BP PLC
Form 20-F/A
June 13, 2006

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 20-F/A
Amendment No. 1

(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, 2004

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

OR

[ ] SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

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)

1 St James's Square
London
SW1Y 4PD
United Kingdom

(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	**21,525,977,902**
Cumulative First Preference Shares of £1 each	**7,232,838**
Cumulative Second Preference Shares of £1 each	**5,473,414**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes X No ___

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934.

Yes ___ No X

Note Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 from their obligations under those Sections.

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 whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act (Check one):

Large accelerated filer X Accelerated filer ___ Non-accelerated filer ___

Indicate by check mark which financial statement item the Registrant has elected to follow.

Item 17 ___ Item 18 X

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ___ No X

EXPLANATORY NOTE

Introduction

This Amendment No. 1 (Amendment No. 1) to the Annual Report on Form 20-F for the year ended December 31, 2004, as filed with the U.S. Securities and Exchange Commission (the SEC) on June 30, 2005, (the Original Form 20-F), amends portions of the Original Form 20-F to give effect to the Revenues and Cost of Sales Restatement (as defined below) by the registrant as described in further detail below. Except as otherwise stated in this Amendment No. 1, and except as set forth in the Financial Statements with respect to information presented therein, all information presented in this Amendment No. 1, including forward looking statements, is as at June 30, 2005 and has not been updated for events subsequent to the date of the original filing. Certain disclosures are expressly presented as of an earlier date in accordance with disclosure requirements applicable to Form 20-F.

This Amendment No.1 amends and restates in part Items 3, 4, 5, 15, 18 and 19 of the Original Form 20-F, and no other information included in the Original Form 20-F is amended hereby.

This Amendment No. 1 does not amend the registrants' Annual Reports on Form 20-F filed with the SEC for the year ended December 31, 2003 or any prior period.

Revenues and Cost of Sales Restatement

Previously, under US GAAP, revenues associated with over-the-counter forward contracts in oil, gas, NGLs and power were presented on a gross basis under the provisions of EITF 99-19. During 2005, a review was undertaken into the presentation of these transactions. It was concluded that the provisions of EITF 02-03 should have been applied rather than the provisions of EITF 99-19, and the transactions reported on a net basis. Under the provisions of APB 20, management concluded that this change represented an accounting error. Revenue and cost of sales on a US GAAP basis for all periods presented have been restated to adjust for transactions which should be reported net. This restatement, while reducing revenue and cost of sales did not impact the Group's profit for the year as adjusted to accord with US GAAP, profit per ordinary share, cash flow or financial condition.

The following table sets forth the adjustments made to reported US GAAP revenues, cost of sales and profit for the year.

	2004	2003	2002	2001	2000
			($ million)		
Revenues	(81,756)	(58,956)	(32,730)	(28,316)	(16,395)
Cost of sales	(81,756)	(58,956)	(32,730)	(28,316)	(16,395)
Profit for the year					

Refer to Note 50(s) on page F-120 for additional information on the Revenues and Cost of Sales Restatement.

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CERTAIN DEFINITIONS

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

Oil and natural gas reserves

'Proved oil and gas reserves' Proved reserves are defined by the Securities and Exchange Commission (SEC) in Rule 4-10(a) of Regulation S-X, paragraphs (2), (2i), (2ii) and (2iii). 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, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes: (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the 'proved' classification when successful testing by a pilot project, or the operation of an installed programme in the reservoir, provides support for the engineering analysis on which the project or programme was based.

(iii) Estimates of proved reserves do not include the following:

(a) oil that may become available from known reservoirs but is classified separately as 'indicated additional reserves';

(b) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

(c) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

(d) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

'Proved developed reserves' Proved 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 the 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' Proved 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.

'Atlantic Richfield' 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.

'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.

'Liquids' Crude oil, condensate and natural gas liquids.

'Dollar' or '$' The US dollar.

'FSA' Financial Services Authority.

'Gas' Natural Gas.

'Hydrocarbons' Crude oil and natural gas.

'IFRS' International Financial Reporting Standards.

'Joint venture or JV' an entity in which the Group has a long-term interest and shares control with one or more co-venturers.

'LNG' Liquefied Natural Gas.

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

'LPG' Liquefied Petroleum Gas.

'mmbtu' million British thermal units.

'MTBE' Methyl Tertiary Butyl Ether.

'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.

'OECD' Organization for Economic Cooperation and Development.

'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 sterling.

'Pound', 'sterling' or '£' The pound sterling.

'Preference Shares' Cumulative First Preference Shares and Cumulative Second Preference Shares in BP p.l.c. of £1 each.

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

'Tonne' 2,204.6 pounds.

'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.

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. The financial information for 2002 and 2003 has been restated to reflect the adoption by the Group of Financial Reporting Standard No. 17 'Retirement Benefits' (FRS 17) with effect from January 1, 2004. The financial information for 2000 and 2001 has not been restated for FRS 17. The financial information for 2000 to 2003 has been restated to reflect the adoption by the Group of Urgent Issues Task Force Abstract No. 38 'Accounting for Employee Share Ownership Plan (ESOP) Trusts with effect from January 1, 2004.

	Years ended December 31,				
	2004	**2003**	**2002**	**2001**	**2000**
	($ million except per share amounts)				
UK GAAP					
Income statement data					
Turnover	294,849	236,045	180,186	175,389	161,826
Less: joint ventures	9,790	3,474	1,465	1,171	13,764
Group turnover	285,059	232,571	178,721	174,218	148,062
Cost of sales	247,110	201,335	154,615	148,893	120,298
Profit for the year	15,731	10,482	6,795	6,556	10,120
Per ordinary share: (cents)					
Profit for the year:					
Basic	72.08	47.27	30.33	29.21	46.77
Diluted	70.79	46.83	30.19	29.04	46.46
Dividends per share (cents)	29.45	26.00	24.00	22.00	20.50
Dividends per share (pence)	16.099	15.517	15.638	15.436	13.791
Ordinary Share data (a)					
Average number outstanding of 25 cents ordinary shares (shares million undiluted)	21,821	22,171	22,397	22,436	21,638
Average number outstanding of 25 cents ordinary shares (shares million diluted)	22,310	22,429	22,504	22,574	21,783
Balance sheet data					
Total assets	193,213	172,342	155,621	141,704	144,502
Net assets	77,999	71,720	64,472	65,741	66,010
Share capital	5,403	5,552	5,616	5,629	5,653

	Years ended December 31,				
BP shareholders' interest	76,656	70,595	63,834	65,143	65,442
Finance debt due after more than one year	12,907	12,869	11,922	12,327	14,772
Debt to borrowed and invested capital (b)	14%	15%	16%	16%	18%

	Years ended December 31,				
	2004	2003	2002	2001	2000
	($ million except per share amounts)				
US GAAP					
Income statement data					
Revenues (restated) (c)	203,303	173,615	145,991	145,902	131,667
Cost of sales (restated) (c)	165,354	142,379	121,885	120,577	103,903
Profit for the year (c)	17,090	12,941	8,109	4,467	10,164
Comprehensive income	17,364	19,886	10,256	2,952	7,711
Profit per ordinary share: (cents)					
Basic	78.31	58.36	36.20	19.90	46.96
Diluted	76.88	57.79	36.02	19.78	46.65
Profit per American Depositary Share: (cents)					
Basic	469.86	350.16	217.20	119.40	281.76
Diluted	461.28	346.74	216.12	118.68	279.90
Balance sheet data					
Total assets	205,648	186,576	164,103	145,990	151,966
Net assets	86,435	80,292	67,274	62,786	65,655
BP shareholders' interest	85,092	79,167	66,636	62,188	65,087

(a) The number of ordinary shares shown have been used to calculate per share amounts for both UK and US GAAP.

(b) Finance debt due after more than one year, as a percentage of such debt plus BP and minority shareholders' interests.

(c) Previously, under US GAAP, revenues associated with over-the-counter forward contracts in oil, gas, NGLs and power were presented on a gross basis under the provisions of EITF 99-19. During 2005, a review was undertaken into the presentation of these transactions. It was concluded that the provisions of EITF 02-03 should have been applied rather than the provisions of EITF 99-19, and the transactions reported on a net basis. Under the provisions of APB 20, management concluded that this change represented an accounting error. Revenue and cost of sales on a US GAAP basis for all periods presented have been restated to adjust for transactions which should be reported net. While reducing the reported amount of revenues and cost of sales, the restating of these transactions on a net basis did not impact the Group's profit for the year as adjusted to accord with US GAAP, profit per ordinary share, cash flow or financial position.

Further information is shown in Item 18 Financial Statements Note 50 on page F-103.

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 Atlantic Richfield shareholders do not have the right to receive dividends.

BP currently announces dividends for ordinary shares in US dollars and states an equivalent pounds sterling dividend. Dividends on BP ordinary shares will be paid in pounds sterling and on BP ADSs in US dollars. The rate of exchange used to determine the sterling amount equivalent is the average of the forward exchange rate in London over the five business days prior to the announcement date. The directors may choose to declare dividends in any currency provided that a sterling equivalent is announced, but it is not the Company's intention to change its current policy of announcing dividends on ordinary shares in US dollars.

The following table shows dividends announced by the Company per ADS for each of the past five years before the 'refund' and deduction of withholding taxes as described in Item 10 Additional Information Taxation on page 164. 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.

For dividends paid after April 30, 2004, there will be no refund available to shareholders resident in the US. Refer to Item 10 Additional Information Taxation for more information.

Dividends per American Depositary Share		Quarterly First	Second	Third	Fourth	Total
2000	UK pence	19.3	20.1	21.6	21.7	82.7
	US cents	30.0	30.0	31.5	31.5	123.0
	Can. cents	44.7	44.8	48.2	47.9	185.6
2001	UK pence	22.0	23.5	22.8	24.3	92.6
	US cents	31.5	33.0	33.0	34.5	132.0
	Can. cents	48.3	50.4	52.6	54.9	206.2
2002	UK pence	24.3	23.3	23.4	22.9	93.9
	US cents	34.5	36.0	36.0	37.5	144.0
	Can. cents	54.1	56.7	56.1	57.4	224.3
2003	UK pence	23.7	24.2	23.1	22.0	93.0
	US cents	37.5	39.0	39.0	40.5	156.0
	Can. cents	54.3	54.0	51.1	53.7	213.1
2004	UK pence	22.8	23.2	23.5	27.1	96.6
	US cents	40.5	42.6	42.6	51.0	176.7
	Can. cents	54.8	56.7	52.2	64.0	227.7

A dividend reinvestment plan is in place 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.

