7,901	7,930	8,828
BP Share Option Plan	58,208	50,461	41,054
	66,109	58,391	49,882

The exercise prices for BP options granted during the year were (pound)5.11/$7.36 (7,900,810 options) for savings-related and similar schemes and (pound)5.72/$8.23 (weighted average price) for 58,207,741 options granted under the share option plan.

	Years ended December 31,		
	2001	2000	1999
	(shares thousands)		
Shares issued in respect of options exercised during the year:			
Savings related schemes	8,842	13,709	12,176
BP, Amoco and Burmah Castrol executive share option plans	24,619	23,280	51,472
	33,461	36,989	63,648

In 2001 11,508,754 shares (2000, 9,412,931 shares and 1999, 8,779,000 shares) were released from the ESOP for matching share plans. In 2000, 1,123,000 shares and 1999, 2,514,000 shares were issued to the ESOP.

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 33 -- Employee share schemes (continued)

	2001	2000	
		(shares thousands)	
Options outstanding at December 31:			
BP options	370,550	342,509	323
Exercise period	2002-2011	2001-2010	2000-
Price (pound)	1.29-6.40	1.29-6.40	1.29-
Price (dollar)	2.77-9.97	2.77-9.97	2.77-

Share option transactions under employee share schemes are summarized as follows:

	Years ended December 31,					
	2001		2000		1999	
	Number of shares	Weighted average exercise price	Number of shares	Weighted average exercise price	Number of shares	Wei av exe
		($)		($)		
Outstanding at January 1	342,509,046	5.61	323,161,387	4.95	346,897,822	
Burmah Castrol	--	--	3,293,317	5.02	--	
Reinstated	7,152	7.84	3,729	2.94	37,480	
Granted	66,108,551	8.13	58,390,883	8.17	49,882,128	
Exercised	(33,592,964)	3.97	(37,029,467)	3.76	(63,711,433)	
Stock appreciation rights exercised	--	--	--	--	(542,772)	
Cancelled	(4,481,516)	7.37	(5,310,803)	6.72	(9,401,838)	
Outstanding at December 31	370,550,269	6.18	342,509,046	5.61	323,161,387	
Exercisable at December 31	241,268,277		229,987,199		206,116,577	
Available for grant at December 31	1,185,523,186		1,234,983,212		1,087,626,398	

Options outstanding at December 31, 2001 will be exercisable between 2002 and 2011.

Note 33 -- Employee share schemes (concluded)

For the share options outstanding and exercisable at December 31, 2001 the exercise price ranges and average remaining lives were:

	Options outstanding			Options exercisable	
	Number of shares	Weighted average remaining life (years)	Weighted average exercise price ($)	Number of shares	Weighted average exercise price ($)
Range of exercise prices					
$2.27 - $4.46.................	77,538,865	2.11	3.55	77,126,053	3.54
$4.51 - $5.49.................	82,106,458	5.01	5.10	72,961,042	5.15
$5.54 - $7.98.................	114,558,374	5.69	6.93	71,427,330	6.67
$8.02 - $9.97.................	96,346,572	8.76	8.33	19,753,852	8.29
	370,550,269	5.59	6.18	241,268,277	5.34

As allowed by SFAS 123 `Accounting for Stock-Based Compensation' the Company has elected to continue to follow Accounting Principles Board Opinion No. 25, 'Accounting for Stock Issued to Employees'. In accordance with this accounting statement the Company does not recognize compensation expense on the grant of the options. Had compensation expense been determined based upon the fair value of the stock options at grant date consistent with the method of SFAS 123, the Company's profit for the year and profit per ordinary share for 2001 would have been reduced by $126 million (2000 $122 million and 1999 $65 million) and 1 cent (2000 1 cent and 1999 1 cent), respectively.

The weighted average fair value of BP share options granted in 2001 was $2.05 (2000 $2.33 and 1999 $2.27). The fair value of each option grant was estimated on the date of grant using a Black-Scholes option pricing model with the following assumptions for 2001, 2000 and 1999, respectively; risk-free interest rates of 5.0%, 6.0% and 6.5%; dividend yield of 3%; expected lives of one, two, three or five years as appropriate and volatility of 26%, 33% and 32%.

Note 34 -- Long Term Performance Plan

During 2001 the Company operated two long-term performance plans: the Executive Directors' Long Term Incentive Plan (EDLTIP) for executive directors and the Long Term Performance Plan (LTPP) for senior executives. Prior to 2000 the executive directors also participated in the LTPP. Both plans are incentive schemes under which the Company may award shares to participants or fund the purchase of shares for participants if long-term targets are met. Awards were made in 2001 in respect of the 1998-2000 LTPP.

The cost of potential future awards for both the EDLTIP and LTPP are accrued over the three-year performance periods of each plan. The amount charged in 2001 was $80 million (2000 $119 million). The value of awards under the 1998-2000 LTPP made in 2001 was $61 million (1997-99 LTPP $78 million).

Employee Share Ownership Plans (ESOPs) have been established to acquire BP shares to satisfy any awards made to participants under the EDLTIP and LTPP and then to hold them for the participants during the retention period of the plan. In order to hedge the cost of potential future awards the ESOPs may, from time to time over the performance period of the plans, purchase BP shares in the open market. The Company provides funding to the ESOPs. The assets and liabilities of the ESOPs are recognized as assets and liabilities of the Company within these accounts. The ESOPs have waived their rights to dividends on shares held for future awards.

At December 31, 2001 the ESOPs held 7,673,056 shares (2000, 9,506,839 shares) for potential future awards.

Note 35 -- Directors' remuneration

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Total for all directors			
Emoluments	17	14	13
Ex gratia payment	--	1	6
Non-executive directors retiring in 2001	1	--	--
Gains made on the exercise of share options	--	3	5
Amounts awarded under long-term incentive schemes	17	15	8
Highest paid director			
Emoluments	4	3	2
Gains made on the exercise of share options	--	--	5
Amount awarded under long-term incentive schemes	4	4	--
Accrued pension at December 31	1	1	1

Emoluments

These amounts comprise fees paid to the non-executive chairman and non-executive directors, and, for executive directors, salary and benefits earned during the relevant financial year, plus bonuses awarded for the year.

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 35 -- Directors' remuneration (continued)

Pension contributions

Five executive directors participate in a non-contributory pension scheme established for UK staff by a separate trust fund to which contributions are made by BP based on actuarial advice. There were no contributions to this pension scheme in 2001, 2000 and 1999. Two US executive directors participated in the BP Retirement Accumulation Plan.

Non-executive directors retiring in 2001

In accordance with Article 76 of the Company's Articles of Association, the board exercised its discretion, following the retirement of each of those non-executive directors retiring during 2001, to make an ex gratia payment in lieu of superannuation. The payments made were as follows: $86,400 to the Lord Wright of Richmond, who retired after serving on the board since 1991; $21,600 to Richard Ferris, who retired after serving on the board of first Amoco and then BP since 1981; and $17,280 to Ruth Block, who retired after serving on the board of first Amoco and then BP since 1986. Richard Ferris and Ruth Block also had accrued certain entitlements (which crystallized at the time of the merger with Amoco Corporation) in the Amoco Restricted Stock Plan for Non-Executive Directors ('the Plan'). The terms of the Plan provided that shares in respect of service on the board of Amoco Corporation were to be held in the Plan until the non-executive director retired at the normal retirement age (70), or in the case of earlier retirement the board had a discretion to make an appropriate award based upon length of service. Those directors who left the Plan at the time of the merger had their entitlements paid out. The operation of the Plan for those who remained fell to the discretion of the board of BP. Ruth Block retired at age 70 and following her retirement the board released her shares held in the Plan in respect of her service at Amoco Corporation to the value of $283,512 (as at the date of their release). Richard Ferris retired at age 64 and the board elected to waive restrictions on all those shares held in the Plan in respect of his service at Amoco Corporation to the value of $293,716 (as at the date of their release).

Office facilities for former chairmen and deputy chairmen

It is customary for the Company to make available to former chairmen and deputy chairmen the use of office and basic secretarial facilities following their retirement. The cost involved in doing so is not significant.

Note 36 -- Loans to officers

Miss J C Hanratty has a low interest loan of $43,000 made to her prior to her appointment as Company Secretary on October 1, 1994.

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 37 -- Employee costs and numbers

	Years ended December 31, 2001	2000	1999
	($ million)		
Employee costs			
Wages and salaries..................................	6,740	6,071	5,302
Social security costs...............................	474	410	359
Pension costs.......................................	427	187	(97)
	7,641	6,668	5,564

	At December 31, 2001	2000	1999
Number of employees			
Exploration and Production..........................	16,550	16,000	12,500
Gas and Power.......................................	1,950	1,600	1,400
Refining and Marketing (a)..........................	64,600	67,100	44,650
Chemicals...	21,950	17,600	18,700
Other businesses and corporate......................	5,100	4,900	3,150
	110,150	107,200	80,400

	UK	Rest of Europe	USA	Rest of World	Total
Average number of employees					
Year ended December 31, 2001					
Exploration and Production.............	3,550	750	5,700	6,200	16,200
Gas and Power..........................	550	100	600	550	1,800
Refining and Marketing	10,400	16,450	27,300	11,750	65,900
Chemicals..............................	3,600	5,750	7,550	3,300	20,200
Other businesses and corporate.........	1,400	500	2,250	900	5,050
	19,500	23,550	43,400	22,700	109,150
Year ended December 31, 2000					
Exploration and Production.............	3,250	650	4,700	5,700	14,300
Gas and Power..........................	550	50	600	300	1,500
Refining and Marketing	9,600	13,700	25,800	10,700	59,800
Chemicals..............................	3,700	4,600	8,100	1,400	17,800
Other businesses and corporate.........	1,100	400	2,400	700	4,600
	18,200	19,400	41,600	18,800	98,000
Year ended December 31, 1999					
Exploration and Production.............	3,500	850	5,100	5,500	14,950
Gas and Power..........................	450	50	600	300	1,400
Refining and Marketing (b).............	9,600	10,050	20,300	7,950	47,900

Chemicals	4,100	4,900	9,850	2,000	20,850
Other businesses and corporate	1,150	350	1,000	500	3,000
	18,800	16,200	36,850	16,250	88,100

(a) 1999 includes 18,050 employees assigned to the BP/Mobil joint venture.

(b) Includes 7,800 employees assigned to the BP/Mobil joint venture in the UK and 9,650 employees in the Rest of Europe.

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 38 -- Pensions

Most Group companies have pension plans, the forms and benefits of which vary with conditions and practices in the countries concerned. Pension benefits may be provided through defined contribution plans (money purchase schemes) or defined benefit plans (final salary schemes). For defined contribution plans, retirement benefits are determined by the value of funds arising from contributions paid in respect of each employee. For defined benefit plans, retirement benefits are based on the employees' final pensionable salary and length of service. Defined benefit plans may be externally funded or unfunded. The assets of funded plans are generally held in separately administered trusts. Contributions to funded defined benefit plans are based on advice from independent actuaries using actuarial methods, the objective of which is to provide adequate funds to meet pension obligations as they fall due. No contributions were made to the UK and US pension funds during 2001. It is not expected that any contributions will be made in 2002. For unfunded plans, where assets are not held with the specific purpose of matching pension obligations the accrued liability for pension benefits is included within other provisions. The majority of the Group's employees are members of defined benefit schemes. The principal plans are reviewed annually by the independent actuaries and subject to a formal actuarial valuation every three years. The date of the latest actuarial valuation for the UK and US plans was January 1, 2001 and for the unfunded plans in Europe was January 1, 2002.

Pension costs for the principal plans have been derived using the projected unit credit method and by amortizing surpluses and deficits on a straight line basis over the average expected remaining service lives of the current employees. The main assumptions used in calculating the credit/charge for the principal plans were as follows:

	Years ended December 31,		
	2001	2000	1999
UK plans:			
Rate of return on assets	6.5%	6.5%	6.0%
Discount rate	6.5%	6.5%	6.0%
Future salary increases	5.0%	5.0%	4.5%

Future pension increases............	3.0%	3.0%	2.5%
Dividend growth.....................	n/a	n/a	n/a
Other European plans:			
Rate of return on assets............	n/a	n/a	n/a
Discount rate.......................	6.2%	6.2%	6.4%
Future salary increases.............	3.2%	3.2%	3.4%
Future pension increases............	2.1%	2.1%	2.3%
Dividend growth.....................	n/a	n/a	n/a
US plans:			
Rate of return on assets............	10.0%	10.0%	10.0%
Discount rate.......................	7.5%	7.5%	6.5%
Future salary increases.............	4.0%	4.0%	4.0%
Future pension increases............	nil	nil	nil
Dividend growth.....................	n/a	n/a	n/a

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n/a = not applicable

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 38 -- Pensions (continued)

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Principal plans:			
Service cost -- benefits earned during year........	397	364	347
Interest cost on projected benefit obligation......	1,309	1,211	999
Expected return on plan assets.....................	(1,717)	(1,625)	(1,273)
Amortization of transition asset...................	(66)	(72)	(83)
Recognized net actuarial gain......................	(169)	(203)	(108)
Recognized prior service cost......................	74	78	17
Curtailment and settlement (gains) losses..........	36	(119)	(150)
Special termination benefits.......................	175	233	3
	39	(133)	(248)
Other defined benefit plans..........................	73	38	30
Defined contribution schemes.........................	155	220	121
Total pension expense (income).......................	267	125	(97)

At January 1, 2001, the date of the latest actuarial valuations, the market value and actuarial value of assets in the Group's major externally funded pension plans in the UK and the USA was $26,587 million ($25,520 million at January 1, 2000) and $24,121 million ($20,474 million at January 1, 2000) respectively. The actuarial value of the assets of these plans represented 128% (2000 130%) of the benefits that had accrued to members of those plans, after allowing for expected future increases in salaries.

At December 31, 2001 the obligation for accrued benefits in respect of the major unfunded schemes in Europe was $1,510 million ($1,438 million at December 31, 2000). Of this amount, $1,317 million ($1,167 million at December 31, 2000) has been provided in these accounts.

The Group continues to account for pensions in accordance with Statement of Standard Accounting Practice No. 24 'Accounting for Pension Costs'. A new standard (Financial Reporting Standard No. 17 'Retirement Benefits') which changes the basis of accounting for pensions and other postretirement benefits will be adopted by the Group for its reporting for the year ended December 31, 2003. This new standard requires certain additional disclosures in accounting periods prior to its implementation. The additional disclosures for the year ended December 31, 2001 are set out below.

	UK	Other European	USA
Major assumptions as at December 31, 2001		(%)	
Rate of increase in salaries	4.5	3.2	4.0
Rate of increase to pensions in payment	2.5	2.0	--
Rate of increase to deferred pensions	2.5	2.0	--
Discount rate for scheme liabilities	6.0	6.2	7.25
Inflation	2.5	2.0	3.0

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 38 -- Pensions (continued)

The expected long-term rates of return and market values of the assets of the significant defined benefit plans at December 31, 2001 were as follows:

	UK		Other European		USA	
	Expected long-term rate of return	Market value	Expected long-term rate of return	Market value	Expected long-term rate of return	Market value
	(%)	($ million)	(%)	($ million)	(%)	($ million
Market value of assets at December 31, 2001						
Equities	7.5	12,228	n/a	--	11.0	4,537
Bonds	5.5	2,449	n/a	--	7.0	942
Property	6.5	1,057	n/a	--	8.0	51
Cash	4.5	1,146	n/a	--	4.0	95

	16,880	--	5,625
Present value of scheme liabilities	12,746	1,510	(6,146)
Surplus (deficit) in the plans	4,134	(1,510)	(521)
Deferred tax	(1,240)	422	193
	2,894	(1,088)	(328)

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 38 -- Pensions (concluded)

Further information in respect of the Group's principal defined benefit pension plans required under FASB Statement of Financial Accounting Standards No. 132 -- 'Employers' Disclosures about Pensions and Other Postretirement Benefits' is set out below.

	UK		Other European		US	
	2001	2000	2001	2000	2001	200
			($ million)			
Benefit obligation at January 1	13,213	11,077	1,438	1,513	5,546	3,82
Service cost	255	225	12	10	130	12
Interest cost	811	746	89	86	409	38
Plan amendments	--	809	--	--	16	-
Curtailments, settlements and special termination benefits	--	--	--	--	208	19
Actuarial (gain) loss	(646)	626	(42)	44	536	4
Acquisitions	--	1,241	189	--	101	2,30
Plan participants' contributions	26	24	--	--	--	-
Settlement payments	--	--	--	--	(9)	(42
Benefit payments	(546)	(563)	(101)	(94)	(791)	(90
Exchange adjustment	(367)	(972)	(75)	(121)	--	-
Benefit obligation at December 31	12,746	13,213	1,510	1,438	6,146	5,54
Fair value of plan assets at January 1	19,617	20,189	--	--	6,970	5,33
Actual return on plan assets	(1,689)	216	--	--	(682)	(11
Acquisitions	--	1,344	--	--	91	2,81
Plan participants' contributions	26	24	--	--	--	-
Employer contributions	27	14	--	--	46	29
Settlement payments	--	--	--	--	(9)	(44
Benefit payments	(546)	(563)	--	--	(791)	(90
Exchange adjustment	(555)	(1,607)	--	--	--	-
Fair value of plan assets at December 31	16,880	19,617	--	--	5,625	6,97

Funded status...............	4,134	6,404	(1,510)	(1,438)	(521)	1,42
Unrecognized transition (asset) obligation................	(154)	(237)	51	69	(1)	(
Unrecognized net actuarial (gain) loss	(2,537)	(5,021)	141	200	1,777	13
Unrecognized prior service cost	695	791	1	2	24	1
Net amount recognized.......	2,138	1,937	(1,317)	(1,167)	1,279	1,56
Prepaid benefit cost (accrued benefit liability)........	2,138	1,937	(1,454)	(1,391)	(147)	1,51
Intangible asset............	--	--	26	50	86	
Accumulated other comprehensive income......	--	--	111	174	1,340	4
	2,138	1,937	(1,317)	(1,167)	1,279	1,56

Note 39 -- Other postretirement benefits

Certain Group companies in the USA provide postretirement healthcare and life insurance benefits to their retired employees and dependants. The entitlement to these benefits is usually based on the employee remaining in service until retirement age and completion of a minimum period of service. The plans are funded to a limited extent and the accrued net liability for postretirement benefits is included within other provisions. The cost of providing postretirement benefits is assessed annually by independent actuaries using the projected unit credit method. The date of the latest actuarial valuation was January 1, 2001.

The assumptions used in calculating the charge for postretirement benefits are consistent with those shown in Note 38 for US pension plans.

The charge to income for postretirement benefits is as follows:

	Years ended December 31,		
	2001	2000	1999
		($ million)	
Service cost -- benefits earned during year..........	31	25	34
Interest cost on projected benefit obligation........	187	148	113
Expected return on plan assets......................	(5)	(5)	(4)
Recognized net actuarial gain.......................	(6)	(46)	(31)
Amortization of prior service cost recognized........	(15)	(20)	(8)
Curtailment gains..................................	(32)	(40)	(62)
Postretirement benefit expense......................	160	62	42

At December 31, 2001 the independent actuaries have reassessed the obligation for postretirement benefits at $3,080 million ($2,562 million at December 31, 2000). The provision for postretirement benefits at December 31, 2001 was $2,664 million ($2,726 million at December 31, 2000).

The discount rate used to assess the obligation at December 31, 2001 was 7.25% (7.5% at December 31, 2000). The assumed future healthcare cost trend rate for beneficiaries aged under 65 (over 65) for 2002 is 12% (15%), for 2003 is 10% (11%) and for 2004 is 8% (8%) and for 2005 and subsequent years is 5% (5%).

Note 39 -- Other postretirement benefits (continued)

As indicated in Note 38 -- Pensions, certain additional disclosures are required by FRS 17 for the year ended December 31, 2001. The expected long-term rates of return and market values of the assets of the postretirement benefits plans at December 31, 2001 were as follows:

	USA	
	Expected long-term rate of return	Market value
	(%)	($ million)
Market value of assets at December 31, 2001		
Equities	11.0	30
Bonds	7.0	11
		41
Present value of scheme liabilities		3,080
Other postretirement benefit liability before deferred tax		(3,039)
Deferred tax		1,124
		(1,915)

Note 39 -- Other postretirement benefits (concluded)

Further information presented in compliance with the requirements of FASB

Statement of Financial Accounting Standards No. 132 -- 'Employers' Disclosures about Pensions and Other Postretirement Benefits' is set out below.

	2001	2000
	($ million)	
Benefit obligation at January 1	2,562	1,638
Service cost	31	25
Interest cost	187	148
Plan amendments	78	--
Curtailment gain	(30)	(9)
Actuarial loss	476	340
Acquisitions	--	579
Benefit payments	(224)	(159)
Benefit obligation at December 31	3,080	2,562
Fair value of plan assets at January 1	49	53
Actual return on plan assets	(4)	--
Benefits payments	(4)	(4)
Fair value of plan assets at December 31	41	49
Funded status	(3,039)	(2,513)
Unrecognized net actuarial (gain) loss	349	(144)
Unrecognized prior service cost	26	(69)
Provision for postretirement benefits	(2,664)	(2,726)

The assumed healthcare cost trend rate has a significant effect on the amounts reported. A one-percentage-point change in the assumed healthcare cost trend rate would have the following effects:

	One-percentage point Increase	One-percentage point Decrease
	($ million)	
Effect on total of service and interest cost in 2001	32	(27)
Effect on postretirement obligation at December 31, 2001	339	(291)

Note 40 -- Contingent Liabilities

There were contingent liabilities at December 31, 2001 in respect of guarantees and indemnities entered into as part of the ordinary course of the Group's business. No material losses are likely to arise from such contingent liabilities.

Approximately 200 lawsuits were filed in State and Federal Courts in Alaska seeking compensatory and punitive damages arising out of the Exxon Valdez oil spill in Prince William Sound in March 1989. Most of those suits named Exxon (now ExxonMobil), Alyeska Pipeline Service Company (Alyeska), which operates the oil terminal at Valdez, and the other oil companies which own Alyeska. Alyeska initially responded to the spill until the response was taken over by Exxon. BP owns a 47% interest (reduced during 2001 from 50% by a sale of 3% to Phillips) in Alyeska through a subsidiary of BP America Inc. and briefly indirectly owned a further 20% interest in Alyeska following BP's combination with ARCO. Alyeska and its owners have settled all the claims against them under these lawsuits. Exxon has indicated that it may file a claim for contribution against Alyeska for a portion of the costs and damages which it has incurred. If any claims are asserted by Exxon which affect Alyeska and its owners, BP will defend the claims vigorously.

Since 1987, ARCO, a current subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the United States alleging injury to persons and property caused by lead pigment in paint. The majority of the lawsuits have been abandoned or dismissed as against ARCO. ARCO is named in these lawsuits as alleged successor to International Smelting and Refining which, along with a predecessor company, manufactured lead pigment during the period 1920-1946. Plaintiffs include individuals and governmental entities. Several of the lawsuits purport to be class actions. The lawsuits (depending on plaintiff) seek various remedies including: compensation to lead-poisoned children; cost to find and remove lead paint from buildings; medical monitoring and screening programmes; public warning and education on lead hazards; reimbursement of government healthcare costs and special education for lead-poisoned citizens; and punitive damages. No case has been settled or tried. While the amounts claimed could be substantial and it is not possible to predict the outcome of these legal actions, ARCO believes that it has valid defences and it intends to defend such actions vigorously. Consequently, BP believes that the impact of these lawsuits on the Group's results of operations, financial position or liquidity will not be material.

The Group is subject to numerous and local environmental laws and regulations concerning its products, operations and other activities. These laws and regulations may require the Group to take future action to remediate the effects on the environment of prior disposal or release of chemicals or petroleum substances by the Group or other parties. Such contingencies may exist for various sites including refineries, chemical plants, oil fields, service stations, terminals and waste disposal sites. In addition, the Group may have obligations relating to prior asset sales of closed facilities. The ultimate requirement for remediation and its cost are inherently difficult to estimate. However, the estimated cost of known environmental obligations has been provided in these accounts in accordance with the Group's accounting policies. While the amounts of future costs could be significant and could be material to the Group's results of operations in the period in which they are recognized, BP does not expect these costs to have a material effect on the Group's financial position or liquidity.

The Group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. This is because external insurance is not considered an economic means of financing losses for the Group. Losses will therefore be borne as they arise rather than being spread over time through insurance premia with attendant transaction costs. The position is reviewed periodically.

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 41 -- Joint ventures and associated undertakings

The significant joint ventures and associated undertakings of the BP Group at December 31, 2001 are shown in Note 44. Transactions between these entities and the Group are summarized below.

Sales to joint ventures and associated undertakings

	Product	2001 Sales	2001 Amount receivable at December 31	20 Sales	Amou receivable December
		($ million)		($ million)	
Joint ventures					
Pan American Energy	Crude oil	121	5	101	
BP/Mobil	Crude oil and products	--	--	2,933	
Watson Cogeneration	Natural gas	177	3	87	
Associated undertakings					
Erdoelchemie	Chemical feedstocks	250	--	718	
Ruhrgas	Natural gas	124	11	78	

Purchases from joint ventures and asssociated undertakings

	Product	2001 Purchases	2001 Amount payable at December 31	200 Purchases	Amou payable December
		($ million)		($ million)	
Joint ventures					
Pan American Energy	Crude oil	178	14	139	
BP/Mobil	Crude oil and products	--	--	1,762	
Watson Cogeneration	Electricity and steam	187	7	129	
Associated undertakings					
Abu Dhabi Marine Areas	Crude oil	555	37	671	
Abu Dhabi Petroleum	Crude oil	820	47	948	
Erdoelchemie	Petrochemicals	50	--	114	
Ruhrgas	Natural gas	18	--	--	

The pan-European refining and marketing joint venture with ExxonMobil was dissolved on August 1, 2000. Within the BP/Mobil joint venture, BP operated and had a 70% interest in the fuels refining and marketing operation and had a 49% interest in the lubricants business. On dissolution, BP acquired most of the

ExxonMobil assets used by the fuels refining and marketing operation. The sales and purchases shown above occurred in the period to August 1, 2000.

On May 2, 2001 BP purchased the outstanding 50% of Erdoelchemie, previously an associated undertaking. From that date it was fully consolidated. The sales and purchases shown above occurred in the period to May 1, 2001.

Note 42 -- Oil and gas exploration and production activities (a)

Capitalized costs at December 31

	UK	Rest of Europe	USA	Rest of World	Total
			($ million)		
2001					
Gross capitalized costs:					
Proved properties	23,607	2,912	43,070	22,820	92,409
Unproved properties	333	120	1,224	2,345	4,022
	23,940	3,032	44,294	25,165	96,431
Accumulated depreciation (b)	13,320	1,883	19,508	10,980	45,691
Net capitalized costs	10,620	1,149	24,786	14,185	50,740
2000					
Gross capitalized costs:					
Proved properties	24,319	2,683	38,494	19,607	85,103
Unproved properties	482	73	1,754	3,449	5,758
	24,801	2,756	40,248	23,056	90,861
Accumulated depreciation (b)	13,182	1,797	18,204	8,933	42,116
Net capitalized costs	11,619	959	22,044	14,123	48,745
1999					
Gross capitalized costs:					
Proved properties	22,874	2,738	35,826	14,166	75,604
Unproved properties	412	79	741	2,067	3,299
	23,286	2,817	36,567	16,233	78,903
Accumulated depreciation (b)	13,160	1,890	20,751	8,279	44,080
Net capitalized costs	10,126	927	15,816	7,954	34,823

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 42 -- Oil and gas exploration and production activities (a) (continued)

Costs incurred for the year ended December 31

	UK	Rest of Europe	USA	Rest of World	Total
			($ million)		
2001					
Acquisition of properties:					
Proved	--	--	--	47	47
Unproved	4	--	20	193	217
	4	--	20	240	264
Exploration and appraisal costs (c)	109	80	295	618	1,102
Development costs	930	271	3,723	1,934	6,858
Total costs	1,043	351	4,038	2,792	8,224
2000					
Acquisition of properties:					
Proved	2,954	--	9,152	2,647	14,753
Unproved	161	--	508	1,880	2,549
	3,115	--	9,660	4,527	17,302
Exploration and appraisal costs (c)	86	67	676	466	1,295
Development costs	808	153	2,328	1,274	4,563
Total costs	4,009	220	12,664	6,267	23,160
1999					
Acquisition of properties:					
Proved	--	--	396	--	396
Unproved	--	--	23	130	153
	--	--	419	130	549
Exploration and appraisal costs (c)	83	39	287	439	848
Development costs	676	71	1,212	956	2,915
Total costs	759	110	1,918	1,525	4,312