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 on page 83.

RISK FACTORS

We urge you to carefully consider the risks described below. If any of these risks actually occur, our business, financial condition and results of operations could suffer, and the trading price and liquidity of our securities could decline, in which case you may lose all or part of your investment.

External Risks

There are a number of risks that arise as a result of the business climate, which are not directly controllable.

Competition Risk: The oil, gas and petrochemicals industries are highly competitive. There is strong competition, both within the oil and gas industry and with other industries, in supplying the fuel needs of commerce, industry and the home. Competition puts pressure on product prices, affects oil products marketing and requires continuous management focus on reducing unit costs and improving efficiency.

Price Risk: 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 supply and oil prices. 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 BP 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 BP Group's results of operations in the period in which it occurs.

Regulatory Risks: The oil industry is 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, controls over the development and decommissioning of a field (including restrictions on production) and, possibly, nationalization, expropriation, cancellation or non-renewal 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 and operates in certain tax jurisdictions which have a degree of uncertainty relating to the interpretation of, and changes to, tax law. As a result of new laws and regulations or other factors, we could be required to curtail or cease certain operations, causing our production to decrease, or we could incur additional costs.

Developing Country Risk: We have operations in developing countries where political, economic and social transition is taking place. Some countries have experienced political instability, expropriation or nationalization of property, civil strife, strikes, acts of war and insurrections. Any of these conditions occurring could disrupt or terminate our operations, causing our development activities to be curtailed or terminated in these areas or our production to decline and could cause us to incur additional costs.

Currency Risk: Crude oil prices are generally set in US 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.

Economic Risk - Refining and Petrochemicals Market: Refining profitability can be volatile with both periodic oversupply and supply tightness in various regional markets. Sectors of the chemicals industry are also subject to fluctuations in supply and demand within the petrochemicals market, with consequent effect on prices and profitability.

Reputational Risks

We set ourselves high standards of corporate citizenship and aspire to contribute to a better quality of life through the products and services we provide. This may create risks to our reputation if it is perceived that our actions are not aligned to these standards and aspirations.

Social Responsibility Risk: Risk could arise if it is perceived that we are not respecting or advancing the economic and social progress of the communities in which we operate.

Environmental Risk: We seek to conduct our activities in such a manner that there is no or minimum damage to the environment. Risk could arise if we do not apply our resources to overcome the perceived trade-off between global access to energy and the protection or improvement of the natural environment.

Compliance Risk: Incidents of non-compliance with applicable laws and regulation or ethical misconduct could be damaging to our reputation and shareholder value.

Operational Risks

Inherent in our operations are hazards which require continual oversight and control. If operational risks materialized it could result in loss of life, damage to the environment or loss of production.

Drilling and Production Risk: 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. The cost of drilling, completing or operating wells is often uncertain. We may be required to curtail, delay or cancel drilling operations because of a variety of factors including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, adverse weather conditions and compliance with governmental requirements.

Technical Integrity Risk: There is a risk of loss of containment of hydrocarbons and other hazardous material at operating sites, pipelines or during transportation by road, rail or sea.

Security Risk: Acts of terrorism that threaten our plants and offices, pipelines, transportation or computer systems would severely disrupt business and operations.

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 businesses 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', 'should', 'may', 'is likely to', 'intends', 'believes', 'plans', 'we see' 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 with regard to management aims and objectives, future capital expenditure, future hydrocarbon production volume, date or period(s) in which production is scheduled or expected to come on stream or a project or action is scheduled or expected to be completed, capacity of planned plants or facilities and impact of health, safety and environmental regulations; (ii) the statements in Item 4 Information on the Company with regard to planned expansion, investment or other projects and future regulatory actions; and (iii) the statements in Item 5 Operating and Financial Review with regard to the plans of the Group, cash flows, opportunities for material acquisitions, the cost of future remediation programmes, liquidity and costs for providing pension and other postretirement benefits; and including under 'Liquidity and Capital Resources' with regard to future cash flows, future levels of capital expenditure and divestments, working capital, the renewal of borrowing facilities, shareholder distributions and share buybacks and expected payments under contractual and commercial commitments; under 'Outlook' with regard to global and certain regional economies, oil and gas prices and realizations, expectations for supply and demand, refining and marketing margins; 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 or may 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; the timing of bringing new fields on stream; future levels of industry product supply, demand and pricing; operational problems; general economic conditions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations; exchange rate fluctuations; development and use of new technology; the success or otherwise of partnering; the actions of competitors; natural disasters and adverse weather conditions; changes in public expectations and other changes to business conditions; wars and acts of terrorism or sabotage; and other factors discussed elsewhere in this report including under 'Risk Factors' above. 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, including 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, incorporated in Indiana, USA, in 1889, and The British Petroleum Company p.l.c., registered in 1909 in England and Wales. The resulting company, BP p.l.c., is a public limited company, registered in England and Wales.

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.
1 St James's Square
London SW1Y 4PD
United Kingdom
Tel: +44(0)20 7496 4000
Internet address: www.bp.com

Our agent in the USA is:

BP America Inc.
4101 Winfield Road
Warrenville, Illinois 60555
Tel: +1 630 821 2222

Overview of the Group

For years to December 31, 2004, our operating business segments were Exploration and Production; Refining and Marketing; Petrochemicals; and Gas, Power and Renewables. 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). The activities of Refining and Marketing include oil supply and trading as well as refining and marketing (downstream activities). Petrochemicals activities include manufacturing, marketing and distribution. The Petrochemicals segment ceased to report separately as from January 1, 2005 (see Resegmentation in 2005 in this Item on page 17). Gas, Power and Renewables activities include marketing and trading of natural gas, NGL, new market development and LNG, and solar and renewables. The Group provides high quality technological support for all its businesses through its research and engineering activities.

These segments fall into two groupings: the Resources Business comprising Exploration and Production; and Customer Facing Businesses comprising Refining and Marketing, Petrochemicals and Gas, Power and Renewables.

The Group's operating business segments are managed on a global basis and not on a regional basis. Geographical information for the Group and segments is given to provide additional information for investors, but does not reflect the way BP manages its activities. Information by geographical area is provided for production and reserves in response to the requirements of Appendix A to Item 4D of Form 20-F.

We have well established operations in Europe, the USA, Canada, South America, Australasia and parts of Africa. Currently, more than 70% of the Group's capital is invested in Organization for Economic Cooperation and Development (OECD) countries with just under 40% of our fixed assets located in the USA, and around 30% located in the UK and the Rest of Europe.

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

In Exploration and Production, we have upstream interests in 26 countries. In addition to our drive to maximize the value of our existing portfolio we are continuing to develop new profit centres. Exploration and Production activities are managed through operating units which are accountable for the day-to-day management of the segment's activities. An operating unit is accountable for one or more fields. Profit centres comprise one or more operating units. Profit centres are, or are expected to become, areas that provide significant production and income for the segment. Our new profit centres are in Asia Pacific, (Australia, Vietnam, Indonesia and China), Azerbaijan, North Africa (Algeria), Angola, Trinidad, Deepwater Gulf of Mexico and Russia, where we believe we have competitive advantage and which we believe provide the foundation for volume growth and improved margins in the future. We also have significant midstream activities to support our upstream interests.

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 2002 by acquiring Veba Oil (Veba). The Veba transaction expanded our refining position in Germany and our marketing position in Germany and Central Europe. Veba markets gasoline under the Aral brand, which is now our principal retail brand in Germany and in the Czech Republic. We have established or are growing businesses elsewhere in the world under the BP brand.

In Petrochemicals, we are a significant producer with strong manufacturing and marketing bases in the USA and Europe. We are growing in the Asia Pacific region, where we already have interests in a number of production facilities. Our strategy is focused on seven core products, with the aim of providing world-class performance in all aspects of our activities. We are now managing our portfolio in two distinct parts Aromatics and Acetyls (A&A), comprising purified terephthalic acid (PTA), paraxylene (PX) and acetic acid, and Olefins and Derivatives (O&D) comprising principally ethylene and related co-products, polypropylene, high density polyethylene (HDPE) and acrylonitrile (see Resegmentation in 2005 in this Item on page 17).

In Gas, Power and Renewables, we have growing marketing and trading businesses in North America (USA and Canada), the UK and the rest of Europe. Our marketing and trading activities include natural gas, LNG, NGL and power. Our international natural gas monetization activities, which are our efforts to identify and capture worldwide opportunities to sell our upstream natural gas resources, are focused on growing natural 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, Spain and South Korea.

Acquisitions and Disposals

With effect from February 1, 2002, BP acquired a majority stake in Veba from E.ON. Veba owned Aral, which was Germany's biggest fuels retailer. BP paid E.ON $1.1 billion in cash and assumed some $1.5 billion of debt in return for 51% and operational control of Veba. Under the terms of the agreement, E.ON had the option to require BP to buy the remaining 49% of Veba.

On June 30, 2002, BP purchased the remaining 49% of Veba from E.ON for $2.4 billion. Separately, E.ON acquired BP's wholly-owned subsidiary Gelsenberg, which held a 25.5% stake in Germany's largest natural gas distributor, Ruhrgas, for $2.3 billion.

As a condition of regulatory approval of the deal, BP was 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. During 2003, BP fully complied with the conditions imposed.

Separately, BP and E.ON sold the bulk of Veba's oil and natural gas exploration and production business to Petro-Canada for $1.6 billion in the second quarter of 2002.

In addition to the sale of Veba's exploration and production business, 2002 disposal proceeds of $6,782 million included $2,338 million from the sale of our investment in Ruhrgas, with the balance of the proceeds coming from a number of other transactions.