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 42 -- Oil and gas exploration and production activities (a) (continued)

Results of operations for the year ended December 31

	UK	Rest of Europe	USA	Rest of World	Total
			($ million)		
2001					
Turnover (d):					
Third parties	2,979	564	1,642	2,581	7,766
Sales between businesses	3,003	462	9,645	4,892	18,002
	5,982	1,026	11,287	7,473	25,768
Exploration expense	14	22	256	188	480
Production costs	878	91	1,379	915	3,263
Production taxes	559	17	384	688	1,648
Other costs (e)	25	33	1,743	1,534	3,335
Depreciation and amounts provided	1,353	115	3,034	1,115	5,617
	2,829	278	6,796	4,440	14,343
Profit before taxation (f)	3,153	748	4,491	3,033	11,425
Allocable taxes	1,046	379	933	1,016	3,374
Results of operations	2,107	369	3,558	2,017	8,051
2000					
Turnover (d):					
Third parties	3,538	926	4,242	2,446	11,152
Sales between businesses	3,191	138	6,755	5,593	15,677
	6,729	1,064	10,997	8,039	26,829
Exploration expense	36	42	257	264	599
Production costs	772	86	1,311	786	2,955
Production taxes	641	6	437	911	1,995
Other costs (e)	74	6	1,624	1,889	3,593
Depreciation and amounts provided	1,453	98	2,406	748	4,705
	2,976	238	6,035	4,598	13,847
Profit before taxation (f)	3,753	826	4,962	3,441	12,982
Allocable taxes	1,127	516	1,042	1,018	3,703
Results of operations	2,626	310	3,920	2,423	9,279

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 42 -- Oil and gas exploration and production activities (a) (continued)

Results of operations for the year ended December 31 (continued)

	UK	Rest of Europe	USA	Rest of World	Total
			($ million)		
1999					
Turnover (d):					
Third parties	2,258	644	4,738	2,216	9,856
Sales between businesses	2,251	108	1,283	2,938	6,580
	4,509	752	6,021	5,154	16,436
Exploration expense	51	20	172	305	548
Production costs	734	98	1,387	756	2,975
Production taxes	167	2	283	495	947
Other costs (e)	157	16	1,231	1,143	2,547
Depreciation and amounts provided	1,306	138	1,113	651	3,208
	2,415	274	4,186	3,350	10,225
Profit before taxation (f)	2,094	478	1,835	1,804	6,211
Allocable taxes	643	312	483	497	1,935
Results of operations	1,451	166	1,352	1,307	4,276

The Group's share of joint ventures' and associated undertakings' results of operations in 2001 was a profit of $246 million (2000 $293 million and 1999 $204 million) after deducting a tax charge of $138 million (2000 $97 million tax charge and 1999 $6 million tax credit).

The Group's share of joint ventures' and associated undertakings' net capitalized costs at December 31, 2001 was $3,078 million (December 31, 2000 $3,354 million and December 31, 1999 $1,442 million).

The Group's share of joint ventures' and associated undertakings' costs incurred in 2001 was $419 million (2000 $1,490 million and 1999 $49 million).

(a) This note relates to the requirements contained within the UK Statement of Recommended Practice 'Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities'. Midstream activities of natural gas gathering and distribution and the operation of the main pipelines and tankers are excluded. The main midstream activities are the Alaskan transportation facilities, the Forties Pipeline system and the Central Area Transmission System. The Group's share of joint ventures' and associated undertakings' activities is excluded from the tables and included in the footnotes with the exception of the Abu Dhabi operations which are included in the income and expenditure items above. Profits (losses) on sale of businesses and fixed assets relating to the oil and natural gas exploration and production activities, which have been accounted as exceptional items, are also excluded.

(b) Accumulated depreciation consists of depreciation, depletion and amortization related to oil and natural gas producing activities.

(c) Exploration and appraisal drilling expenditure and licence acquisition costs are initially capitalized within intangible fixed assets in accordance with the Group's accounting policy.

(d) Turnover represents sales of production excluding royalty oil where royalty is payable in kind.

Note 42 -- Oil and gas exploration and production activities (a) (concluded)

(e) Includes cost of royalty oil not taken in kind, property taxes and other government take.

(f) The exploration and production total replacement cost operating profit comprises:

	UK	Rest of Europe	USA	Rest of World	Total
			($ million)		
Year ended December 31, 2001					
Exploration and production activities......					
-- Group (as above).......................	3,153	748	4,491	3,033	11,425
-- Equity-accounted entities..............	--	--	--	384	384
Midstream activities......................	271	--	138	199	608
Total replacement cost operating profit	3,424	748	4,629	3,616	12,417
Year ended December 31, 2000					
Exploration and production activities					
-- Group (as above).......................	3,753	826	4,962	3,441	12,982
-- Equity-accounted entities..............	--	--	--	390	390
Midstream activities......................	290	--	152	198	640
Total replacement cost operating profit	4,043	826	5,114	4,029	14,012
Year ended December 31, 1999					
Exploration and production activities					
-- Group (as above)......................	2,094	478	1,835	1,804	6,211
-- Equity-accounted entities.............	--	--	45	153	198
Midstream activities.....................	216	9	256	93	574
Total replacement cost operating profit	2,310	487	2,136	2,050	6,983

Note 43 -- US generally accepted accounting principles

The consolidated financial statements of the BP Group are prepared in accordance with UK GAAP which differs in certain respects from US GAAP. The principal differences between US GAAP and UK GAAP for BP Group reporting relate to the following:

(a) Group consolidation

Where the Group conducts activities through a joint arrangement that is not carrying on a trade or business in its own right the Group accounts for its own assets, liabilities and cash flows of the activity measured according to the terms of the arrangement. For the Group this method of accounting applies to certain oil and natural gas activities and undivided interests in pipelines. US GAAP permits these activities to be accounted for by proportional consolidation, which is equivalent to UK GAAP.

Joint ventures and associated undertakings are accounted for by the equity method. UK GAAP requires the consolidated financial statements to show separately the Group proportion of operating profit or loss, exceptional items, inventory holding gains or losses, interest expense and taxation of joint ventures and associated undertakings. In addition the Group's share of turnover of joint ventures should be disclosed. For US GAAP the after tax profits or losses (for example operating results after exceptional items, inventory holding gains or losses, interest expense and taxation) are included in the income statement as a single line item.

UK GAAP requires the Group's share of the gross assets and gross liabilities of joint ventures to be shown on the face of the balance sheet whereas under US GAAP the net investment is included as a single line item.

Note 43 -- US generally accepted accounting principles (continued)

The following summarizes the reclassifications for joint ventures and associated undertakings necessary to accord with US GAAP.

	Year ended December 31, 2001		
	As reported	Reclassification	US presenta
	($ million)		
Consolidated statement of income			
Other income	694	692	1
Share of profits of JVs and associated undertakings	1,203	(1,203)	
Exceptional items before taxation	535	2	
Inventory holding gains (losses)	(1,900)	7	(1
Interest expense	1,670	(205)	1
Taxation	5,017	(297)	4
Profit for the year	8,010	--	8

	Year ended December 31, 2000		
	As reported	Reclassification	US presenta
		($ million)	
Consolidated statement of income			
Other income	805	1,416	2
Share of profits of JVs and associated undertakings	1,600	(1,600)	
Exceptional items before taxation	220	(24)	
Inventory holding gains (losses)	728	(229)	
Interest expense	1,770	(218)	1
Taxation	4,972	(219)	4
Profit for the year	11,870	--	11

	Year ended December 31, 1999		
	As reported	Reclassification	US presenta
		($ million)	
Consolidated statement of income			
Other income	414	1,399	1,
Share of profits of JVs and associated undertakings	1,158	(1,158)	
Exceptional items before taxation	(2,280)	1	(2,
Inventory holding gains (losses)	1,728	(547)	1,
Interest expense	1,316	(201)	1,
Taxation	1,880	(104)	1,
Profit for the year	5,008	--	5,

(b) Income statement

The income statement prepared under UK GAAP shows sub-totals for replacement cost profit before interest and tax, historical cost profit before interest and tax and profit after taxation. These line items are not recognized under US GAAP.

(c) Exceptional items

Under UK GAAP certain exceptional items are shown separately on the face of the income statement after operating profit. These items are profits or losses on the sale of fixed assets and businesses or sale or termination of operations and fundamental restructuring charges. Under US GAAP these items are classified as operating income or expenses.

Note 43 -- US generally accepted accounting principles (continued)

(d) Deferred taxation/Business combinations

Under the UK GAAP restricted liability method, deferred taxation is only provided where timing differences are expected to reverse in the foreseeable future. Under US GAAP deferred taxation is provided for temporary differences between the financial reporting basis and the tax basis of the Group's assets and liabilities at enacted tax rates.

US GAAP requires the recognition of a deferred tax asset or liability for the tax effects of differences between the assigned values and the tax bases of assets acquired and liabilities assumed in a purchase business combination, whereas under UK GAAP no such deferred tax asset or liability is recognized. Under US GAAP the deferred tax asset or liability is amortized over the same period as the assets and liabilities to which it relates.

The adjustments to profit for the year and to BP shareholders' interest to accord with US GAAP are summarized below.

Increase (decrease) in caption heading	Years ended December 31,		
	2001	2000	1999
	($ million)		
Replacement cost of sales	1,091	706	115
Increase in tax charge from restricted liability to gross potential	2,124	1,554	442
Taxation resulting from business combinations	(1,074)	(672)	(91)
Profit for the year	(2,141)	(1,588)	(466)

	At December 31,	
	2001	2000
	($ million)	
Tangible assets	7,032	8,367
Increase in provision from restricted liability to gross potential liability	10,047	8,014
Tax liability resulting from business combinations	7,014	8,336
BP shareholders' interest	(10,029)	(7,983)

The major components of deferred tax liabilities and assets on a US GAAP basis were as follows:

	At December 31,	
	2001	2000
	($ million)	
Depreciation	(19,709)	(20,399)
Other taxable temporary differences	(1,110)	(1,328)
Total deferred tax liabilities	(20,819)	(21,727)

Petroleum revenue tax	383	337
Decommissioning and other provisions	2,446	2,610
Tax credit and loss carry forward	1,487	1,113
Other deductible temporary differences	668	357
Gross deferred tax assets	4,984	4,417
Valuation allowance	(1,474)	(219)
Net deferred tax assets	3,510	4,198
Net deferred tax liability*	(17,309)	(17,529)

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* Primarily noncurrent.

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 43 -- US generally accepted accounting principles (continued)

(e) Provisions

UK GAAP requires provisions for decommissioning, environmental liabilities and onerous contracts to be determined on a discounted basis if the effect of the time value of money is material. Unwinding of discount and the effect of a change in the discount rate is included in interest expense in the period. When a decommissioning provision is set up, a tangible fixed asset of the same amount is also recognized and is subsequently depreciated as part of the capital costs of the facilities. Under US GAAP (i) environmental liabilities are discounted only where the timing and amounts of payments are fixed and reliably determinable and (ii) provisions for decommissioning are provided on a unit-of-production basis over field lives, there is no corresponding tangible fixed asset.

The adjustments to profit for the year and to BP shareholders' interest to accord with US GAAP are summarized below.

Increase (decrease) in caption heading	Years ended December 31,		
	2001	2000	1999
	($ million)		
Replacement cost of sales	523	340	121
Interest expense	(238)	(189)	(110)
Taxation	(103)	(83)	(20)
Profit for the year	(182)	(68)	9

At December 31,

	2001	2000
	($ million)	
Tangible assets	(785)	(402)
Provisions	780	921
Deferred taxation	(511)	(410)
BP shareholders' interest	(1,054)	(913)

(f) Impairment

Both UK and US GAAP require that long-lived assets and certain identifiable intangibles to be held and used by an entity be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. US GAAP requires, in performing the review for recoverability, the entity to estimate the future cash flows expected to result from the use of the asset and its eventual disposition. If the sum of the expected future cash flows (undiscounted and without interest charges) is less than the carrying amount of the asset, an impairment loss is recognized. Otherwise, no impairment loss is recognized. Measurement of an impairment loss for long-lived assets and identifiable intangibles that an entity expects to hold and use is based on the fair value of the assets.

For UK GAAP to the extent that the carrying amount exceeds the recoverable amount, that is the higher of net realizable value and value in use (fair value) the fixed asset is written down to its recoverable amount.

UK GAAP permits assets and liabilities acquired on a business combination to be revised in the year following that in which the acquisition was made. US GAAP does not permit such adjustments.

In 2001 a revision of $911 million to the previously reported fair values for tangible fixed assets relating to the 2000 acquisition of ARCO under UK GAAP has been reflected as a charge for impairment under US GAAP.

Note 43 -- US generally accepted accounting principles (continued)

(f) Impairment (concluded)

The adjustments to profit for the year to accord with US GAAP are shown below. There is no impact on BP shareholders' interest. The consequential balance sheet adjustments are reflected in (d) Deferred taxation/Business combinations and (h) Goodwill.

Increase (decrease) in caption heading	Years ended December 31,		
	2001	2000	1999
	($ million)		
Replacement cost of sales	1,150	--	--

Taxation	(239)	--	--
Profit for the year	(911)	--	--

(g) Sale and leaseback

The sale and leaseback of the Amoco building in Chicago, Illinois in 1998 is treated as a sale for UK GAAP whereas for US GAAP it is treated as a financing transaction.

A provision was recognized under UK GAAP in 1999 to cover the likely shortfall on rental income from subletting the Chicago office building. As the original sale and leaseback was not treated as a sale for US GAAP the provision has been reversed for US GAAP.

Under UK GAAP the profit arising on the sale and operating leaseback of certain railcars in 1999 is taken to income in the period in which the transaction occurs. Under US GAAP this profit is not recognized immediately but amortized over the term of the operating lease.

The adjustments to profit for the year and BP shareholders' interest to accord with US GAAP are summarized below.