In August 2003, BP and Alfa Group and Access-Renova (AAR) completed a transaction first announced in February 2003 to create the third largest oil company operating in Russia based on production volume. The company, TNK-BP, is a 50:50 joint venture between BP and AAR, and operates in Russia and the Ukraine. BP's share of the result of the TNK-BP joint venture has been included within the Exploration and Production segment from August 29, 2003.

AAR contributed its holdings in TNK and Sidanco, its share of Rusia Petroleum, its stake in the Rospan gasfield in West Siberia and its interest in the Sakhalin IV and V exploration licence to the joint venture. BP contributed its holding in Sidanco, its stake in Rusia Petroleum and its holding in the BP Moscow retail network. Neither AAR's association with Slavneft, nor BP's interest in LukArco or the Russian elements of BP's international businesses such as lubricants, marine and aviation were included in this transaction.

In addition, BP paid AAR $2.6 billion in cash upon completion of the transaction, which was subsequently reduced by receipt of pre-acquisition dividends net of transaction costs of $0.3 billion, and subject to the terms of its agreement with AAR, will pay three annual tranches of $1.25 billion in BP shares, valued at market prices prior to each annual payment. In September 2004, the first of the three annual tranches was paid to AAR in BP ordinary shares.

In January 2004, BP and AAR completed a subsequent transaction to include AAR's 50% stake in Slavneft within TNK-BP, at which time BP paid $1.35 billion to AAR. Slavneft was previously held equally by AAR and Sibneft.

The shareholder agreement between BP and AAR establishes TNK-BP in the British Virgin Islands with English law principles governing the legal system. The shareholder agreement establishes joint control between AAR and BP. BP holds 50% of the voting rights in TNK-BP. BP and AAR have equal representation on the TNK-BP Board, with AAR nominating the Chairman and Chairman of the Remuneration Committee, and with BP nominating the Vice Chairman and Chairman of the Audit Committee. BP appoints the Chief Executive Officer of TNK-BP and holds half of the senior management positions.

Disposal proceeds in 2003 amounted to $6,432 million, and resulted primarily from the sale of various upstream interests and completion of divestments required as a condition of approval of the Veba acquisition.

On November 2, 2004, Solvay exercised its option to sell its interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America to BP. Solvay held 50% of BP Solvay Polyethylene Europe and 51% of BP Solvay Polyethylene North America. On completion, the two entities, which manufacture and market high density polyethylene, became wholly owned subsidiaries of BP. The total consideration for the acquisition was $1,391 million.

During 2004, BP China and Sinopec announced the establishment of the BP-Sinopec (Zhejiang) Petroleum Co. Ltd., a retail joint venture between BP and Sinopec. Based on the existing service station network of Sinopec, the new 30-year dual branded joint venture has plans to build, operate and manage a network of 500 service stations in Hangzhou, Ningbo and Shaoxing. Also during the year, BP China and PetroChina announced the establishment of BP-PetroChina Petroleum Company Limited. Located in Guangdong, one of the most developed provinces in China, the 30 year dual branded joint venture is intended to acquire, build, operate and manage 500 service stations in the province within three years of establishment. The initial investment in both joint ventures amounted to $106 million.

Disposal proceeds in 2004 were $5,048 million which included $2.3 billion from the sale of the Group's investments in PetroChina and Sinopec. Additionally, it includes proceeds from: the sale of various oil and gas properties, the sale of our interest in Singapore Refining Company Private Limited, the sale of our speciality intermediate chemicals and Fabrics and Fibres businesses and the sale of two natural gas liquids plants.

Resegmentation in 2005

It is our intention to divest the O&D business, possibly starting with an Initial Public Offering in the second half of 2005, subject to market conditions and the receipt of necessary approvals. Additionally, in November 2004, we announced our intention to include the Grangemouth and Lavéra refineries in the new O&D business. In March 2005, we announced the new O&D entity would be called Innovene and would be formed as a separate entity within the Group in April 2005. We intend to retain and grow the A&A businesses.

As a result, with effect from January 1, 2005:

- The Petrochemicals segment ceased to report separately.
- The Grangemouth and Lavéra refineries were transferred from the Refining and Marketing segment to the O&D business.
- A small US operation, the Hobbs fractionator, which supplies petrochemicals feedstock, has been transferred from Gas, Power and Renewables to the O&D business.
- The new O&D entity, Innovene, reports within Other Businesses and Corporate.
- The Aromatics and Acetyls businesses and the Petrochemicals assets that are integrated with our Gelsenkirchen refinery in Germany are now part of Refining and Marketing.

In addition to these changes related to the divestment of the O&D business, the Mardi Gras pipeline system in the Gulf of Mexico has been transferred from Exploration and Production to Refining and Marketing with effect from January 1, 2005.

Financial and Operating Information

The following table summarizes the Group's turnover, profit and capital expenditure for the last five years and total assets at the end of each of those years. The financial information for 2002 and 2003 has been restated to reflect the adoption by the Group of Financial Reporting Standard No. 17 'Retirement Benefits' (FRS 17) with effect from January 1, 2004. The financial information for 2000 and 2001 has not been restated for FRS 17. The financial information for 2000 to 2003 has been restated to reflect the adoption by the Group of Urgent Issues Task Force Abstract No. 38 'Accounting for Employee Share Ownership Plan (ESOP) Trusts with effect from January 1, 2004.

	Years ended December 31,				
	2004	**2003**	**2002**	**2001**	**2000**
Turnover	294,849	236,045	180,186	175,389	161,826
Less: joint ventures	9,790	3,474	1,465	1,171	13,764
Group turnover (sales to third parties)	285,059	232,571	178,721	174,218	148,062
Total operating profit (a)	24,427	17,123	11,161	14,127	18,407
Profit for the year*	15,731	10,482	6,795	6,556	10,120
Capital expenditure and acquisitions (b)	17,249	20,012	19,093	14,091	47,549
Total assets	193,213	172,342	155,621	141,704	144,502

*
After minority shareholders' interest

(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, other finance expense and taxation.

(b)
Capital expenditure and acquisitions for 2004 includes $1,354 million for including TNK's interest in Slavneft within TNK-BP and $1,355 million for the acquisition of Solvay's interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America; for 2003 includes $5,794 million for the acquisition of our interest in TNK-BP; for 2002 includes $5,038 million for the acquisition of Veba; and for 2000 includes $27,506 million for the acquisition of Atlantic Richfield and $8,936 million for other significant one-off cash investments.

With the exception of the Atlantic Richfield acquisition, which was a share transaction, and the shares issued to AAR in connection with TNK-BP (see Acquisitions and Disposals in this Item on page 16) all capital expenditure and acquisitions during the last five years have been financed from cash flow from operations, disposal proceeds and external financing.

Information for 2004, 2003 and 2002 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 49 on page F-99.

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

	Years ended December 31,				
	2004	2003	2002	2001	2000
Crude oil production for subsidiaries (thousand barrels per day)	1,480	1,615	1,766	1,723	1,743
Crude oil production for equity-accounted entities (thousand barrels per day)	1,051	506	252	208	185
Natural gas production for subsidiaries (million cubic feet per day)	7,624	8,092	8,324	8,287	7,346
Natural gas production for equity-accounted entities (million cubic feet per day)	879	521	383	345	263
Estimated net proved crude oil reserves for subsidiaries (million barrels) (a)(b)	6,755	7,214	7,762	7,217	6,508
Estimated net proved crude oil reserves for equity-accounted entities (million barrels) (a)(c)	3,179	2,867	1,403	1,159	1,135
Estimated net proved natural gas reserves for subsidiaries (billion cubic feet) (a)(d)	45,650	45,155	45,844	42,959	41,100
Estimated net proved natural gas reserves for equity-accounted entities (billion cubic feet) (a)(e)	2,857	2,869	2,945	3,216	2,818

(a) Net proved reserves of crude oil and natural gas exclude production royalties due to others, whether royalty is payable in cash or in kind.

(b) Includes 40 million barrels (55 million barrels at December 31, 2003 and 17 million barrels at December 31, 2002) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

(c) Includes 127 million barrels (97 million barrels at December 31, 2003) in respect of the 5.9% minority interest in TNK-BP.

(d) Includes 4,064 billion cubic feet of natural gas (4,505 billion cubic feet at December 31, 2003 and 1,185 billion cubic feet at December 31, 2002) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

(e) Includes 13 billion cubic feet (December 31, 2003 nil) in respect of the 5.9% minority interest in TNK-BP.

During 2004, 796 million barrels of oil and natural gas, on an oil equivalent* basis (mmboe), were added to BP's proved reserves for subsidiaries (excluding purchases and sales). After allowing for production, which amounted to 1,026 mmboe, BP's proved reserves for subsidiaries, were 14,626 mmboe at December 31, 2004. These proved reserves are mainly located in the USA (39%), Rest of Americas (22%) and the UK (10%).

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

For equity-accounted entities, 506 mmboe were added to proved reserves, (excluding purchases and sales), production was 444 mmboe and proved reserves were 3,672 mmboe at December 31, 2004.

SEGMENTAL INFORMATION

The following tables show turnover and profit before interest expense, other finance expense and tax by business and by geographical area, for the years ended December 31, 2004, 2003 and 2002.

	Years ended December 31,								
	2004			2003			2002		
Turnover (a)	**Total sales**	**Sales between businesses**	**Sales to third parties**	**Total sales**	**Sales between businesses**	**Sales to third parties**	**Total sales**	**Sales between businesses**	**Sales to third parties**
	($ million)			($ million)			($ million)		
By business									
Exploration and Production	34,914	24,756	10,158	30,753	22,885	7,868	25,083	18,109	6,974
Refining and Marketing	179,587	6,539	173,048	149,477	4,448	145,029	125,836	3,366	122,470
Petrochemicals	21,209	780	20,429	16,075	592	15,483	13,064	557	12,507
Gas, Power and Renewables	83,320	2,442	80,878	65,639	1,963	63,676	37,580	1,320	36,260
Other businesses and corporate	546		546	515		515	510		510
Group turnover	319,576	34,517	285,059	262,459	29,888	232,571	202,073	23,352	178,721
Share of joint venture sales			9,790			3,474			1,465
			294,849			236,045			180,186

	Total sales	**Sales between areas**	**Sales to third parties**	**Total sales**	**Sales between areas**	**Sales to third parties**	**Total sales**	**Sales between areas**	**Sales to third parties**
	($ million)			($ million)			($ million)		
By geographical area									
UK (b)	81,155	28,484	52,671	54,971	15,275	39,696	48,748	14,673	34,075
Rest of Europe	54,422	6,928	47,494	50,582	8,672	41,910	46,518	7,980	38,538
USA	130,652	3,603	127,049	108,910	2,169	106,741	80,381	2,099	78,282
Rest of World	68,052	10,207	57,845	52,498	8,274	44,224	34,401	6,575	27,826
	334,281	49,222	285,059	266,961	34,390	232,571	210,048	31,327	178,721
Share of joint venture sales									
UK			155			144			129
Rest of Europe			296			290			298
USA			212			177			236

	Years ended December 31,		
Rest of World	9,127	2,863	802
	9,790	3,474	1,465

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

Analysis of profit	Group operating profit (a)	Joint ventures	Associated undertakings	Total operating profit (a)	Exceptional items (b)	Profit before interest and tax
			($ million)			
Year ended December 31, 2004						
By business						
Exploration and Production	15,195	2,948	235	18,378	152	18,530
Refining and Marketing	5,921	31	132	6,084	(117)	5,967
Petrochemicals	(204)	(36)	252	12	(563)	(551)
Gas, Power & Renewables	911		15	926	56	982
Other businesses and corporate	(973)			(973)	1,287	314
	20,850	2,943	634	24,427	815	25,242
By geographical area						
UK (c)	2,402	(3)	9	2,408	(343)	2,065
Rest of Europe	3,130	(7)	34	3,157	(87)	3,070
USA	9,039	29	70	9,138	(205)	8,933
Rest of World	6,279	2,924	521	9,724	1,450	11,174
	20,850	2,943	634	24,427	815	25,242
Year ended December 31, 2003						
By business						
Exploration and Production	12,570	914	272	13,756	913	14,669
Refining and Marketing	2,319	29	135	2,483	(213)	2,270
Petrochemicals	512	(19)	92	585	38	623
Gas, Power & Renewables	585		(3)	582	(6)	576
Other businesses and corporate	(301)		18	(283)	99	(184)
	15,685	924	514	17,123	831	17,954
By geographical area						
UK (c)	1,929	(19)	14	1,924	717	2,641
Rest of Europe	2,259		12	2,271	(151)	2,120
USA	6,566	27	79	6,672	(347)	6,325
Rest of World	4,931	916	409	6,256	612	6,868
	15,685	924	514	17,123	831	17,954
Year ended December 31, 2002						
By business						
Exploration and Production	8,395	343	268	9,006	(726)	8,280
Refining and Marketing	1,765	24	180	1,969	613	2,582
Petrochemicals	457	(20)	10	447	(256)	191
Gas, Power & Renewables	362		107	469	1,551	2,020
Other businesses and corporate	(782)		52	(730)	(14)	(744)
	10,197	347	617	11,161	1,168	12,329
By geographical area						
UK (c)	1,211	(14)	10	1,207	(88)	1,119
Rest of Europe	2,065	(2)	132	2,195	1,817	4,012
USA	3,493	17	136	3,646	(242)	3,404

Analysis of profit	Group operating profit (a)	Joint ventures	Associated undertakings	Total operating profit (a)	Exceptional items (b)	Profit before interest and tax
Rest of World	3,428	346	339	4,113	(319)	3,794
	10,197	347	617	11,161	1,168	12,329

(a)
Group operating profit and total operating profit are before interest expense and other finance 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.

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

EXPLORATION AND PRODUCTION

The activities of our Exploration and Production business include oil and 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 LNG processing facilities the midstream activities. We have Exploration and Production interests in 26 countries. Areas of activity include the USA, UK, Norway, Canada, South America, the Caribbean, Africa, the Middle East and Asia Pacific. Production during 2004 came from 22 countries. Our most significant midstream activities are in three major pipelines the Trans Alaska Pipeline System (TAPS, BP 46.9%); the Forties Pipeline System (FPS, BP 100%) and the Central Area Transmission System pipeline (CATS, BP 29.5%) both in the UK sector of the North Sea; and four major LNG plants the Atlantic LNG plant in Trinidad (BP 34% in Train 1, 42% in Trains 2 and 3, and 37.8% in Train 4); in Indonesia through our interests in Sanga-Sanga Production Sharing Agreement (PSA) (BP 38%), which supplies natural gas to the Bontang LNG plant, and Tangguh (PSA, BP 37%), which is under construction; and in Australia through our share of LNG from the North West Shelf natural gas development (BP 16.7%).

With effect from January 1, 2004, we transferred certain of our Natural Gas Liquid processing plants to the Gas, Power and Renewables segment in order to consolidate the management of our global NGL activity. The 2003 and 2002 data below has been restated to reflect this transfer.

	Years ended December 31,		
	2004	**2003**	**2002**
		($ million)	
Turnover (a)	34,914	30,753	25,083
Total operating profit	18,378	13,756	9,006
Total assets	83,048	77,703	71,423
Capital expenditure and acquisitions	11,193	15,370	9,659
		($ per barrel)	
Average BP crude oil realizations (b)	36.45	28.23	24.06
Average BP NGL realizations (b)	26.75	19.26	12.85
Average BP liquids realizations (b) (c)	35.39	27.25	22.69
Average West Texas Intermediate oil price	41.49	31.06	26.14
Average Brent oil price	38.27	28.83	25.03
		($ per thousand cubic feet)	
Average BP natural gas realizations (b)	3.86	3.39	2.46
Average BP US natural gas realizations (b)	5.11	4.47	2.63
		($ per mmbtu)	
Average Henry Hub gas price (d)	6.13	5.37	3.22

(a) Excludes BP's share of joint venture turnover of $8,734 million in 2004, $2,587 million in 2003 and $539 million in 2002.

(b) The Exploration and Production business does not undertake any hedging activity. Consequently, realizations reflect the market price achieved.

(c) Crude oil and natural gas liquids.

(d)

Henry Hub First of Month Index.

Our upstream activities are divided between existing profit centres that is our operations in Alaska, Egypt, Latin America (including Argentina, Bolivia, Brazil, Colombia, Mexico and Venezuela), Middle East (including Abu Dhabi, Sharjah and Pakistan), North America Gas (Onshore US, the Gulf of Mexico Shelf and Canada) and the North Sea (UK, Netherlands and Norway); and new profit centres that is our operations in Asia Pacific (Australia, Vietnam, Indonesia and China), Azerbaijan, North Africa (Algeria), Angola, Trinidad, Deepwater Gulf of Mexico and Russia.

Operations in Argentina, Bolivia, Abu Dhabi and the TNK-BP operations in Russia are conducted through equity-accounted entities.

The Exploration and Production strategy is to:

- create new profit centres by accessing areas with the potential for large oil and natural gas fields; exploring successfully and pursuing the best projects for development;
- manage the performance of producing assets by investing in the best available opportunities and optimizing operating efficiency; and
- sell assets that are no longer strategic to us and have greater value to others.

This strategy is underpinned by a focus on investing in a portfolio of large, lower-cost oil and natural gas fields chosen for their potentially strong return on capital employed. We seek to manage those assets safely with maximum capital and operating efficiency. We continue to develop new profit centres in which we have a distinctive position. These new profit centres augment the production assets in our existing profit centres, providing greater reach, investment choice and opportunity for growth.

In support of growth, 2004 capital expenditure was $9.8 billion, excluding the $1.4 billion payment to AAR to incorporate its 50% interest in Slavneft into TNK-BP. Excluding $5.8 billion for the purchase of our interest in TNK-BP, 2003 capital expenditure was $9.6 billion versus the 2002 level of $9.2 billion. Including acquisitions, capital expenditure and acquisitions in 2004 was $11.2 billion compared with $15.4 billion in 2003 and $9.7 billion in 2002. Development expenditure incurred in 2004, excluding midstream activities, was $7,271 million compared with $7,535 million in 2003 and $7,224 million in 2002. This reflects the investment we have been making in our new profit centres and the development phase on many of our major projects. Capital expenditure excluding acquisitions for 2005 is planned to be between $9.5 billion and $10 billion.

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 2004 were $1,038 million compared to $826 million in 2003 and $1,108 million in 2002. About 22% of 2004 exploration and appraisal costs were directed towards appraisal activity. In 2004, we participated in 118 gross (56.6 net) exploration and appraisal wells in 13 countries. The principal areas of activity were Angola, Egypt, Russia (outside TNK-BP), Trinidad and the USA.

Total exploration expense in 2004 of $637 million (2003 $542 million, 2002 $644 million) includes the write-off of unsuccessful drilling activity in the Gulf of Mexico ($135 million), in Brazil ($32 million) and in the UK ($13 million).

In 2004, we obtained upstream rights in several new tracts, which include the following:

- In Egypt, BP was awarded two new blocks in the Gulf of Suez and two new blocks in the Nile Delta.
- In the Gulf of Mexico, BP was awarded 76 blocks in the Outer Continental Shelf Lease Sales 190 and 192.

In 2004, we were involved in discoveries in Angola, Egypt, Trinidad, Russia 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 2004 discoveries included the following:

In Angola, BP made further discoveries in the "ultra deep water' (greater than 1,500 metres) acreage with the Venus and Palas wells in Block 31 (BP 26.7% and operator). The Ceres discovery in the same Block, and the Cesio and Chumbo discoveries in Block 18 (BP 50% and operator) were announced in 2005.

In Egypt, BP made three discoveries in the Nile Delta with the Raven well in the North Alexandria Concession (BP 60% and operator), with the Taurt well in the Ras El Barr Concession (BP 50% and operator) and the Polaris well in the West Mediterranean Deepwater Concession (BP 80% and operator).

In Trinidad, BP made a discovery with the Chachalaca well (BP 100%).

In Russia, a discovery was made in the Kaigansky-Vasukansky licence in the south of the Sakhalin V area with the Pela Lache well (BP 49%, operated by Elvary Neftegas, a JV company established by Rosneft and BP).