Increase (decrease) in caption heading	Years ended December 31,		
	2001	2000	1999
	($ million)		
Replacement cost of sales	51	49	(123)
Exceptional items	--	--	(37)
Taxation	(15)	(15)	24
Profit for the year	(36)	(34)	62

	At December 31,	
	2001	2000
	($ million)	
Tangible assets	171	181
Other accounts payable and accrued liabilities	30	34
Provisions	(65)	(105)
Finance debt	413	413
Deferred taxation	(73)	(57)
BP shareholders' interest	(134)	(104)

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 43 -- US generally accepted accounting principles (continued)

(h) Goodwill

In 2001, under UK GAAP, revisions to the previously reported fair values of tangible fixed assets and the liability for taxation relating to the ARCO acquisition have resulted in a net increase of goodwill of $97 million. Under US GAAP, the revision to tangible fixed assets of $911 million is accounted as a charge for impairment. This results in a GAAP difference of $911 million in goodwill.

This adjustment plus other differences in the basis for determining goodwill between UK and US GAAP, result in goodwill for US GAAP being lower than for UK GAAP at the year end. The amortization of the difference is included within replacement cost of sales.

The adjustments to profit for the year and to BP shareholders' interest to accord with US GAAP are summarized below.

Increase (decrease) in caption heading	Years ended December 31,		
	2001	2000	1999
	($ million)		
Replacement cost of sales	68	48	--
Taxation	--	--	--
Profit for the year	(68)	(48)	--

	At December 31,	
	2001	2000
	($ million)	
Intangible assets	(348)	631
Deferred taxation	--	--
BP shareholders' interest	(348)	631

(i) Derivative financial instruments and hedging activities

On January 1, 2001 the Group adopted Statement of Financial Accounting Standards No. 133 'Accounting for Derivative Instruments and Hedging Activities' (SFAS 133) as amended by Statement Nos. 137 and 138, for US GAAP reporting.

SFAS 133, as amended, requires that all derivative instruments be recorded on the balance sheet at their fair value. Changes in the fair value of derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as part of a hedge transaction and, if it is, the type of hedge transaction. To the extent certain criteria are met, SFAS 133 permits, but does not require, hedge accounting.

The Group's accounting policies under UK GAAP do not satisfy the criteria for hedge accounting under SFAS 133. The Group does not intend to modify its practice under UK GAAP.

In the normal course of business the Group is a party to derivative financial instruments with off-balance sheet risk, primarily to manage its exposure to fluctuations in foreign currency exchange rates and interest rates, including management of the balance between floating rate and fixed rate debt. The Group also manages certain of its exposures to movements in oil and natural gas prices. In addition, the Group trades derivatives in conjunction with these risk management activities.

Note 43 -- US generally accepted accounting principles (continued)

(i) Derivative financial instruments and hedging activities (concluded)

All oil price derivatives and all derivatives held for trading are carried on the Group's balance sheet at fair value with changes in that value recognized in earnings of the period. For those derivative instruments, there was no impact of adopting SFAS 133 on the Group's results of operations and financial position, as adjusted to accord with US GAAP. Certain financial derivatives used to manage foreign currency and interest rate risk that qualify for hedge accounting under UK GAAP are marked to market under SFAS 133. For these derivatives, the cumulative effect of adopting SFAS 133 resulted in a pre-tax charge to income, as adjusted to accord with US GAAP, of $27 million ($18 million after tax) and a pre-tax credit to other comprehensive income of $57 million ($37 million after tax). The net gain included in other comprehensive income as of January 1, 2001 has been reclassified into earnings during 2001. Under US GAAP the fair values of derivative financial instruments are shown as current assets and liabilities as appropriate.

The Group has a number of long-term natural gas contracts which have been in place for many years. The pricing structure for those contracts is not directly related to the market price of natural gas but to the price of other commodities or indices, such as fuel oil or consumer price indices. SFAS 133 requires these contracts to be marked to market. On the basis of SFAS 133 Implementation Issue C11, the cumulative effect of adopting SFAS 133 for these derivatives resulted in a pre-tax charge to income, as adjusted to accord with US GAAP, at July 1, 2001 of $530 million ($344 million after tax).

Because the Company does not intend to modify its accounting practice to satisfy the criteria for hedge accounting under SFAS 133, the Group's results of operations, as adjusted to accord with US GAAP, will not necessarily be representative of the results it would report if US GAAP were used to prepare the consolidated financial statements of the Group and the Group sought to meet the hedge criteria of SFAS 133.

The adjustments to profit for the year and to BP shareholders' interest to accord with US GAAP are summarized below.

Increase (decrease) in caption heading	Years ended December 31,		
	2001	2000	1999
	($ million)		
Replacement cost of sales	481	--	--
Taxation	(168)	--	--
Profit for the year before cumulative effect of accounting change	(313)	--	--
Cumulative effect of accounting change, net of taxation	(362)	--	--
Profit for the year	(675)	--	--

	At December 31,	
	2001	2000
	($ million)	
Accounts payable and accrued liabilities	1,038	--
Deferred taxation	(363)	--
BP shareholders' interest	(675)	--

Note 43 -- US generally accepted accounting principles (continued)

(j) Gain arising on asset exchange

For UK GAAP the transaction with Solvay, which led to the exchange of businesses for an interest in a joint venture and an associated undertaking, has been treated as an asset swap which does not give rise to a gain or loss. Under US GAAP the transaction has been treated as a disposal and acquisition at fair value which gives rise to a pre-tax gain on disposal of $242 million ($157 million after tax).

The adjustments to profit for the year and to BP shareholders' interest to accord with US GAAP are summarized below.

Increase (decrease) in caption heading	Years ended December 31,		
	2001	2000	1999
	($ million)		

Profit (loss) on sale of fixed assets and businesses or termination of operations	242	--	--
Taxation	85	--	--
Profit for the year	157	--	--

	At December 31, 2001	2000
	($ million)	
Intangible assets	188	--
Accounts payable and accrued liabilities	(54)	--
Deferred taxation	85	--
BP shareholders' interest	157	--

(k) Ordinary shares held for future awards to employees

Under UK GAAP, Company shares held by an Employee Share Ownership Plan to meet future requirements of employee share schemes are recorded in the balance sheet as Fixed assets -- Investments. Under US GAAP, such shares are recorded in the balance sheet as a reduction of shareholders' interest.

The adjustment to BP shareholders' interest to accord with US GAAP is shown below.

Increase (decrease) in caption heading	At December 31, 2001	2000
	($ million)	
Fixed assets -- Investments	(266)	(360)
BP shareholders' interest	(266)	(360)

Note 43 -- US generally accepted accounting principles (continued)

(l) Dividends

Under UK GAAP, dividends are recorded in the year in respect of which they are announced or declared by the board of directors to the shareholders. Under US GAAP, dividends are recorded in the period in which dividends are declared.

The adjustment to BP shareholders' interest to accord with US GAAP is shown below.

Increase (decrease) in caption heading	At December 31, 2001	2000
	($ million)	
Other accounts payable and accrued liabilities	(1,288)	(1,178)
BP shareholders' interest	1,288	1,178

(m) Debt retirement charges

Under US GAAP charges arising on the early retirement of debt would be shown as an extraordinary item. Under UK GAAP they are included within interest expense.

(n) Investments

Under UK GAAP the Group's equity investments in Lukoil, Sinopec and PetroChina are held for the long term and reported as fixed asset investments and carried on the balance sheet at cost subject to review for impairment. For US GAAP these investments are classified as available-for-sale securities. Consequently they are reported at fair value, with unrealized holding gains and losses, net of tax, reported in accumulated other comprehensive income. If a decline in fair value below cost is 'other than temporary' the unrealized loss is accounted for as a realized loss and charged against income.

The adjustment to BP shareholders' interest to accord with US GAAP is shown below.

Increase (decrease) in caption heading	At December 31, 2001	2000
	($ million)	
Fixed assets -- Investments	(3)	(172)
Deferred taxation	(1)	(60)
BP shareholders' interest	(2)	(112)

Note 43 -- US generally accepted accounting principles (continued)

(o) Additional minimum pension liability

Where a pension plan has an unfunded accumulated benefit obligation, US GAAP requires such amount to be recognized as a liability in the balance sheet. The adjustment resulting from the recognition of any such minimum liability, including the elimination of amounts previously recognized as a prepaid benefit cost, is reported as an intangible asset to the extent of unrecognized prior service cost with the remaining amount reported in comprehensive income.

The adjustments to accumulated other comprehensive income (BP shareholders' interest) to accord with US GAAP are summarized below.

	At December 31,	
Increase (decrease) in caption heading	2001	2000
	($ million)	
Intangible assets	112	53
Other receivables falling due after more than one year	(1,015)	--
Noncurrent liabilities -- accounts payable and accrued liabilities	548	274
Deferred taxation	(509)	(76)
BP shareholders' interest	(942)	(145)

(p) Balance sheet

Under US GAAP Trade and Other receivables due after one year of $4,681 million at December 31, 2001 ($4,610 million at December 31, 2000), included within current assets, would have been classified as noncurrent assets. Borrowing under US Industrial Revenue/Municipal Bonds of $1,768 million (December 31, 2000 $1,671 million) included within Current liabilities - falling due within one year would, under US GAAP, have been classified as noncurrent liabilities. The provision for deferred taxation is primarily in respect of noncurrent items.

Note 43 -- US generally accepted accounting principles (continued)

The following is a summary of the adjustments to profit for the year and to BP shareholders' interest which would be required if generally accepted accounting principles in the USA (US GAAP) had been applied instead of those generally accepted in the United Kingdom (UK GAAP).

These results are stated using the first-in first-out method of stock valuation.

Profit for the year	2001	2000	1999
	Years ended December 31, ($ million except per share amounts)		
Profit as reported in the consolidated statement of income.....	8,010	11,870	5,008
Adjustments:			
Deferred taxation/business combinations (d)..................	(2,141)	(1,588)	(466)
Provisions (e)...	(182)	(68)	9
Impairment (f)...	(911)	--	--
Sale and leaseback (g).......................................	(36)	(34)	62
Goodwill (h)...	(68)	(48)	--
Derivative financial instruments (i).........................	(313)	--	--
Gain arising on asset exchange (j)...........................	157	--	--
Other..	10	51	(17)
Profit for the year before cumulative effect of accounting change as adjusted to accord with US GAAP....................	4,526	10,183	4,596
Cumulative effect of accounting change:			
Derivative financial instruments (i).........................	(362)	--	--
Profit for the year as adjusted to accord with US GAAP.	4,164	10,183	4,596
Dividend requirements on preference shares....................	2	2	2
Profit for the year applicable to ordinary shares as adjusted to accord with US GAAP..............................	4,162	10,181	4,594
Profit for the year as adjusted:			
Per ordinary share -- cents			
Basic -- before cumulative effect of accounting change........	20.16	47.05	23.70
Cumulative effect of accounting change.......................	(1.61)	--	--
	18.55	47.05	23.70
Diluted -- before cumulative effect of accounting change......	20.04	46.74	23.56
Cumulative effect of accounting change.......................	(1.60)	--	--
	18.44	46.74	23.56
Per American Depositary Share -- cents			
Basic -- before cumulative effect of accounting change........	120.96	282.30	142.20
Cumulative effect of accounting change.......................	(9.66)	--	--
	111.30	282.30	142.20
Diluted -- before cumulative effect of accounting change......	120.24	280.44	141.36
Cumulative effect of accounting change.......................	(9.60)	--	--
	110.64	280.44	141.36

Note 43 -- US generally accepted accounting principles (continued)

BP shareholders' interest

	At December 31, 2001	At December 31, 2000
	($ million)	
BP shareholders' interest as reported in the consolidated balance sheet	74,367	73,416
Adjustments:		
Deferred taxation/business combinations (d)	(10,029)	(7,983)
Provisions (e)	(1,054)	(913)
Sale and leaseback (g)	(134)	(104)
Goodwill (h)	(348)	631
Derivative financial instruments (i)	(675)	--
Gain arising on asset exchange (j)	157	--
Ordinary shares held for future awards to employees (k)	(266)	(360)
Dividends (l)	1,288	1,178
Investments (n)	(2)	(112)
Additional minimum pension liability (o)	(942)	(145)
Other	(40)	(54)
BP shareholders' interest as adjusted to accord with US GAAP	62,322	65,554

Comprehensive income

The components of comprehensive income, net of related tax are as follows:

	Years ended December 31, 2001	2000	1999
	($ million)		
Profit for the period as adjusted to accord with US GAAP	4,164	10,183	4,596
Currency translation differences	(908)	(2,508)	(921)
Net unrealized gain (loss) on investments	110	(112)	--
Additional minimum pension liability	(797)	(1)	(1)
Comprehensive income	2,569	7,562	3,674

Accumulated other comprehensive income at December 31, 2001 comprised currency translation losses of $4,790 million ($3,882 million at December 31, 2000), pension liability adjustments of $942 million ($145 million at December 31, 2000) and net unrealized losses on investments of $2 million ($112 million at December 31, 2000).

Note 43 -- US generally accepted accounting principles (continued)

Consolidated statement of cash flows

The Group's financial statements include a consolidated statement of cash flows in accordance with the revised UK Financial Reporting Standard No. 1 (FRS 1). The statement prepared under FRS 1 presents substantially the same information as that required under FASB Statement of Financial Accounting Standards No. 95 'Statement of Cash Flows' (SFAS 95).

Under FRS 1 cash flows are presented for (i) operating activities; (ii) dividends from joint ventures; (iii) dividends from associated undertakings; (iv) servicing of finance and returns on investments; (v) taxation; (vi) capital expenditure and financial investment; (vii) acquisitions and disposals; (viii) dividends; (ix) financing; and (x) management of liquid resources. SFAS 95 only requires presentation of cash flows from operating, investing and financing activities.

Cash flows under FRS 1 in respect of dividends from joint ventures and associated undertakings, taxation and servicing of finance and returns on investments are included within operating activities under SFAS 95. Interest paid includes payments in respect of capitalized interest, which under SFAS 95 are included in capital expenditure under investing activities. Cash flows under FRS 1 in respect of capital expenditure and acquisitions and disposals are included in investing activities under SFAS 95. Dividends paid are included within financing activities. All short-term investments are regarded as liquid resources for FRS 1. Under SFAS 95 short-term investments with original maturities of three months or less are classified as cash equivalents and aggregated with cash in the cash flow statement. Cash flows in respect of short-term investments with original maturities exceeding three months are included in operating activities.

Note 43 -- US generally accepted accounting principles (continued)

The statement of consolidated cash flows presented in accordance with SFAS 95 is as follows:

	Years ended December 31,		
	2001	2000	1999
	($ million)		

Operating activities			
Profit after taxation	8,083	11,962	5,146
Adjustments to reconcile profit after tax to net cash provided by operating activities:			
Depreciation and amounts provided	8,750	7,449	4,965
Exploration expenditure written off	238	264	304
Share of profits of joint ventures and associated undertakings less dividends received	(60)	(377)	(232)
(Profit) loss on sale of businesses and fixed assets	(537)	(196)	379
Working capital movement (a)	1,319	(2,848)	(1,877)
Other	(225)	(1,650)	215
Net cash provided by operating activities	17,568	14,604	8,900
Investing activities			
Capital expenditures	(12,295)	(10,220)	(6,314)
Acquisitions net of cash acquired	(1,210)	(6,265)	(102)
Investment in associated undertakings	(586)	(985)	(197)
Net investment in joint ventures	(497)	(218)	(750)
Proceeds from disposal of assets	2,903	11,362	2,441
Net cash used in investing activities	(11,685)	(6,326)	(4,922)
Financing activities			
Proceeds from shares (repurchased) issued	(1,100)	(2,039)	245
Proceeds from long-term financing	1,296	1,680	2,140
Repayments of long-term financing	(2,602)	(2,353)	(2,268)
Net increase (decrease) in short-term debt	1,434	(701)	837
Dividends paid -- Shareholders	(4,827)	(4,415)	(4,135)
-- Minority shareholders	(54)	(24)	(151)
Net cash used in financing activities	(5,853)	(7,852)	(3,332)
Currency translation differences relating to cash and cash equivalents	(53)	(50)	15
Increase (decrease) in cash and cash equivalents	(23)	376	661
Cash and cash equivalents at beginning of year	1,831	1,455	794
Cash and cash equivalents at end of year	1,808	1,831	1,455

(a) Working capital:			
Inventories decrease (increase)	1,490	(1,449)	(1,562)
Receivables decrease (increase)	1,905	(5,501)	(3,854)
Current liabilities -- excluding finance debt (decrease) increase	(2,076)	4,102	3,539
	1,319	(2,848)	(1,877)

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 43 -- US generally accepted accounting principles (continued)

Impact of new US accounting standards

Business combinations, goodwill and other intangible assets: In June 2001 the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No.141 'Business Combinations' (SFAS 141) and No. 142 'Goodwill and Other Intangible Assets' (SFAS 142). Under SFAS 141, the pooling of interest method of accounting is no longer permitted; the purchase method must be used for all business combinations initiated after June 30, 2001. SFAS 142, which is effective for accounting periods beginning after December 15, 2001, eliminates the requirement to amortize goodwill and indefinite lived intangible assets. Rather, such assets are subject to periodic impairment testing. Intangible assets that are not deemed to have an indefinite life will continue to be amortized over their estimated useful lives.

It is estimated that elimination of the requirement to amortize goodwill would increase the Group's results of operations, as adjusted to accord with US GAAP, by approximately $1,200 million for the year ended December 31, 2002, assuming no impairment of goodwill.

Asset retirement obligations: Also in June 2001 the FASB issued Statement of Financial Accounting Standards No. 143 'Accounting for Asset Retirement Obligations' (SFAS 143). SFAS 143 requires companies to record liabilities equal to the fair value of their asset retirement obligations when they are incurred (typically when the asset is installed at the production location). When the liability is initially recorded, companies capitalize an equivalent amount as part of the cost of the asset. Over time the liability is accreted for the change in its present value each period, and the initial capitalized cost is depreciated over the useful life of the related asset. SFAS 143 is effective for accounting periods beginning after June 15, 2002.

The provisions of SFAS 143 are similar to the accounting policy used by the Group in preparing its financial statements under UK GAAP. The Company has not yet determined the effect of adopting SFAS 143 on its results of operations or shareholders' interest as adjusted to accord with US GAAP.

Impairment or disposal of long-lived assets: In August 2001, the FASB issued Statement of Financial Accounting Standards No. 144, 'Accounting for the Impairment or Disposal of Long-Lived Assets' (SFAS 144). SFAS 144 retains the requirement to recognize an impairment loss only where the carrying value of a long-lived asset is not recoverable from its undiscounted cash flows and to measure such loss as the difference between the carrying amount and fair value of the asset. SFAS 144, among other things, changes the criteria that have to be met in order to classify an asset as held-for-sale and requires that operating losses from discontinued operations be recognized in the period that the losses are incurred rather than as of the measurement date. SFAS 144 is effective for accounting periods beginning after December 15, 2001.

The Company has not yet determined the effect of adopting SFAS 144 on its results of operations and shareholders' interest as adjusted to accord with US GAAP.

Impact of new UK accounting standards

Retirement benefits: In December 2000, the UK Accounting Standards Board issued Financial Reporting Standard No.17 'Retirement Benefits' (FRS 17). This standard is fully effective for accounting periods ending on or after June 22, 2003. Certain of the disclosure requirements are effective for periods prior to

2003. FRS 17 requires that financial statements reflect at fair value the assets and liabilities arising from an employer's retirement benefit obligations and any related funding. The operating costs of providing retirement benefits are recognized in the period in which they are earned together with any related finance costs and changes in the value of related assets and liabilities. The Company has not yet completed its evaluation of the impact of adopting FRS 17 on the Group's results of operations, and there will be no significant effect on the Group's financial position.

Note 43 -- US generally accepted accounting principles (concluded)

Impact of new UK accounting standards (concluded)

Deferred taxation: In December 2000, the UK Accounting Standards Board issued Financial Reporting Standard No.19 'Deferred Tax' (FRS 19). The standard requires that deferred tax should be provided in full on most timing differences. FRS 19 permits, but does not require, discounting of deferred tax assets and liabilities. The Group has adopted FRS 19 with effect from January 1, 2002. If this new standard had been applied to the reported results for 2001, the tax charge for the year under UK GAAP would have increased by $1,358 million to $6,375 million. In addition, at December 31, 2001 there would have been a reduction of $9,050 million in shareholders' funds and capital employed.

Note 44 -- Business and geographical analysis

BP has four reportable operating segments -- Exploration and Production, Gas and Power, Refining and Marketing and Chemicals. Exploration and Production's activities include oil and natural gas exploration and field development and production (upstream activities), together with pipeline transportation and natural gas processing (midstream activities). Gas and Power activities include marketing and trading of natural gas, liquefied natural gas, natural gas liquids and power, the development of international opportunties that monetize upstream gas resources and involvement in select power projects. The activities of Refining and Marketing include oil supply and trading as well as refining and marketing (downstream activities). Chemicals activities include petrochemicals manufacturing and marketing.

The Group is managed on a unified basis. Reportable segments are differentiated by the activities that each undertakes and the products they manufacture and market.

The accounting policies of operating segments are the same as those described in Note 1, Accounting Policies. Performance is evaluated based on replacement cost operating profit or loss, which excludes exceptional items, inventory holding gains and losses, interest income and expense, taxation and minority shareholders' interests.

Sales between segments are made at prices that approximate market prices taking into account the volumes involved.

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 44 -- Business and geographical analysis (continued)

By business

	Exploration and Production	Gas and Power	Refining and Marketing	Chemicals	Other businesses and corporate(
			($ million)		
2001					
Group turnover -- third parties........	8,569	36,254	117,330	11,282	783
-- sales between businesses (b).......	19,660	2,954	2,903	233	--
	28,229	39,208	120,233	11,515	783
Share of sales by joint ventures					
Equity accounted income (c)...........	559	184	278	107	75
Total replacement cost operating profit (loss) (d)..................	12,417	521	3,625	128	(556)
Exceptional items (e).................	195	(1)	471	(297)	167
Inventory holding gains (losses)	(6)	(81)	(1,583)	(230)	--
Historical cost profit (loss) before interest and tax....................	12,606	439	2,513	(399)	(389)
Total assets (f)......................	69,572	5,313	43,102	15,098	8,073
Operating capital employed (g).........	59,701	2,764	24,868	11,996	1,850
Depreciation and amounts provided (h)..	5,987	54	2,250	588	109
Capital expenditure and acquisitions (i)	8,861	359	2,415	1,926	563
2000					
Group turnover -- third parties.......	14,155	20,667	101,960	11,031	249
-- sales between businesses (b).......	16,787	346	5,923	216	--

	30,942	21,013	107,883	11,247	249
Share of sales by joint ventures.......					
Equity accounted income (c)...........	613	162	599	184	42
Total replacement cost operating profit (loss) (d)....................	14,012	571	3,523	760	(1,110)
Exceptional items (e).................	119	1	98	(212)	214
Inventory holding gains (losses).......	4	11	620	93	--
Historical cost profit (loss) before interest and tax....................	14,135	583	4,241	641	(896)
Total assets (f)......................	65,904	6,605	45,785	13,674	11,970
Operating capital employed (g).........	56,500	2,997	27,804	11,008	2,385
Depreciation and amounts provided (h)..	5,156	47	1,715	704	91
Capital expenditure and acquisitions (i)	6,383	336	8,693	1,585	30,616

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 44 -- Business and geographical analysis (continued)

By business

	Exploration and Production	Gas and Power	Refining and Marketing	Chemicals	Other businesses and corporate(
				($ million)	
1999					
Group turnover -- third parties.........	9,070	7,629	57,619	9,050	198
-- sales between businesses (b)........	10,063	444	2,524	342	--
	19,133	8,073	60,143	9,392	198
Share of sales by joint ventures........					
Equity accounted income (c)............	297	179	503	125	54
Total replacement cost operating profit (loss) (d)....................	6,983	211	1,840	686	(826)
Exceptional items (e)..................	(1,111)	14	(334)	(257)	(592)

Inventory holding gains (losses)	(1)	--	1,613	116	--
Historical cost profit (loss) before interest and tax	5,871	225	3,119	545	(1,418)
Total assets (f)	44,967	2,831	26,099	13,021	2,643
Operating capital employed (g)	36,229	2,242	13,209	10,048	1,192
Depreciation and amounts provided (h)	3,704	46	765	632	206
Capital expenditure and acquisitions (i)	4,194	81	1,571	1,215	284

By geographical area

	UK(j)	Rest of Europe	USA	Rest of World	Eliminatio
			($ million)		
2001					
Group turnover -- third parties (k)	34,151	29,098	83,757	27,212	
-- sales between areas	13,467	7,603	939	6,699	(28,7
	47,618	36,701	84,696	33,911	(28,7
Share of sales by joint ventures	13	30	318	810	
Equity accounted income (c)	11	235	309	648	
Total replacement cost operating profit (d)	2,668	1,814	7,049	4,604	
Exceptional items (e)	(319)	33	289	532	
Inventory holding gains (losses)	(225)	(444)	(1,014)	(217)	
Historical cost profit before interest and tax	2,124	1,403	6,324	4,919	
Total assets (f)	29,951	15,287	62,254	33,666	
Operating capital employed (g)	19,477	7,346	44,292	30,064	
Depreciation and amounts provided (h)	2,159	513	4,829	1,487	
Capital expenditure and acquisitions (i)	2,128	1,787	6,160	4,049	

Note 44 -- Business and geographical analysis (continued)

	UK(j)	Rest of Europe	USA	Rest of World	Eliminatio
			($ million)		

2000					
Group turnover -- third parties (k)....	34,430	18,642	70,255	24,735	
-- sales between areas	10,970	1,911	829	6,279	(19,9
	45,400	20,553	71,084	31,014	(19,9
Share of sales by joint ventures.......	3,314	12,316	270	686	(2,8
Equity accounted income (c)...........	144	525	290	641	
Total replacement cost operating profit (d)	3,773	2,013	7,296	4,674	
Exceptional items (e).................	12	(19)	459	(232)	
Inventory holding gains (losses).......	103	107	387	131	
Historical cost profit before interest and tax....................	3,888	2,101	8,142	4,573	
Total assets (f)......................	35,713	14,584	62,141	31,500	
Operating capital employed (g).........	20,093	7,087	44,657	28,857	
Depreciation and amounts provided (h)..	1,945	373	4,088	1,307	
Capital expenditure and acquisitions (i)	7,438	2,041	34,037	4,097	
1999					
Group turnover -- third parties (k).....	25,817	5,332	37,405	15,012	
-- sales between areas	4,406	641	1,381	4,453	(10,8
	30,223	5,973	38,786	19,465	(10,8
Share of sales by joint ventures	3,988	16,114	155	342	(2,9
Equity accounted income (c)............	48	619	198	293	
Total replacement cost operating profit (d)	2,111	1,167	3,001	2,615	
Exceptional items (e)..................	(237)	(258)	(983)	(802)	
Inventory holding gains (losses)........	151	494	839	244	
Historical cost profit before interest and tax.....................	2,025	1,403	2,857	2,057	
Total assets (f).......................	22,867	8,865	38,223	19,606	
Operating capital employed (g)..........	14,298	4,884	27,426	16,312	
Depreciation and amounts provided (h)...	1,582	261	2,358	1,152	
Capital expenditure and acquisitions (i)	1,518	831	2,963	2,033	

(a) Other businesses and corporate comprises Finance, BP Solar, the Group's coal asset and aluminium asset, its investment in PetroChina and Sinopec, interest income and costs relating to corporate activities worldwide.

(b) Sales and transfers between businesses are made at market prices taking into account the volumes involved.

(c) Equity accounted income (loss) represents the Group's share of income (loss) before interest expense and taxes of joint ventures and associated undertakings.

(d) Total replacement cost operating profit (loss) is before inventory holding gains and losses and interest expense, which is attributable to the corporate function.

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 44 -- Business and geographical analysis (concluded)

(e) Exceptional items comprise profit on sale of fixed assets and sale of businesses or termination of operations of $535 million in 2001 (2000 $220 million profit and 1999 $337 million loss) and restructuring costs in 1999 of $1,943 million.

(f) Total assets comprise fixed and current assets and include investments in joint ventures and associated undertakings analyzed between activities as follows:

	Exploration and Production	Gas and Power	Refining and Marketing	Chemicals	Other businesses and corporate(a)	Total
			($ million)			
2001	5,326	857	1,675	1,416	154	9,428
2000	5,093	744	1,220	1,155	127	8,339
1999	2,550	762	4,771	1,350	105	9,538

(g) Operating capital employed comprises net assets before deducting finance debt and liabilities for current and deferred taxation.

(h) Depreciation consists of charges for depreciation, depletion and amortization of property, plant and equipment, exploration expense and amounts provided against fixed asset investments.

(i) Capital expenditure and acquisitions includes $170 million in 2000 and $624 million in 1999 for the BP/Mobil joint venture.

(j) United Kingdom area includes the UK-based international activities of Refining and Marketing.