In the Deepwater Gulf of Mexico, a discovery was made with the Puma well (BP 51.7% and operator) in the Southern Green Canyon.

Reserves and Production

BP manages its hydrocarbon resources in three major categories: prospect inventory; non-proved resources and proved reserves. When a discovery is made, volumes transfer from the prospect inventory to the non-proved resource category. The reserves move through various non-proved resource subcategories as their technical and commercial maturity increases through appraisal activity. Reserves in a field will only be categorized as proved when all the criteria for attribution of proved status have been met including an internally imposed requirement for project sanction, or for sanction expected within six months and, for additional reserves in existing fields, the requirement that the reserves be included in the business plan and scheduled for development within three years. Internal approval and final investment decision are what we refer to as project sanction.

At the point of sanction, all booked reserves will be categorized as proved undeveloped (PUD). Volumes will subsequently be recategorized from PUD to proved developed (PD) as a consequence of development activity. When part of a well's reserves depends on a later phase of activity, only that portion of reserves associated with existing, available facilities and infrastructure moves to PD. The first PD bookings will occur at the point of first oil or gas production. Major development projects typically take one to four years from the time of initial booking to the start of production. Changes to reserves bookings may be made due to analysis of new or existing data concerning production, reservoir performance, commercial factors, acquisition and divestment activity and additional reservoir development activity.

BP has an internal process to control the quality of reserve bookings which forms part of an integrated system of internal control. BP's process to manage reserve bookings has been centrally controlled for over 15 years and it currently has several key elements.

The first element is the accountabilities of certain officers of the Company to ensure that there are effective controls in the proved reserve verification and approval process of the Group's reserve estimates and the timely reporting of the related financial impacts of proved reserve changes. These officers of the Company are responsible for carrying out verification of proved reserve estimates and are independent of the operating business unit to ensure integrity and accuracy of reporting.

The second element is the capital allocation processes whereby delegated authority is exercised to commit to capital projects that are consistent with the delivery of the Group's business plan. A formal review process exists to ensure that both technical and commercial criteria are met prior to the commitment of capital to projects.

The third element is Internal Audit, whose role includes systematically examining the effectiveness of the Group's financial controls designed to assure the reliability of reporting and safeguarding of assets and examining the Group's compliance with laws, regulations and internal standards.

The fourth element is a quarterly due diligence review, which is separate and independent from the operating business units, of proved reserves associated with properties where technical, operational or commercial issues have arisen.

The fifth element is the established criteria whereby proved reserve changes above certain thresholds require central authorization. Furthermore, the volumes booked under these authorization levels are reviewed on a periodic basis. The frequency of review is determined according to field size and ensures that more than 80% of the BP reserves base undergoes central review every two years and more than 90% is reviewed every four years.

There is no direct link between compensation for executive directors and reserves replacement. Below the level of the executive director in the Exploration and Production segment, no specific portion of compensation bonuses has been directly related to oil and gas reserves targets. Additions to proved reserves was one of several indicators by which the performance of a business unit in the Exploration and Production business segment was assessed for purposes of determining compensation bonuses. Other indicators included production costs, changes in working capital, drilling days, operating efficiency and greenhouse gas emissions.

For 2005, BP's variable pay programme for the senior managers in the Exploration and Production business segment will be based on Individual Performance Contracts. Individual Performance Contracts are made up of two elements, one of which is based on certain elements of financial performance (cash from operations, capital expenditure, divestments) of the Group as a whole. The other is based on agreed items from the business performance plan, one of which, if they choose, could relate to oil and gas reserves.

Details of our net proved reserves of crude oil, condensate, natural gas liquids and natural gas at December 31, 2004, 2003, and 2002 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 Supplementary Oil and Gas Information beginning on page S-1. We separately disclose our share of reserves held in equity-accounted companies (joint ventures and associated companies) although we do not control these entities or the assets held by such entities.

All of the Group's oil and gas reserves held in consolidated companies have been estimated by the Group's petroleum engineers. Of the oil and gas reserves held in equity-accounted companies, approximately 17% have been estimated by the Group's petroleum engineers. The majority of the rest consists of reserves in TNK-BP which have been estimated by independent engineering consultants. For significant properties where BP has adopted the proved reserve estimates of others, BP's petroleum engineers reviewed such estimates before making their assessment of volumes to be booked by BP.

Our proved reserves are associated with both concessions (tax and royalty arrangements) and production sharing agreements (PSAs). In a concession, the consortium of which we are a part is entitled to the reserves that can be produced over the licence period, which may be the life of the field. In a PSA, we are entitled to recover volumes that equate to costs incurred to develop and produce the reserves and an agreed share of the remaining volumes or the economic equivalent. As part of our entitlement is driven by the monetary amount of costs to be recovered, price fluctuations will have an impact on both production volumes and reserves. Twenty one per cent of our proved reserves are associated with PSAs. The main countries in which we operate under PSA arrangements are Algeria, Angola, Azerbaijan, Egypt, Indonesia and Vietnam.

The Company's proved reserves estimates for the year ended December 31, 2004 reported in this Form 20-F reflect year-end prices and some adjustments which have been made vis-à-vis individual asset reserve estimates based on different applications of certain SEC interpretations of SEC regulations relating to the use of technology (mainly seismic) to estimate reserves in the reservoir away from wellbores and the reporting of fuel gas (i.e., gas used for fuel in operations on the lease) within proved reserves. The 2004 year-end marker prices used were Brent $40.24/bbl and Henry Hub $6.01/mmbtu. The other 2004 movements in proved reserves, are reflected in the tables showing movements in oil and gas reserves by region in Item 18 Financial Statements Supplementary Oil and Gas Information on pages S-1 to S-8.

Total hydrocarbon proved reserves, on an oil equivalent basis and excluding equity-accounted entities, comprised 14,626 mmboe at December 31, 2004, a decrease of 2.5% compared with December 31, 2003. Natural gas represents about 54% of these reserves. This reduction includes net sales of 144 mmboe comprising a number of assets in Egypt, Indonesia and the United States, and dilution of our interest in the reserves of the North West Shelf (NWS) in Australia. The proved reserve replacement ratio was 78% (2003 119%, 2002 175%). The proved reserve replacement ratio (also known as the production replacement ratio) is the extent to which production is replaced by proved reserve additions. This ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery, extensions, discoveries and other additions, excluding the impact of sales and purchases of reserves-in-place and excluding reserves related to equity-accounted entities. The proved reserve replacement ratio, including sales and purchases of reserves-in-place but excluding equity-accounted entities, was 64% (2003 39%, 2002 190%). The proved reserve replacement ratio for equity-accounted entities alone was 114% (2003 72%, 2002 100%), and the proved reserve replacement ratio for equity-accounted entities alone but including sales and purchases of reserves-in-place was 170% (2003 769%, 2002 270%). By their nature, there is always some risk involved in the ultimate development and production of reserves, including but not limited to final regulatory approval, the installation of new or additional infrastructure as well as changes in oil and gas prices and the continued availability of additional development capital.

In 2004, total additions to the Group's proved reserves (excluding sales and purchases of reserves-in-place and equity-accounted entities) amounted to 796 mmboe, mostly through extensions to existing fields and discoveries of new fields. Of these reserve additions, approximately 64% are associated with new projects and are proved undeveloped reserve additions and the remainder are in existing developments where they represent a mixture of proved developed and proved undeveloped. Major new development projects typically take one to four years from the time of initial booking to the start of production. The principal reserve additions were in Angola (Rosa), Egypt (Taurt and Saqqara), Indonesia (Tangguh) and Trinidad (Chachalaca) and it is planned to bring these into production over the period 2007 - 2009.

Total hydrocarbon proved reserves, on an oil equivalent basis for equity-accounted entities alone, comprised 3,672 mmboe at December 31, 2004, an increase of 9.2% compared with December 31, 2003. Natural gas represents about 13% of these reserves. This increase includes purchases of 252 mmboe associated with the TNK-BP acquisition of Slavneft and sales of 4 mmboe.

Additions to proved developed reserves in 2004 for subsidiaries were 720 mmboe. This included some reserves which were previously classified as proved undeveloped. The proved developed reserve replacement ratio (including both sales and purchases of reserves-in-place) was 70% (2003 -2%, 2002 103%).

Additions to proved developed reserves in 2004 for equity-accounted entities were 799 mmboe. This included some reserves which were previously classified as proved undeveloped. The proved developed reserve replacement ratio (including both sales and purchases of reserves-in-place) was 180% (2003 642%, 2002 265%).

Our total hydrocarbon production during 2004 averaged 2,795 thousand barrels of oil equivalent per day (mboe/d), for subsidiaries and 1,202 mboe/d, for equity accounted entities, a decrease of 7.2% and an increase of 101.8%, respectively, compared with 2003. For subsidiaries this decrease includes 95 mboe/d impact of divestments and for equity-accounted entities an increase of 108 mboe/d from the TNK-BP share of Slavneft following its inclusion within TNK-BP in January 2004. For subsidiaries, 41% of our production was in the USA, 19% in the UK. For equity-accounted entities, 76% of production is from TNK-BP and the former Sidanco.

Total production for 2005 is estimated at an average of between 2.85 and 2.9 mmboe/d for subsidiaries and between 1.25 and 1.3 mmboe/d for equity accounted entities; these estimates are before any divestments and are based on our $20/bbl planning basis. The exact level will depend on oil prices, divestments and many other factors.

The anticipated decline in production volumes from subsidiaries in our existing profit centres is partly mitigated by the development of new projects and the investment in incremental reserves in and around existing fields. We expect that this overall decline in production from subsidiaries in our existing profit centres will be more than compensated for by strong increases in production from subsidiaries in our new profit centres over the next few years. Production in our equity-accounted joint venture, TNK-BP, is also expected to grow over the next few years.

The most important determinants of cash flows in relation to our oil and natural gas production are the prices of these commodities. In a stable price environment, cash flows from currently developed proved reserves are expected to decline in a manner consistent with anticipated production decline rates. Development activities associated with recent discoveries, as well as continued investment in these producing fields, are expected to more than offset this decline, resulting in increased operating cash flows over the next few years. Cash flows from equity-accounted entities are expected to be in the form of dividend payments.

The following tables show BP's estimated net proved reserves as at December 31, 2004.

Estimated net proved reserves of liquids at December 31, 2004 (a) (b)

	Developed	**Undeveloped**	**Total**
		(millions of barrels)	
UK	559	210	769
Rest of Europe	231	109	340
USA	2,041	1,211	3,252
Rest of Americas	311	299	610(c)
Asia Pacific	65	85	150
Africa	204	643	847
Russia			
Other	62	725	787
	3,473	3,282	6,755
Equity-accounted entities			3,179(d)

Estimated net proved reserves of natural gas at December 31, 2004 (a) (b)

	Developed	Undeveloped	Total
	(billion cubic feet)		
UK	2,498	1,183	3,681
Rest of Europe	248	1,254	1,502
USA	10,811	3,270	14,081
Rest of Americas	4,101	10,663	14,764(e)
Asia Pacific	1,624	5,419	7,043
Africa	1,015	1,886	2,901
Russia			
Other	282	1,396	1,678
	20,579	25,071	45,650
Equity-accounted entities			2,857(f)
Net proved reserves on an oil equivalent basis (mmboe)			
Group			14,626
Equity-accounted entities			3,672

(a) Net proved reserves of crude oil and natural gas, stated as of December 31, 2004, exclude production royalties due to others, whether payable in cash or in kind, and include minority interests in consolidated operations. We disclose our share of reserves held in joint ventures and associated undertakings that are accounted for by the equity method although we do not control these entities or the assets held by such entities.

(b) In certain deepwater fields, such as fields in the Gulf of Mexico, BP has claimed proved reserves before production flow tests are conducted in part because of the significant safety, cost and environmental implications of conducting these tests. The industry has made substantial technological improvements in understanding, measuring and delineating reservoir properties without the need for flow tests. The general method of reserves assessment to determine reasonable certainty of commercial recovery which BP employs relies on the integration of three types of data: (1) well data used to assess the local characteristics and conditions of reservoirs and fluids; (2) field scale seismic data to allow the interpolation and extrapolation of these characteristics outside the immediate area of the local well control; and (3) data from relevant analog fields. Well data includes appraisal wells or sidetrack holes, full logging suites, core data and fluid samples. BP considers the integration of this data in certain cases to be superior to a flow test in providing a better understanding of the overall reservoir performance. The collection of data from logs, cores, wireline formation testers, pressures and fluid samples calibrated to each other and to the seismic data can allow reservoir properties to be determined over a greater volume than the localized volume of investigation associated with a short term flow test.

Historically, proved reserves recorded using these methods have been validated by actual production levels. BP has booked proved reserves in 18 fields in the deepwater Gulf of Mexico prior to production flow testing. Fifteen of these were in production at December 31, 2004 and Mad Dog commenced production in January 2005. Thunder Horse and Atlantis are due to begin production over the period 2005-2006.

(c) Includes 40 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

(d) Includes 127 million barrels of crude oil in respect of the 5.9% minority interest in TNK-BP.

(e) Includes 4,064 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

(f)

Includes 13 billion cubic feet of natural gas in respect of the 5.9% minority interest in TNK-BP.

The following tables show BP's production by major field for 2004, 2003 and 2002.

Liquids

Production	Field or Area	Interest	Net production 2004	2003	2002
		(%)	(thousand barrels per day)		
Alaska	Prudhoe Bay*	26.4	97	105	113
	Kuparuk	39.2	68	73	74
	Northstar*	98.6	49	46	36
	Milne Point*	100.0	44	44	44
	Other	Various	37	43	42
Total Alaska			295	311	309
Lower 48 onshore (a)	Total	Various	142	160	192
Gulf of Mexico (a)	Horn Mountain*	66.6	41	42	1
	Mars	28.5	35	43	41
	Ursa	22.7	29	17	20
	Na Kika*	50.0	27		
	King*	100.0	26	31	12
	Other	Various	71	122	190
Total Gulf of Mexico			229	255	264
Total USA			666	726	765
UK offshore (a)	ETAP	Various	55	56	61
	Foinaven*	Various	48	55	72
	Schiehallion/Loyal*	Various	39	42	43
	Magnus*	85.0	34	39	31
	Harding*	70.0	27	34	42
	Andrew*	62.8	12	17	23
	Other	Various	89	105	157
Total UK offshore			304	348	429
Onshore	Wytch Farm*	67.8	26	29	32
Total UK			330	377	461
Netherlands	Various	Various	1	1	1
Norway (a)	Draugen	18.4	27	25	37
	Valhall*	28.1	25	21	21
	Ula*	80.0	16	16	18
	Other	Various	8	21	27
Total Rest of Europe			77	84	104

* BP operated.

BP operates the majority of the fields in this area.

Production		Field or Area	Interest	Net production 2004	2003	2002
			(%)	(thousand barrels per day)		
Angola		Girassol	16.7	31	33	29
		Xikomba	26.7	18	2	
		Kizomba A	26.7	16		
		Other	Various	6		
Australia		Various	15.8	36	40	43
Azerbaijan		Azeri-Chirag-Gunashli*	34.1	39	38	38
Canada		Various	Various	11	13	16
Colombia		Various	Various	48	53	46
Egypt		Various	Various	57	73	85
Trinidad		Various	100.0	59	74	67
Venezuela (a)		Various	Various	55	53	51
Other (a)		Various	Various	31	49	61
Total Rest of World				407	428	436
Total Group				1,480	1,615	1,766
Equity-accounted entities						
Abu Dhabi (b)		Various	Various	142	138	113
Argentina	- Pan American Energy	Various	Various	64	60	53
Russia	- TNK-BP (a)	Various	Various	831	296	73
Other		Various	Various	14	12	13
Total equity-accounted entities				1,051	506	252

* BP operated.

Natural gas

Production	**Field or Area**	**Interest**	**Net production 2004**	**2003**	**2002**
		(%)	(million cubic feet per day)		
Lower 48 States onshore (a)	San Juan*	Various	772	802	797
	Arkoma	Various	183	201	206
	Hugoton*	Various	158	182	169
	Jonah*	65.0	114	119	113
	Wamsutter*	70.5	105	111	108
	Tuscaloosa	Various	96	136	138
	Other	Various	514	558	715
Total Lower 48 onshore			1,942	2,109	2,246
Gulf of Mexico (a)	Na Kika*	50.0	133		
	Marlin*	78.2	43	93	106
	King's Peak*	55.0	39	91	16
	Other	Various	514	752	1,063
Total Gulf of Mexico			729	936	1,185
Alaska	Various	Various	78	83	52
Total USA			2,749	3,128	3,483
UK offshore (a)	Bruce*	37.0	163	222	221
	Braes	Various	147	174	116
	Shearwater	27.5	76	70	66
	Marnock*	62.0	70	98	135
	West Sole*	100.0	67	73	72
	Britannia	9.0	54	55	56
	Armada	18.2	50	58	71
	Other	Various	547	696	813
Total UK			1,174	1,446	1,550
Netherlands	P/18-2*	48.7	34	30	41
	Other	Various	46	37	46
Norway (a)	Various	Various	45	52	60
Total Rest of Europe			125	119	147

* BP operated.

2004 includes 7 million cubic feet a day of natural gas received as in-kind tariff payments.

Production	Field or Area	Interest	Net production 2004	2003	2002
		(%)	(million cubic feet per day)		
Australia	Various	15.8	308	285	295
Canada	Various	Various	349	422	514
China	Yacheng	34.3	99	74	102
Egypt	Ha'py*	50.0	80	83	74
	Others	Various	115	170	182
Indonesia	Sanga-Sanga (direct)*	26.3	137	165	174
	Pagerungan*	100.0	68	121	189
	Other*	46.0	76	97	94
Sharjah	Sajaa*	40.0	103	101	110
	Other	40.0	14	19	24
Trinidad	Kapok*	100.0	553	79	
	Mahogany*	100.0	453	503	521
	Amherstia*	100.0	408	624	492
	Immortelle*	100.0	172	235	154
	Parang*	100.0	137	152	
	Cassia*	100.0	85	30	
	Flamboyant*	100.0	67	68	40
	Other*	100.0	44	3	31
Other (a)	Various	Various	308	168	148
Total Rest of World			3,576	3,399	3,144
Total Group (c)(d)			7,624	8,092	8,324
Equity-accounted entities					
Argentina - Pan American Energy	Various	Various	317	281	251
Russia - TNK-BP (a)	Various	Various	458	129	6
Other	Various	Various	104	111	126
Total equity-accounted entities (d)			879	521	383

*
BP operated

(a)
In 2004, BP agreed with AAR to incorporate their 50% interest in Slavneft into TNK-BP, an equity-accounted entity. BP also acquired minor additional working interests in Canada and the United States. BP diluted its working interests in King's Peak and divested the Swordfish assets in the deepwater Gulf of Mexico. Additionally, BP sold various properties including its interest in the South Pass 60 in the Gulf of Mexico Shelf, various assets in Alberta in Canada, and the Kangean Production Sharing Contract (PSC) in Indonesia. In 2003, BP and AAR merged certain of their Russian and Ukranian oil and gas businesses to create TNK-BP. BP also acquired the interests of Amerada Hess in Colombia and disposed of its interests in Forties, Montrose/Arbroath and Bacton Area assets in the UK North Sea, Gyda in Norway, LL652 in Venezuela, QHD and Liuhua in China, the Malaysia Thailand Joint Development Area, Aspen in the Gulf of Mexico, various shallow water fields in the Gulf of Mexico and various fields in the US Lower 48 states. In 2002, BP acquired additional working interest in the Badin acreage (Pakistan) from the government and disposed of its interest in the Al Rayyan field (Qatar), Qadirpur field (Pakistan) and Elgin/Franklin field (UK).

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

(c) Includes NGLs from processing plants in which an interest is held of 67 mb/d, 70 mb/d, and 69 mb/d for 2004, 2003 and 2002, respectively. The related reserves are excluded from the Group's reserves.

(d) Natural gas production volumes exclude gas consumed in operations within the lease boundaries of the producing field, but the related reserves are included in the Group's reserves.