(k) Turnover to third parties is stated by origin which is not materially different from turnover by destination.

Note 45 -- Summarized financial information on joint ventures and associated undertakings

A summarized statement of income and assets and liabilities based on latest information available, with respect to the Group's equity accounted joint ventures and associated undertakings, is set out below:

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Sales and other operating revenue	27,503	45,335	41,180
Gross profit	5,164	8,968	7,715
Profit for the year	3,105	4,219	2,641

	At December 31,	
	2001	2000
	($ million)	
Fixed and other assets	25,175	24,893
Current assets	14,402	12,606
	39,577	37,499
Current liabilities	(10,022)	(9,271)
Noncurrent liabilities	(9,365)	(10,628)
Net assets	20,190	17,600

Note 45 -- Summarized financial information on joint ventures and associated undertakings (concluded)

The more important joint ventures and associated undertakings of the Group at December 31, 2001 and the percentage of equity capital owned or joint venture interest are:

	%	Country of operation	Principal a
Associated undertakings			
Abu Dhabi Marine Areas	37	Abu Dhabi	Crude oil p
Abu Dhabi Petroleum	24	Abu Dhabi	Crude oil p
BP Solvay Polyethylene North America	49	USA	Chemicals
China American Petroleum Co.	50	Taiwan	Chemicals

Ruhrgas	25	Germany	Gas distrib
Rusia Petroleum	25	Russia	Exploration
Sidanco (a)	11	Russia	Integrated
Joint ventures			
BP Solvay Polyethylene Europe	50	Europe	Chemicals
CaTO Finance Partnership	50	UK	Finance
Lukarco	46	Kazakhstan	Exploration
Malaysia - Thailand Joint Development Area	25	Thailand	Exploration
Pan American Energy	60	Argentina	Exploration
Unimar Company Texas (Partnership)	50	Indonesia	Exploration
Watson Cogeneration	51	USA	Power gener

(a) 25% voting interest.

Note 46 -- Transfer of natural gas liquids business

With effect from January 1, 2001, the NGL business in North America was transferred from Refining and Marketing to Gas and Power. Comparative information for 2000 and 1999 has been restated to reflect this change.

December 31, 2000	As restated		As reported	
	Gas and Power	Refining and Marketing	Gas and Power	Refining and Marketing
	($ million except for number of employees)			
Turnover	21,013	107,883	16,081	112,815
Group replacement cost operating profit	409	2,924	24	3,309
Joint ventures	--	433	--	433
Associated undertakings	162	166	162	166
Total replacement cost operating profit	571	3,523	186	3,908
Exceptional items	1	98	--	99
Replacement cost profit before interest and tax	572	3,621	186	4,007
Inventory holding gains (losses)	11	620	11	620
Capital expenditure and acquisitions	336	8,693	279	8,750
Operating capital employed	2,997	27,804	1,735	29,066
Tangible assets	1,322	17,619	472	18,469
Number of employees -- year end	1,600	67,100	1,000	67,700
Number of employees -- average	1,500	59,800	900	60,400

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 46 -- Transfer of natural gas liquids business (concluded)

December 31, 1999	As restated		As reported	
	Gas and Power	Refining and Marketing	Gas and Power	Refining and Marketing
	($ million except for number of employees)			
Turnover	8,074	60,142	5,323	62,893
Group replacement cost operating profit	258	1,111	32	1,337
Joint ventures	--	380	--	380
Associated undertakings	179	123	179	123
Total replacement cost operating profit	437	1,614	211	1,840
Exceptional items	(1)	(319)	14	(334)
Replacement cost profit before interest and tax	436	1,295	225	1,506
Inventory holding gains (losses)	--	1,613	--	1,613
Number of employees -- year end	1,400	44,650	800	45,250
Number of employees -- average	1,400	47,900	800	48,500

Note 47 -- Condensed consolidating information on certain US subsidiaries

BP p.l.c. fully and unconditionally guarantees certain publicly issued debt of its 100% owned subsidiary BP America Inc. BP p.l.c. also fully and unconditionally guarantees the payment obligations of its 100% owned subsidiary BP Exploration (Alaska) Inc. under the BP Prudhoe Bay Royalty Trust. The following financial information for BP p.l.c., BP America Inc. and BP Exploration (Alaska) Inc. and all other subsidiaries on a condensed consolidating basis is intended to provide investors with meaningful and comparable financial information about BP p.l.c. and its subsidiary issuers of debt securities and is provided pursuant to Rule 3-10 of Regulation S-X in lieu of the separate financial statements of each subsidiary issuer of public debt securities. Investments include the investments in subsidiaries recorded under the equity method for the purposes of the condensed consolidating financial information. Equity income of subsidiaries is the Group's share of replacement cost operating profit related to such investments. The eliminations and reclassifications column includes the necessary amounts to eliminate the intercompany balances and transactions between BP p.l.c., BP America Inc., BP Exploration (Alaska) Inc. and other subsidiaries.

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 47 -- Condensed consolidating information on certain US subsidiaries (continued)

Income statement

	Issuer	Issuer	Guarantor	
	BP America Inc.	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries
			($ million)	
For the year ended December 31, 2001				
Turnover	1,243	1,919	--	174,146
Less: Joint ventures	--	--	--	1,171
Group turnover	1,243	1,919	--	172,975
Replacement cost of sales	1,351	971	--	146,753
Production taxes	--	192	--	1,497
Gross profit	(108)	756	--	24,725
Distribution and administration expenses	21	5	846	10,046
Exploration expense	--	55	--	425
	(129)	696	(846)	14,254
Other income	317	1	1,365	351
Group replacement cost operating profit	188	697	519	14,605
Share of profits of joint ventures	--	--	--	443
Share of profits of associated undertakings	--	--	--	760
Equity-accounted income of subsidiaries	12,460	552	16,761	--
Total replacement cost operating profit	12,648	1,249	17,280	15,808
Profit (loss) on sale of businesses or termination of operations	--	--	(68)	--
Profit (loss) on sale of fixed assets	517	1	601	760
Replacement cost profit before interest and tax	13,165	1,250	17,813	16,568
Inventory holding gains (losses)	(1,087)	(11)	(1,900)	(1,896)
Historical cost profit before interest and tax	12,078	1,239	15,913	14,672
Interest expense	1,657	101	2,886	2,567
Profit before taxation	10,421	1,138	13,027	12,105
Taxation	3,617	272	5,017	4,896
Profit after taxation	6,804	866	8,010	7,209
Minority shareholders' interest	--	--	--	73
Profit for the year	6,804	866	8,010	7,136

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 47 -- Condensed consolidating information on certain US subsidiaries (continued)

Income statement (continued)

The following is a summary of the adjustments to the profit for the period which would be required if generally accepted accounting principles in the United States (US GAAP) had been applied instead of those generally accepted in the United Kingdom.

	Issuer	Issuer	Guarantor	
	BP America Inc.	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries
			($ million)	
For the year ended December 31, 2001				
Profit as reported	6,804	866	8,010	7,136
Adjustments:				
Deferred taxation/business combinations	(1,611)	(265)	(2,141)	(1,642)
Provisions	(32)	(5)	(182)	(177)
Impairment	(911)	--	(911)	(911)
Sale and leaseback	(36)	--	(36)	(36)
Goodwill	(68)	--	(68)	(68)
Derivative financial instruments	(73)	--	(313)	(313)
Gain arising on asset exchange	123	--	157	157
Other	--	--	10	10
Profit for the year before cumulative effect of accounting change as adjusted to accord with US GAAP	4,196	596	4,526	4,156
Cumulative effect of accounting change: Derivative financial instruments	(13)	--	(362)	(362)
Profit for the year as adjusted to accord with US GAAP	4,183	596	4,164	3,794

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 47 -- Condensed consolidating information on certain US subsidiaries (continued)

Income statement (continued)

Issuer	Issuer	Guarantor

	BP America Inc.	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries
			($ million)	
For the year ended December 31, 2000				
Turnover	--	2,665	--	161,826
Less: Joint ventures	--	--	--	13,764
Group turnover	--	2,665	--	148,062
Replacement cost of sales	70	1,126	--	122,366
Production taxes	--	276	--	1,785
Gross profit	(70)	1,263	--	23,911
Distribution and administration expenses	1	25	603	8,702
Exploration expense	--	26	--	573
	(71)	1,212	(603)	14,636
Other income	249	(12)	545	562
Group replacement cost operating profit	178	1,200	(58)	15,198
Share of profits of joint ventures	--	--	--	808
Share of profits of associated undertakings	--	--	--	792
Equity-accounted income of subsidiaries	12,519	282	18,155	--
Total replacement cost operating profit	12,697	1,482	18,097	16,798
Profit (loss) on sale of businesses or termination of operations	(11)	--	26,049	(90)
Profit (loss) on sale of fixed assets	452	(1)	88	111
Replacement cost profit before interest and tax	13,138	1,481	44,234	16,819
Inventory holding gains (losses)	444	(6)	728	728
Historical cost profit before interest and tax	13,582	1,475	44,962	17,547
Interest expense	1,347	22	2,203	1,727
Profit before taxation	12,235	1,453	42,759	15,820
Taxation	3,503	552	4,972	4,764
Profit after taxation	8,732	901	37,787	11,056
Minority shareholders' interest	--	--	--	92
Profit for the year	8,732	901	37,787	10,964

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 47 -- Condensed consolidating information on certain US subsidiaries (continued)

Income statement (continued)

The following is a summary of the adjustments to the profit for the period which would be required if generally accepted accounting principles in the United States (US GAAP) had been applied instead of those generally accepted in the United Kingdom.

	Issuer	Issuer	Guarantor	
	BP America Inc.	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries
	($ million)			
For the year ended December 31, 2000				
Profit as reported	8,732	901	37,787	10,964
Adjustments:				
Deferred taxation/business combinations	(1,515)	(47)	(1,588)	(1,426)
Provisions	(24)	(18)	(68)	(50)
Sale and leaseback	(34)	--	(34)	(34)
Goodwill	(48)	--	(48)	(48)
Other	--	--	51	51
Profit for the year as adjusted to accord with US GAAP	7,111	836	36,100	9,457

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 47 -- Condensed consolidating information on certain US subsidiaries (continued)

Income statement (continued)

	Issuer	Issuer	Guarantor	
	BP America Inc.	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries
	($ million)			
Year ended December 31, 1999				
Turnover	--	2,065	--	101,180
Less: Joint ventures	--	--	--	17,614
Group turnover	--	2,065	--	83,566

Replacement cost of sales	--	1,487	--	69,214
Production taxes	--	272	--	745
Gross profit	--	306	--	13,607
Distribution and administration expenses	67	36	473	5,488
Exploration expense	--	22	--	526
	(67)	248	(473)	7,593
Other income	14	--	465	398
Group replacement cost operating profit	(53)	248	(8)	7,991
Share of profits of joint ventures	--	--	--	555
Share of profits of associated undertakings	--	--	--	603
Equity-accounted income of subsidiaries	5,545	134	9,206	--
Total replacement cost operating profit	5,492	382	9,198	9,149
Profit (loss) on sale of businesses or termination of operations	2	--	356	339
Profit (loss) on sale of fixed assets	252	--	(700)	(700)
Restructuring costs	(1,263)	(61)	(1,943)	(1,799)
Replacement cost profit before interest and tax	4,483	321	6,911	6,989
Inventory holding gains (losses)	858	40	1,728	1,728
Historical cost profit before interest and tax	5,341	361	8,639	8,717
Interest expense	985	41	1,758	1,441
Profit before taxation	4,356	320	6,881	7,276
Taxation	803	78	1,880	1,881
Profit after taxation	3,553	242	5,001	5,395
Minority shareholders' interest	--	--	--	138
Profit for the year	3,553	242	5,001	5,257

Note 47 -- Condensed consolidating information on certain US subsidiaries (continued)

Income statement (concluded)

The following is a summary of the adjustments to the profit for the period which would be required if generally accepted accounting principles in the United States (US GAAP) had been applied instead of those generally accepted in the United Kingdom.

Issuer	Issuer	Guarantor

	BP America Inc.	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries
			($ million)	
For the year ended December 31, 1999				
Profit as reported	3,553	242	5,001	5,257
Adjustments:				
Deferred taxation/business combinations	(88)	37	(466)	(461)
Provisions	27	7	9	(6)
Sale and leaseback	62	--	62	62
Other	--	--	(17)	(17)
Profit for the year as adjusted to accord with US GAAP	3,554	286	4,589	4,835

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 47 -- Condensed consolidating information on certain US subsidiaries (continued)

Balance sheet

	Issuer	Issuer	Guarantor	
	BP America Inc.	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries
			($ million)	
At December 31, 2001				
Fixed assets				
Intangible assets	1,190	489	--	15,104
Tangible assets	--	6,418	--	70,992
Investments				
Joint ventures	--	--	--	3,861
Associated undertakings	--	--	3	5,564
Other	--	--	266	2,353
Subsidiaries - equity accounted basis	72,879	1,941	86,083	--
	72,879	1,941	86,352	11,778
Total fixed assets	74,069	8,848	86,352	97,874
Current assets				
Business held for resale	--	--	--	--
Inventories	5	92	--	7,534
Receivables - amounts falling due:				

Within one year	2,090	132	2,700	28,745
After more than one year	5,597	15,201	18,572	19,905
Investments	22	--	--	428
Cash at bank and in hand	(2)	(29)	3	1,386
	7,712	15,396	21,275	57,998
Current liabilities - amounts falling due within one year				
Finance debt	5,190	406	--	6,302
Other payables	89	252	7,642	29,707
Net current assets (liabilities)	2,433	14,738	13,633	21,989
Total assets less current liabilities	76,502	23,586	99,985	119,863
Noncurrent liabilities				
Finance debt	4,394	--	--	11,991
Other payables	824	10,795	191	41,812
Provisions for liabilities and charges				
Deferred taxation	--	--	--	1,655
Other	48	387	216	10,831
Net assets	71,236	12,404	99,578	53,574
Minority shareholders' interest - equity	--	--	--	627
BP shareholders' interest	71,236	12,404	99,578	52,947

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 47 -- Condensed consolidating information on certain US subsidiaries (continued)

Balance sheet (continued)

	Issuer	Issuer	Guarantor	
	BP America Inc.	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries
			($ million)	
At December 31, 2001				
Capital and reserves				
Capital shares	8	1,050	5,629	--
Paid in surplus	32,267	3,145	4,014	--
Merger reserve	--	--	26,286	697
Other reserves	--	--	223	--
Retained earnings	38,961	8,209	63,426	52,250
	71,236	12,404	99,578	52,947

The following is a summary of the adjustments to BP shareholders' interest which would be required if generally accepted accounting principles in the United States (US GAAP) had been applied instead of those generally accepted in the United Kingdom.