United States

2004 liquids production at 666 thousand barrels per day (mb/d) decreased 8% from 2003, while natural gas production at 2,749 million cubic feet per day (mmcf/d) decreased 12% compared with 2003.

On September 15, 2004, Hurricane Ivan passed directly over the eastern portion of the Gulf of Mexico requiring the shut-in of all BP's floating facilities in the area. These conditions resulted in damage to operated and non-operated assets in both our upstream and midstream activitites. Repairs have been completed.

Crude oil production decreased 60 mb/d, with production from new projects being offset by the impact of Hurricane Ivan and natural reservoir decline. The decline in the NGLs component of liquids production (12 mb/d) was primarily caused by divestments. Gas production was lower (379 mmcf/d) because of Hurricane Ivan, divestments, natural reservoir decline and investment choices.

Development expenditure in the USA (excluding midstream) during 2004 was $3,248 million, compared with $3,474 million in 2003 and $3,607 million in 2002. This reflects our continued focus on investing in the best opportunities and optimizing operating efficiency.

Our activities within the United States take place in four main areas. Significant events during 2004 within each of these are indicated below.

Deepwater Gulf of Mexico

Deepwater Gulf of Mexico is one of our new profit centres and our largest area of growth in the United States. In 2004, our deepwater Gulf of Mexico crude oil production was 182.3 mb/d and gas production was 489 mmcf/d. On November 28, the profit centre achieved a record production rate of 360 mboe/d.

Significant events included:

- Production from the Holstein field (BP 50% and operator) commenced in December. The Holstein development consists of a moored floating platform, equipped with facilities for simultaneous production and drilling operations.

- Installation of the Mad Dog platform was completed in 2004. Production from the Mad Dog field (BP 60.5% and operator) commenced in January 2005. The platform is equipped with facilities for simultaneous production and drilling operations.

- Na Kika's first oil was produced November 26, 2003 with the ramp up continuing into early 2004 and completed ahead of schedule.

Development of two major projects continued in the Gulf of Mexico during 2004 Thunder Horse (BP 75% and operator) is scheduled to commence production in 2005 with Atlantis (BP 56% and operator) following in 2006. Along with Holstein and Mad Dog, these projects will be the major contributor to the anticipated growth in production over the next several years.

In 2004, BP divested its interest in the Swordfish Development and completed the sale of approximately one half of its interest in the Troika asset.

Gulf of Mexico Shelf

The Shelf is a mature basin, with decline rates that average 40-50% per year. In accordance with our strategy, in the third quarter of 2004, we continued to increase the quality of our portfolio by completing the disposal of the Vermilion 14, Eugene Island 240, Main Pass 264 and South Pass 60 properties. These fields accounted for approximately 42 mmcf/d. Our gas production from Gulf of Mexico Shelf operations was 240 mmcf/d in 2004, down 36% compared to 2003. Liquids production was

24 mb/d, down 38% compared to 2003. The year-on-year drop in production was the result of the divestment programme, normal decline, the effects of Hurricane Ivan and reduced capital spending.

Lower 48 States

In the Lower 48 States (Onshore), our 2004 natural gas production was 1,942 mmcf/d, which was down 8% compared to 2003. Liquids production was 142 mb/d, down 11% compared to 2003. The year-on-year decrease in production is attributed to normal decline. In 2004, we drilled approximately 400 wells as operator and continued to maintain a level programme of drilling activity throughout the year.

Production is derived primarily from two main areas:

In the Western Basins (Colorado, New Mexico, and Wyoming) our assets produced 221 mboe/d in 2004.

In the Gulf Coast and Mid-Continental basins (Kansas, Louisiana, Oklahoma and Texas) our assets produced 190 mboe/d in 2004.

Significant events included:

Acquisition of Kerr McGee's interests in the Arkoma Red Oak and Williburton fields in exchange for the Gulf of Mexico Deep Water Blindfaith prospect. The deal closed on February 1, 2005.

Wyoming Oil & Gas commission approval of our application for field-wide 10-acre spacing in the Jonah field, allowing for approximately 500 potential locations, and 80-acre spacing in the Wamsutter field, allowing for approximately 3,000 potential locations. The increased density of drilling locations allows an acceleration of production.

Alaska

In Alaska, BP net crude oil production in 2004 was 295 mb/d, a decrease of 5% from 2003, due principally to mature field decline partially offset by increases in Northstar production and development of satellite fields around Prudhoe Bay and Kuparuk.

Key activities in Alaska:

Maximizing productivity through active reservoir management of the fields we operate remains an essential part of the Alaska business. In 2004, BP operated drilling activity across the North Slope totalling 7.7 rig-years. Prudhoe Bay, and the associated satellite fields (BP 26.4% and operator) maintained an active infill and new well drilling programme with 91 wells in 2004, which generated net production of 6.8 mboe/d. At the Milne Point Unit, 20 wells were drilled with 19 miles of horizontal hole achieving 29% lower non-productive time than the previous year while increasing net production by 4 mboe/d. The Northstar Unit drilled three wells in 2004, including an Extended Reach Drilling well that achieved 20,207 feet, a North Slope record. The Endicott Unit drilled three Coiled Tubing sidetrack wells that generated net production of 0.6 mboe/d.

Developing viscous oil is a key piece of the Alaska strategy. Viscous production is being developed in large part through the application of horizontal multilateral wells. In 2004, BP completed the first ever quadri-lateral well in Alaska and launched the first penta-lateral well in Alaska, completing it in early 2005. In pursuance of our strategy we intend to review facility capacity and potential acceleration of development.

Negotiations on the Gas Pipeline fiscal contract with the State of Alaska are continuing. BP, along with partners ExxonMobil and ConocoPhillips, recently provided the State Administration with a comprehensive fiscal contract proposal that would establish a clear and predictable fiscal regime in Alaska.

The State of Alaska decided on January 12, 2005 to aggregate six of the satellite fields around Prudhoe Bay with the Prudhoe Bay field for the purposes of calculating production taxes. The State estimated that the impact for 2005 will be around $150 million in higher production taxes for the five owners (BP equity 26.4%). BP filed an appeal against this decision on March 11, 2005.

In 2003, the Alaska Oil and Gas Conservation Commission proposed an enforcement action and a penalty in excess of $2.5 million in regard to the August 2002 A-22 well explosion. BP contested the penalty and in 2004 the Commission reduced the penalty to $1.3 million and in addition allowed a credit for the $549,000 which BP Exploration Alaska (BPXA) had expended subsequent to the incident on a pilot programme to determine the feasibility of remote monitoring of outer annulus pressures. Thus, the net penalty will be approximately $717,000. Although we strongly believe no violation of law occurred, BPXA and its Prudhoe Bay Unit Working Interest Owners have agreed not to contest the adjusted penalty.

United Kingdom

We are the largest producer of oil and second largest producer of gas in the UK. BP remains the largest overall producer in the UK of hydrocarbons. In 2004, total liquids production was 330 mb/d, a 12% decrease on 2003, and gas production was 1,174 mmscf/d, a 19% decrease on 2003. This decrease in production was driven by the full year's impact of the assets divested in 2003, namely Forties, Montrose/Arbroath and Bacton Area assets, representing 35% of the decrease, along with the natural decline of the mature North Sea basin (65% of the decrease). Our activities in the North Sea are focused on operations efficiency, in-field drilling and selected new field developments. Our development expenditure in the UK was $679 million in 2004 compared to $740 million in 2003 and $895 million in 2002.

Significant activities included the following:

Construction of the Clair Phase 1 development (BP 28.6% and operator) was completed with the installation of the jacket and decks in July and August. The first well was re-entered in December 2004 and first oil was produced in February 2005.

Drilling commenced in July 2004 on the Rhum project (BP 50% and operator) with production start-up scheduled for late 2005.

BP obtained DTI approval for the $130 million development of the Farragon oil discovery (BP 50% and operator).

The sanction for the $235 million Magnus Expansion Project (BP 85% and operator) was announced in October.

BP, on behalf of the owners of North West Hutton (BP 26% and operator), submitted the proposed decommissioning programme to the DTI in November. North West Hutton ceased production in January 2003.

Rest of Europe

Development expenditure, excluding midstream, in the Rest of Europe was $262 million compared with $236 million in 2003 and $219 million in 2002.

Norway

In 2004, total Norway production was 84 mboe/d, a 9% decrease on 2003. This decrease in production was driven by the divestment of the Gyda asset to Talisman, natural decline and shutdown of the Tambar field for just over three months owing to operational problems. The decrease was partly offset by high operational efficiency on the BP operated Ula and Valhall fields, and new wells coming on stream on the two Valhall Flank platforms. The Tambar field was returned to production during the year.

Significant activities included the following:

On November 20, 2004, we entered into an agreement with the Danish utility company, DONG, to sell our 10.3% interest in the Ormen Lange development and our 10.2% interest in the Langeled gas export pipeline. The agreement was completed on February 28, 2005 with effect from January 1, 2005.

Water injection commenced on Valhall (BP 28.1% and operator) in 2004. The concept for the Valhall redevelopment was progressed in 2004, targeting installation of a new Valhall platform in 2009.

Rest of World

Development expenditure, excluding midstream, in Rest of World was $3,082 million in 2004 compared with $3,085 million in 2003 and $2,503 million in 2002.

Rest of Americas

Canada

In Canada, our natural gas and liquids production was 71 mboe/d in 2004, a decrease of 17% compared to 2003. The year-on-year reduction in production is mainly due to natural field decline, shut-in gas production and non-core asset sales. The Alberta Energy and Utilities Board ordered the industry to shut in production from certain shallow gas fields overlaying bitumen deposits in northeastern Alberta with effect from September 1, 2003. In December, 2004 the Alberta Government put in place a compensation scheme for companies, including BP, impacted by the shut-in order.

On March 16, 2005, BP and Chevron sold Central Alberta Midstream, their jointly owned midstream gas processing business, to SemCAMS Midstream Company, a wholly owned subsidiary of SemGroup, L.P.

Trinidad

In Trinidad, natural gas production volumes increased by 13%, to 1,919 mmbcf/d in 2004. The increase was principally driven by the successful startup of the Atlas Methanol plant with its first production in the third quarter of 2004. A full year of sales to Atlantic LNG Train 3 and the improvements made to operating efficiency levels of the existing Trains 1, 2 and 3 also contributed to this increase. Liquids production declined by 15 mb/d (20%), to 59 mb/d in 2004 owing to various operational factors.