	Issuer	Issuer	Guarantor	
	BP America Inc.	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries
			($ million)	
BP shareholders' interest as reported......	71,236	12,404	99,578	52,947
Adjustments:				
Deferred taxation/business combinations..	(8,626)	(1,573)	(10,029)	(8,287)
Provisions..............................	(585)	(186)	(1,054)	(1,141)
Sale and leaseback......................	(134)	--	(134)	(134)
Goodwill................................	(348)	--	(348)	(348)
Derivative financial instruments.........	(86)	--	(675)	(675)
Gain arising on asset exchange...........	123	--	157	157
Ordinary shares held for future awards to employees..........................	--	--	(266)	(266)
Dividends...............................	--	--	1,288	1,288
Investments.............................	32	--	(2)	(2)
Additional minimum pension liability.....	(912)	--	(942)	(942)
Other...................................	--	--	(40)	(40)
BP shareholders' interest as adjusted to accord with US GAAP...................	60,700	10,645	87,533	42,557

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 47 -- Condensed consolidating information on certain US subsidiaries (continued)

Balance sheet (continued)

	Issuer	Issuer	Guarantor	
	BP America Inc.	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries
			($ million)	
At December 31, 2000				

Fixed assets				
Intangible assets	1,330	512	--	16,381
Tangible assets	7	5,942	--	69,224
Investments				
Joint ventures	--	--	--	2,884
Associated undertakings	--	--	3	5,452
Other	--	--	360	3,054
Subsidiaries - equity accounted basis	66,114	619	77,826	--
	66,114	619	78,189	11,390
Total fixed assets	67,451	7,073	78,189	96,995
Current assets				
Business held for resale	--	--	--	636
Inventories	--	75	--	9,159
Receivables - amounts falling due:				
Within one year	1,788	1,335	3,929	23,490
After more than one year	10,004	13,576	19,466	5,782
Investments	5	--	--	656
Cash at bank and in hand	--	(32)	2	1,200
	11,797	14,954	23,397	40,923
Current liabilities - amounts falling due within one year				
Finance debt	8,531	--	--	5,969
Other payables	119	644	2,582	38,784
Net current assets (liabilities)	3,147	14,310	20,815	(3,830)
Total assets less current liabilities	70,598	21,383	99,004	93,165
Noncurrent liabilities				
Finance debt	870	1,150	--	13,902
Other payables	5,246	9,482	178	18,820
Provisions for liabilities and charges				
Deferred taxation	--	(5)	--	1,827
Other	49	269	197	10,458
Net assets	64,433	10,487	98,629	48,158
Minority shareholders' interest - equity	--	--	--	585
BP shareholders' interest	64,433	10,487	98,629	47,573

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 47 -- Condensed consolidating information on certain US subsidiaries (continued)

Balance sheet (concluded)

	Issuer	Issuer	Guarantor	
	BP America Inc.	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries
	($ million)			
At December 31, 2000				
Capital and reserves				
Capital shares	8	--	5,653	--
Paid in surplus	32,267	3,145	3,770	--
Merger reserve	--	--	26,172	697
Other reserves	--	--	456	--
Retained earnings	32,158	7,342	62,578	46,876
	64,433	10,487	98,629	47,573

The following is a summary of the adjustments to BP shareholders' interest which would be required if generally accepted accounting principles in the United States (US GAAP) had been applied instead of those generally accepted in the United Kingdom.

	Issuer	Issuer	Guarantor	
	BP America Inc.	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries
	($ million)			
BP shareholders' interest as reported	64,433	10,487	98,629	47,573
Adjustments:				
Deferred taxation/business combinations	(7,141)	(1,353)	(7,983)	(6,949)
Provisions	(716)	(183)	(913)	(497)
Sale and leaseback	(104)	--	(104)	(104)
Goodwill	631	--	631	631
Ordinary shares held for future awards to employees	--	--	(360)	(360)
Dividends	--	--	1,178	1,178
Investments	(52)	--	(112)	(112)
Additional minimum pension liability	(25)	--	(145)	(145)
Other	--	--	(94)	(54)
BP shareholders' interest as adjusted to accord with US GAAP	57,026	8,951	90,727	41,161

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 47 -- Condensed consolidating information on certain US subsidiaries (continued)

Cash flow statement

	Issuer	Issuer	Guarantor	
	BP America Inc.	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries
			($ million)	
For the year ended December 31, 2001				
Net cash inflow (outflow) from operating activities	306	956	6,199	17,943
Dividends from joint ventures	--	--	--	104
Dividends from associated undertakings	--	--	--	528
Dividends from subsidiaries	925	--	1,537	--
Net cash inflow (outflow) from servicing of finance and returns on investments	(32)	--	1,218	(2,134)
Tax paid	(1,682)	(345)	(1)	(2,632)
Net cash inflow (outflow) for capital expenditure and financial investment	(717)	(1,870)	(33)	(7,229)
Net cash inflow for acquisitions and disposals	--	--	(2,995)	(1,755)
Equity dividends paid	--	--	(4,827)	(2,462)
Net cash inflow (outflow)	(1,200)	(1,259)	1,098	2,363
Financing	(1,198)	(1,262)	1,097	2,335
Management of liquid resources	--	--	--	(211)
Increase in cash	(2)	3	1	239
	(1,200)	(1,259)	1,098	2,363

The consolidated statement of cash flows presented in accordance with SFAS 95 is as follows:

	Issuer	Issuer	Guarantor	
	BP America Inc.	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries
			($ million)	
Net cash provided by (used in) operating activities	(483)	611	8,953	13,809
Net cash provided by (used in) investing activities	(717)	(1,870)	(3,028)	(8,984)
Net cash provided by (used in) financing activities	1,198	1,262	(5,924)	(4,797)
Currency translation differences relating to cash and cash equivalents	--	--	--	(53)

Increase (decrease) in cash and cash equivalents	(2)	3	1	(25)
Cash and cash equivalents at beginning of year	--	(32)	2	1,861
Cash and cash equivalents at end of year	(2)	(29)	3	1,836

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 47 -- Condensed consolidating information on certain US subsidiaries (continued)

Cash flow statement (continued)

	Issuer	Issuer	Guarantor	
	BP America Inc.	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries
			($ million)	
For the year ended December 31, 2000				
Net cash inflow (outflow) from operating activities	(460)	1,683	(12,830)	8,418
Dividends from joint ventures	--	--	--	645
Dividends from associated undertakings	--	--	--	394
Dividends from subsidiaries	899	--	793	--
Net cash inflow (outflow) from servicing of finance and returns on investments	(216)	(1)	431	(1,106)
Tax paid	(397)	(754)	5	(5,052)
Net cash inflow (outflow) for capital expenditure and financial investment	--	(552)	(64)	(6,456)
Net cash inflow for acquisitions and disposals	12	45	18,118	6,295
Equity dividends paid	--	--	(4,415)	(1,692)
Net cash inflow (outflow)	(162)	421	2,038	1,446
Financing	(95)	435	2,039	1,034
Management of liquid resources	--	--	--	452
Increase in cash	(67)	(14)	(1)	(40)
	(162)	421	2,038	1,446

The consolidated statement of cash flows presented in accordance with SFAS 95 is as follows:

	Issuer	Issuer	Guarantor	
	BP America Inc.	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries
			($ million)	
Net cash provided by (used in) operating activities	(174)	928	(11,601)	3,395
Net cash provided by (used in) investing activities	11	(507)	18,054	(161)
Net cash provided by (used in) financing activities	96	(435)	(6,454)	(2,726)
Currency translation differences relating to cash and cash equivalents	--	--	--	(50)
Increase (decrease) in cash and cash equivalents	(67)	(14)	(1)	458
Cash and cash equivalents at beginning of year	67	(18)	3	1,403
Cash and cash equivalents at end of year	--	(32)	2	1,861

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 47 -- Condensed consolidating information on certain US subsidiaries (concluded)

Cash flow statement (concluded)

	Issuer	Issuer	Guarantor	
	BP America Inc.	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries
			($ million)	
For the year ended December 31, 1999				
Net cash inflow from operating activities	10	739	282	10,468
Dividends from joint ventures	--	--	--	949
Dividends from associated undertakings	--	--	--	219
Dividends from subsidiaries	--	--	4,577	--
Net cash inflow (outflow) from servicing of finance and returns on investments	(375)	--	438	(1,066)
Tax paid	124	(62)	(119)	(1,203)

Net cash inflow (outflow) for capital expenditure and financial investment......	--	(393)	(77)	(4,915)
Net cash inflow (outflow) for acquisitions and disposals................	11	1	(1,209)	231
Equity dividends paid......................	--	--	(4,135)	(4,577)
Net cash inflow (outflow)..................	(230)	285	(243)	106
Financing..................................	(298)	273	(245)	(684)
Management of liquid resources.............	--	--	--	(93)
Increase in cash...........................	68	12	2	883
	(230)	285	(243)	106

The consolidated statement of cash flows presented in accordance with SFAS 95 is as follows:

	Issuer	Issuer	Guarantor	
	BP America Inc.	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries
			($ million)	
Net cash provided by (used in) operating activities......................	(240)	677	5,178	9,141
Net cash provided by (used in) investing activities......................	10	(392)	(1,286)	(4,684)
Net cash provided by (used in) financing activities......................	298	(273)	(3,890)	(3,893)
Currency translation differences relating to cash and cash equivalents...............	--	--	--	15
Increase (decrease) in cash and cash equivalents..........................	68	12	2	579
Cash and cash equivalents at beginning of year......................	(1)	(30)	1	824
Cash and cash equivalents at end of year............................	67	(18)	3	1,403

SUPPLEMENTARY OIL AND GAS INFORMATION
(Unaudited)

The following tables show estimates of the Group's net proved reserves of crude oil and natural gas at December 31, 2001, 2000 and 1999.

Estimated net proved reserves of crude oil (a)

	UK	Rest of Europe	USA	Rest of World	Total
			(millions of barrels)		
2001					
Subsidiary undertakings					
At January 1					
Developed	1,138	213	2,150	817	4,318
Undeveloped	254	160	1,043	733	2,190
	1,392	373	3,193	1,550	6,508
Changes in year attributable to:					
Revisions of previous estimates	(16)	16	(39)	(58)	(97)
Purchases of reserves-in-place	9	--	--	11	20
Extensions, discoveries and other additions	94	--	641	552	1,287
Improved recovery	24	29	48	12	113
Production	(177)	(37)	(243)	(144)	(601)
Sales of reserves-in-place	(1)	--	(11)	(1)	(13)
	(67)	8	396	372	709
At December 31					
Developed	1,008	269	2,195	836	4,308
Undeveloped	317	112	1,394	1,086	2,909
	1,325	381	3,589(b)	1,922	7,217

Equity-accounted entities
BP share

At January 1	1,135
Net revisions and other additions	100
Production	(76)
At December 31	1,159
Total Group and BP share of equity-accounted entities	8,376

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)
(Unaudited)

Estimated net proved reserves of crude oil (a) (continued)

	UK	Rest of Europe	USA	Rest of World	Total
			(millions of barrels)		
2000					
Subsidiary undertakings					
At January 1					
Developed	1,158	190	2,930	550	4,828
Undeveloped	183	95	932	497	1,707
	1,341	285	3,862	1,047	6,535
Changes in year attributable to:					
Revisions of previous estimates	17	50	40	5	112
Purchases of reserves-in-place	146	--	554	441	1,141
Extensions, discoveries and other additions	1	--	255	201	457
Improved recovery	131	71	105	22	329
Production	(195)	(33)	(251)	(143)	(622)
Sales of reserves-in-place	(49)	--	(1,372)	(23)	(1,444)
	51	88	(669)	503	(27)
At December 31					
Developed	1,138	213	2,150	817	4,318
Undeveloped	254	160	1,043	733	2,190
	1,392	373	3,193(b)	1,550	6,508

Equity-accounted entities	
BP share	
At January 1	1,037
Net revisions and other additions	93
Purchases of reserves-in-place	73
Production	(68)
At December 31	1,135
Total Group and BP share of equity-accounted entities	7,643

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)
(Unaudited)

Estimated net proved reserves of crude oil (a) (concluded)

	UK	Rest of Europe	USA	Rest of World	Total
			(millions of barrels)		
1999					
Subsidiary undertakings					
At January 1					
Developed	1,258	220	2,982	858	5,318
Undeveloped	270	51	979	686	1,986
	1,528	271	3,961	1,544	7,304
Changes in year attributable to:					
Revisions of previous estimates	(10)	12	11	1	14
Purchases of reserves-in-place	6	--	4	--	10
Extensions, discoveries and other additions	1	24	100	44	169
Improved recovery	28	14	87	83	212
Production	(212)	(36)	(275)	(149)	(672)
Sales of reserves-in-place	--	--	(33)	(476)	(509)
Transfers from equity-accounted entities	--	--	7(d)	--	7
	(187)	14	(99)	(497)	(769)
At December 31					
Developed	1,158	190	2,930	550	4,828
Undeveloped	183	95	932	497	1,707
	1,341	285	3,862(b)(c)	1,047	6,535

Equity-accounted entities
BP share

At January 1	1,128
Net revisions and other additions	(21)
Production	(63)
Transfers to subsidiary undertakings	(7)(d)
At December 31	1,037
Total Group and BP share of equity-accounted entities	7,572

(a) Crude oil includes natural gas liquids and condensate. Net proved reserves of crude oil exclude production royalties due to others.

(b) Proved reserves in the Prudhoe Bay field in Alaska include an estimated 43 million barrels (91 million barrels at December 31, 2000 and 94 million barrels at December 31, 1999) upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

(c) The Group's common interest in Altura Energy was sold in 2000. The minority interest in Altura Energy included 309 million barrels at December 31, 1999.

Equity-accounted entities

(d) Transfer from equity-accounted entities to subsidiary undertakings comprise reserves in Crescendo Resources after the acquisition of the majority interest from Repsol-YPF.

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)
(Unaudited)

Estimated net proved reserves of natural gas (a)

	UK	Rest of Europe	USA	Rest of World	Total
		billions of cubic feet)			
2001					
Subsidiary undertakings					
At January 1					
Developed...........................	3,898	275	12,111	7,985	24,269
Undeveloped.........................	1,058	71	2,400	13,302	16,831
	4,956	346	14,511	21,287	41,100
Changes in year attributable to:					
Revisions of previous estimates......	(25)	(10)	16	(707)	(726)
Purchases of reserves-in-place.......	14	--	2	102	118
Extensions, discoveries and other additions..................	70	15	620	3,748	4,453
Improved recovery..................	136	11	988	132	1,267
Production.........................	(625)	(54)	(1,358)(b)	(1,050)	(3,087)
Sales of reserves-in-place..........	(154)	--	(12)	--	(166)
	(584)	(38)	256	2,225	1,859
At December 31					
Developed...........................	3,212	265	12,232	8,040	23,749
Undeveloped.........................	1,160	43	2,535	15,472	19,210
	4,372	308	14,767	23,512	42,959

Equity-accounted entities
BP share

At January 1..	2,818
Net revisions and other additions..	523
Production..	(125)

At December 31	3,216
Total Group and BP share of equity-accounted entities	46,175

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)
(Unaudited)

Estimated net proved reserves of natural gas (a) (continued)

	UK	Rest of Europe	USA	Rest of World	Total
			billions of cubic feet)		
2000					
Subsidiary undertakings					
At January 1					
Developed	3,354	282	10,439	6,423	20,498
Undeveloped	919	63	1,552	10,770	13,304
	4,273	345	11,991	17,193	33,802
Changes in year attributable to:					
Revisions of previous estimates	(17)	23	150	331	487
Purchases of reserves-in-place	1,099	--	3,034	2,313	6,446
Extensions, discoveries and other additions	253	--	923	2,343	3,519
Improved recovery	29	28	980	91	1,128
Production	(605)	(50)	(1,174)(b)	(916)	(2,745)
Sales of reserves-in-place	(76)	--	(1,393)	(68)	(1,537)
	683	1	2,520	4,094	7,298
At December 31					
Developed	3,898	275	12,111	7,985	24,269
Undeveloped	1,058	71	2,400	13,302	16,831
	4,956	346	14,511	21,287	41,100

Equity-accounted entities
BP share

At January 1	1,724
Net revisions and other additions	427
Purchases of reserves-in-place	763
Production	(96)
At December 31	2,818

Total Group and BP share of equity-accounted entities	43,918

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)
(Unaudited)

Estimated net proved reserves of natural gas (a) (concluded)

	UK	Rest of Europe	USA	Rest of World	Total
	billions of cubic feet)				
1999					
Subsidiary undertakings					
At January 1					
Developed	3,536	324	9,637	6,054	19,551
Undeveloped	1,107	38	1,658	8,647	11,450
	4,643	362	11,295	14,701	31,001
Changes in year attributable to:					
Revisions of previous estimates	1	9	215	(107)	118
Purchases of reserves-in-place	3	--	--	12	15
Extensions, discoveries and other additions	79	34	417	3,296	3,826
Improved recovery	22	--	242	299	563
Production	(475)	(60)	(907)(b)	(752)	(2,194)
Sales of reserves-in-place	--	--	(143)	(256)	(399)
Transfers from equity-accounted entities	--	--	872(d)	--	872
	(370)	(17)	696	2,492	2,801
At December 31					
Developed	3,354	282	10,439	6,423	20,498
Undeveloped	919	63	1,552	10,770	13,304
	4,273	345	11,991(c)	17,193	33,802

Equity-accounted entities
BP share

At January 1	1,766
Net revisions and other additions	549
Purchases of reserves-in-place	378
Production	(97)
Transfers to subsidiary undertakings	(872)(d)

At December 31	1,724
Total Group and BP share of equity-accounted entities	35,526

(a) Net proved reserves of natural gas exclude production royalties due to others.

(b) Includes 61 billion cubic feet of natural gas consumed in Alaskan operations (2000, 55 billion cubic feet and 1999, 77 billion cubic feet).

(c) The Group's common interest in Altura Energy was sold in 2000. The minority interest in Altura Energy included 155 billion cubic feet of natural gas at December 31, 1999.

Equity-accounted entities

(d) Transfers from equity-accounted entities to subsidiary undertakings comprise reserves in Crescendo Resources after the acquisition of the majority interest from Repsol-YPF.

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)
(Unaudited)

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves

The following tables set out the standardized measures of discounted future net cash flows, and changes therein, relating to crude oil and natural gas production from the Group's estimated proved reserves. This information is prepared in compliance with the requirements of FASB Statement of Financial Accounting Standards No. 69 -- 'Disclosures about Oil and Gas Producing Activities'.

Future net cash flows have been prepared on the basis of certain assumptions which may or may not be realized. These include the timing of future production, the estimation of crude oil and natural gas reserves and the application of year end crude oil and natural gas prices and exchange rates. Furthermore, both reserve estimates and production forecasts are subject to revision as further technical information becomes available and economic conditions change. BP cautions against relying on the information presented because of the highly arbitrary nature of assumptions on which it is based and its lack of comparability with the historical cost information presented in the financial statements.

	UK	Rest of Europe	USA	Rest of World	Total
			($ million)		

At December 31, 2001					
Future cash inflows (a)	40,600	8,000	83,700	81,400	213,700
Future production and development costs (b)	18,800	3,500	33,700	30,600	86,600
Future taxation (c)	5,700	3,000	16,900	18,900	44,500
Future net cash flows	16,100	1,500	33,100	31,900	82,600
10% annual discount (d)	5,300	400	16,600	15,800	38,100
Standardized measure of discounted future net cash flows	10,800	1,100	16,500	16,100	44,500
At December 31, 2000					
Future cash inflows (a)	43,800	9,400	187,200	94,100	334,500
Future production and development costs (b)	19,000	2,800	38,400	27,300	87,500
Future taxation (c)	7,100	4,700	45,600	27,100	84,500
Future net cash flows	17,700	1,900	103,200	39,700	162,500
10% annual discount (d)	5,000	700	49,200	18,000	72,900
Standardized measure of discounted future net cash flows	12,700	1,200	54,000	21,700	89,600
At December 31, 1999					
Future cash inflows (a)	42,400	7,900	101,500	49,500	201,300
Future production and development costs (b)	18,800	2,000	32,500	13,700	67,000
Future taxation (c)	5,900	4,200	23,300	15,800	49,200
Future net cash flows	17,700	1,700	45,700	20,000	85,100
10% annual discount (d)	4,700	400	23,200	8,400	36,700
Standardized measure of discounted future net cash flows	13,000	1,300	22,500	11,600	48,400

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)
(Unaudited)

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves (concluded)

The following are the principal sources of change in the standardized measure of discounted future net cash flows during the years ended December 31, 2001, 2000 and 1999:

	Years ended December 31,		
	2001	2000	1999
	($ million)		
Sales and transfers of oil and gas produced, net of			

production costs....................................	(17,500)	(18,400)	(12,600)
Development costs incurred during the year.............	6,800	4,500	2,900
Extensions, discoveries and improved recovery, less related costs..................................	9,200	13,100	6,200
Net changes in prices and production costs (e)..........	(74,100)	51,100	47,900
Revisions of previous reserve estimates.................	(1,300)	900	2,600
Net change in taxation.................................	26,300	(14,800)	(18,000)
Future development costs...............................	(3,200)	(2,400)	(200)
Net change in purchase and sales of reserves-in-place...	(200)	2,400	(900)
Addition of 10% annual discount........................	8,900	4,800	1,900
Total change in the standardized measure during the year	(45,100)	41,200	29,800

(a) Future cash inflows are computed by applying year-end oil and natural gas prices and exchange rates to future annual production levels estimated by the Group's petroleum engineers.

(b) Production costs (which include petroleum revenue tax in the UK) and development costs relating to future production of proved reserves are based on year-end cost levels and assume continuation of existing economic conditions. Future decommissioning costs are included.

(c) Taxation is computed using appropriate year-end income tax rates.

(d) Future net cash flows from oil and natural gas production are discounted at 10% regardless of the Group assessment of the risk associated with its producing activities.

(e) Net changes in prices and production costs includes the effect of exchange movements.

Equity-accounted entities

In addition, at December 31, 2001 the Group's share of the standardized measure of discounted future net cash flows of equity-accounted entities amounted to $3,400 million ($3,100 million at December 31, 2000 and $2,420 million at December 31, 1999).

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)
(Unaudited)

Operational and statistical information

The following tables present operational and statistical information related to production, drilling, productive wells and acreage.

Produced from own reserves

The following table shows crude oil and natural gas production from the Group's own reserves for the years indicated:

	UK	Rest of Europe	USA	Rest of World	Total(d
			(thousand barrels per day)		
Production for the year (a)					
Crude oil (b)					
2001	485	100	744	602	1,931
2000	534	90	729	575	1,928
1999	580	100	804	577	2,061

	UK	Rest of Europe	USA	Rest of World	Total(e
			(million cubic feet per day)		
Natural gas (c)					
2001	1,713	147	3,554	3,218	8,632
2000	1,652	136	3,054	2,767	7,609
1999	1,301	164	2,369	2,233	6,067

(a) All volumes are net of royalty.

(b) Crude oil includes natural gas liquid and condensate.

(c) Natural gas production excludes gas consumed in operations.

(d) Includes amounts produced for the Group by equity-accounted entities of 208,000 b/d in 2001 (2000, 185,000 b/d and 1999, 170,000 b/d).

(e) Includes amounts produced for the Group by equity-accounted entities of 345 mmcf/d in 2001 (2000, 263 mmcf/d and 1999, 264 mmcf/d).

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)
(Unaudited)

Operational and statistical information (continued)

Productive oil and gas wells and acreage

The following tables show the number of gross and net productive oil and natural gas wells and total gross and net developed and undeveloped oil and natural gas acreage in which the Group and its equity-accounted entities had interests as of December 31, 2001. A 'gross' well or acre is one in which a whole or fractional working interest is owned, while the number of 'net' wells or acres is the sum of the whole or fractional working interests in gross wells or acres. Productive wells are producing wells and wells capable of production. Developed acreage is the acreage within the boundary of a field, on which development wells have been drilled, which could produce the reserves; while undeveloped acres are those on which wells have not been drilled or completed to a point that would permit the production of commercial quantities, whether or not such acres contain proved reserves.

Number of productive oil and gas wells

	UK	Rest of Europe	USA	Rest of World	Total
At December 31, 2001					
Oil wells (a) -- gross	457	77	7,804	11,085	19,423
-- net	229.4	28.0	4,565.9	2,942.9	7,766.2
Gas wells (b) -- gross	540	39	19,995	2,829	23,403
-- net	218.4	13.4	11,734.1	1,568.1	13,534.0

(a) Includes approximately 2,045 gross (924.8 net) multiple completion wells (more than one formation producing into the same well bore).

(b) Includes 2,081 gross (1,210.8 net) multiple completion wells.

(c) If one of the multiple completions in a well is an oil completion, the well is classified as an oil well.

Oil and natural gas acreage

	UK	Rest of Europe	USA	Rest of World	Total
			(thousands of acres)		
At December 31, 2001					
Developed					
-- gross	767	133	13,471	6,927	21,298
-- net	341.7	45.3	5,782.4	2,145.0	8,314.4
Undeveloped (a)					
-- gross	4,708	3,975	10,330	99,509	118,522
-- net	2,330.7	1,435.7	5,690.9	42,336.7	51,794.0

(a) Undeveloped acreage includes leases and concessions.

SUPPLEMENTARY OIL AND GAS INFORMATION (Concluded)
(Unaudited)

Operational and statistical information (concluded)

Net oil and gas wells completed or abandoned

The following table shows the number of net productive and dry exploratory and development oil and natural gas wells completed or abandoned in the years indicated by the Group and its equity-accounted entities. Productive wells include wells in which hydrocarbons were encountered and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well is one found to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	UK	Rest of Europe	USA	Rest of World	Total
2001					
Exploratory					
-- productive	3.2	0.9	5.7	18.7	28.5
-- dry	1.2	0.7	3.8	2.5	8.2
Development					
-- productive	13.5	4.2	705.3	325.2	1,048.2
-- dry	1.6	--	25.7	33.5	60.8
2000					
Exploratory					
-- productive	2.4	0.4	21.5	19.9	44.2
-- dry	--	1.3	12.4	7.2	20.9
Development					
-- productive	12.6	2.5	398.4	425.2	838.7
-- dry	1.9	--	45.7	23.4	71.0
1999					
Exploratory					
-- productive	0.5	0.5	3.7	10.1	14.8
-- dry	1.1	0.9	1.4	6.6	10.0
Development					
-- productive	27.3	1.3	274.4	160.6	463.6
-- dry	1.7	0.3	10.5	15.4	27.9

Drilling and production activities in progress

The following table shows the number of exploratory and development oil and natural gas wells in the process of being drilled by the Group and its equity-accounted entities as of December 31, 2001. Suspended development wells and long-term suspended exploratory wells are also included in the table.

	UK	Rest of Europe	USA	Rest of World	Total
At December 31, 2001					
Exploratory					
-- gross	--	3	9	20	32
-- net	--	0.8	3.5	7.2	11.5
Development					
-- gross	20	3	78	95	196
-- net	9.7	0.8	43.2	20.7	74.4

SCHEDULE II

VALUATION AND QUALIFYING ACCOUNTS

	Balance at January 1,	Additions: Charged to costs and expenses	Additions: Charged to other accounts(a)	Transfers/ Deductions	Balanc December
	($ million)				
2001					
Fixed assets -- Investments (b)	505	68	(4)	63	63
Doubtful debts (b)...........	357	131	17	(215)	29
Decommissioning provisions....	3,001	156	353	(206)	3,30
2000					
Fixed assets -- Investments (b)	309	252	(6)	(50)	50
Doubtful debts (b)...........	117	99	117	24	35
Decommissioning provisions....	2,785	139	(23)	100(c)	3,00
1999					
Fixed assets -- Investments (b)	230	83	(2)	(2)	30
Doubtful debts (b)...........	126	12	(13)	(8)	11
Decommissioning provisions....	3,310	80	(472)	(133)	2,78

(a) Principally currency translations, apart from 1999 for decommissioning provisions which includes the impact of adopting FRS 12. For decommissioning provisions this also includes unwinding of discount and the effect of any change in discount rate.

(b) Deducted in the balance sheet from the assets to which they apply.

(c) Includes $484 million additional provisions in respect of acquisitions.