Work on Cannonball, our next field development, continues on target. This is Trinidad's first major offshore construction project executed locally. Cannonball will provide gas deliverability for Atlantic LNG Train 4 (BP 37.8%), with expected production of 500 mmscf/d from two wells and first gas targeted for the fourth quarter of 2005.

The Atlas Methanol Plant (BP 36.9%) operated by Methanex, came onstream in June 2004. BP Trinidad and Tobago supplied 100% of the gas feedstock requirement, averaging 156 mmscf/d in the final quarter of 2004.

Venezuela

In Venezuela, three of the four base assets are reactivation projects (projects that are expected to continue and improve exploitation in mature fields) consisting of two operated properties, Boqueron and Desarollo Zulia Occidental (DZO), and one non-operated property, Jusepin, under risk service agreements to produce oil for the state oil company, Petroleos de Venezuela S.A. (PDVSA). During 2003, we executed a sale and purchase agreement to sell DZO and

Boqueron to Perenco. In the first quarter of 2004, the sales agreement lapsed and we will now retain these fields. We had previously reported an exceptional loss on disposal of $217 million in respect of these assets, which has now been reversed. As a result of the lapse of the agreement, an impairment charge of $186 million was recognized in the first quarter of 2004. A fourth asset, Cerro Negro, is a non-operated property that is a heavy oil project from which production is sold directly by BP.

In October 2004, the royalty rate for Cerro Negro increased from 1% to 16.67% as a result of the Government's decision to end the fiscal relief granted for the Orinoco belt heavy oil strategic associations. In 2005, proposals have been made by the government to raise royalty to 30% and increase income tax to 50% from 34%, and discussions have begun between the national tax authorities and foreign oil companies, including BP, in respect of taxes on previous production.

Colombia

In Colombia, BP's net production averaged 58 mboe/d. Main production comes from the Cusiana, Cupiagua and Cupiagua South Fields with increasing new production from the Cupiagua extension into the Recetor Association Contract and the Floreña and Pauto fields in the Piedemonte Association contract.

During 2004, BP started building the upgrade of the existing gas processing facilities (BP 24.8%) from 40 to 180 mmscf/d of capacity to supply the domestic market. The project is expected to be completed by the end of 2005.

Argentina and Bolivia

In Argentina and Bolivia, activity is conducted through Pan American Energy (PAE), in which BP holds a 60% interest, and which is accounted for by the equity method. In 2004, total production of 129 mboe/d represented an increase of 10% over 2003, with oil increasing by 7% and gas by 13%. The main increase in oil production came from the continued focus on drilling and waterfloods in Golfo San Jorge in Argentina, where oil production was 56 mb/d compared to 52 mb/d in 2003. The field is now producing at its highest level since inception in 1958 and further expansion programmes are planned. PAE also has interests in gas pipelines, electricity generation plants and other midstream infrastructure assets.

In Bolivia in May 2005, a new hydrocarbons law established a new production tax of 32% in addition to the existing 18% royalty. Foreign oil and gas companies are required to sign new contracts conforming with the new law.

Africa

Algeria

BP, through its joint operatorship of In Salah Gas with Statoil and the Algerian state company, Sonatrach, completed the development of the In Salah project (BP 33.15%). This first stage comprised the development of three of the seven deep Saharan natural gas fields expected to supply the fast-growing markets of Southern Europe. In Salah commenced commercial production on July 18, 2004, and produced a total of 105 billion cubic feet (bcf) (Gross) of which BP's net share was 26 bcf.

BP, through its joint operatorship of In Amenas with Statoil and Sonatrach, continued to progress the development of the In Amenas project (BP 50% before production, 12.5% after start of production) with production expected to start in early 2006.

Angola

BP has interests in four deepwater licence blocks, including two of which it is operator. We have built a strong foundation for long-term growth in Angola through both exploration and development.

Activities in 2004 included the following:

- In Block 15 (BP 26.7%), Kizomba A commenced production in the third quarter of 2004. Development activities progressed on Kizomba B, with production expected to commence in the second half of 2005.

- In Block 17 (BP 16.7%), development activities progressed on the Dalia project in line with expectations to commence production in the second half of 2006. The Rosa project, a tie-back to Girassol hub, commenced development in the third quarter of 2004.

- In Block 18 (BP 50% and operator), work has continued on the Greater Plutonio development in line with expectations to commence production in 2007. At the end of 2004, Shell assigned its 50% equity share in the project to Sonangol.

- In Block 31 (BP 26.7% and operator), we had made four discoveries by the end of 2004 which are at various stages of assessment of commercial viability. A further two discoveries were announced in 2005.

Egypt

- In Egypt, the Gulf of Suez Petroleum Company (GUPCO), a joint venture operating company between BP and the Egyptian General Petroleum Corporation, carries out our oil production operations. GUPCO operates eight PSAs in the Gulf of Suez and Western Desert encompassing more than forty fields.

- During 2004, BP Egypt and upstream partner IEOC, a subsidiary of Italy's ENI, signed agreements with the Egyptian General Petroleum Corporation (EGPC) and Egyptian Natural Gas Holding Company (EGAS), to deliver up to 310 mmscf/d of natural gas to the Damietta LNG plant starting from 2008. In parallel, BP's Gas, Power and Renewables business has signed an agreement with EGAS, to purchase 1.45 billion cubic metres a year (bcma) of LNG from 2005, when the Damietta LNG plant is expected to start commercial production. This deal marks the first BP integrated gas supply and LNG purchase agreement.

- During the third quarter of 2004 there was a blow out and subsequent fire on the partner-operated Temsah North West platform (BP 50%). Drilling of relief wells was successfully carried out by the operator resulting in the extinguishing of all the ignited wells at the end of October. Plans for the redevelopment of Temsah North West through a replacement platform and facilities are progressing.

- During the third quarter of 2004, BP successfully completed the disposal of the Offshore North Sinai concession.

- In May 2005, BP and the Egyptian Ministry of Petroleum signed agreements to extend the Merged Concession Agreement by 20 years and the South Gharib concession by 10 years from the date of signing. These concessions represent approximately 80% of BP's oil business in Egypt. These agreements will allow the maximization of the recovery of remaining reserves and provide for growth through future exploration activity.

Asia Pacific

Indonesia

BP produces crude oil and supplies natural gas to the island of Java through its holding in the Offshore Northwest Java Production Sharing Contract (PSC, BP 46%).

In the fourth quarter of 2004, BP approved its share of the investment in the Tangguh LNG project.

The sales of BP's interests in the Kangean PSC, which contained the Pagerungan field, and the Muriah non-producing PSC were completed in August and November 2004 respectively.

Vietnam

BP participates in the country's biggest foreign investment, the Nam Con Son gas project. This is an integrated resource and infrastructure project including offshore gas production, pipeline transportation system and power plant. Gas sales from Block 6.1 (BP 35% and operator) commenced in early 2003. The gas is sold under a long-term agreement for electricity generation in Vietnam, including the Phu My 3 power plant (BP 33.33%), which commenced operations on March 1, 2004.

China

The Yacheng field operatorship was transferred from BP to China National Offshore Oil Corporation (CNOOC) on January 1, 2004. The Yacheng field (BP 34.3%) supplies, under a long-term contract, 100% of the natural gas requirement of Castle Peak Power Company, which provides around 50% of Hong Kong's electricity. Some natural gas is also piped to Hainan Island, where it is sold to the Fuel and Chemical Company of Hainan, also under a long-term contract.

Australia

We are one of six equal partners (BP 15.8%) in the North West Shelf (NWS) Venture. The operation covers offshore production platforms, a floating production and storage vessel, trunklines, and onshore gas processing plants. The NWS Venture is currently the principal supplier to the domestic market in Western Australia. During 2004, a fourth LNG Train (4.2 million tonnes per annum) and a second trunkline were commissioned.

Russia

TNK-BP

TNK-BP (BP 50%) is an integrated oil company operating in Russia and the Ukraine. TNK-BP has proved reserves of 4.4 billion boe (including its 49.5% equity share of Slavneft), of which 3.8 billion are developed. Daily oil production currently amounts to some 1.7 million boe/d, including its share of Slavneft. The production base is largely centred in West Siberia (Samotlor, Nizhnevartovskoye Neftedobyvaushee Predpriyatie, Nyagan and Megion), which contributes about 1.0 million boe/d, together with Volga Urals (Orenburgneft) contributing 0.4 million boe/d. About 50% of total oil production is currently exported as crude oil and 15% as refined product. Downstream, TNK-BP owns six refineries in Russia and the Ukraine (including Ryazan and Lisichansk), with throughput of 0.5 million barrels a day (25 million tonnes a year). In retail, TNK-BP supplies more than 2,100 filling stations in Russia and the Ukraine, with a share of the Moscow retail market in excess of 20%. The workforce currently is about 100,000 people.

BP's investment in TNK-BP is held by the Exploration and Production business, and the results of TNK-BP are accounted for under the equity method in that segment.

TNK-BP Group Restructuring

On January 14, 2005, TNK-BP announced the details of its plans to restructure the group in Russia. A new holding company OAO TNK-BP Holding has been formed and now owns TNK-BPs interests in OAO ONAKO, OAO Sidanco and OAO TNK. On March 1, 2005, shareholders of these latter three companies approved a scheme of accession to OAO TNK-BP Holding. Included in the announcement on January 14, were the terms of a voluntary offer to minority shareholders of 14 material subsidiaries of the TNK-BP group to exchange their shares for shares in OAO TNK-BP Holding. The offer is expected to take place when the accessions near completion. On completion of the accessions and voluntary offer, TNK-BP will consider further accessions of material subsidiaries. OAO TNK-BP Holding will own all the TNK-BP group's material assets in Russia except for the group's interests in OAO Rusia Petroleum, the OAO Slavneft group and the BP branded retail sites in Moscow and the Moscow region.

Other

Middle East and Pakistan

Production in the Middle East principally consists of 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, respectively. In 2004, production in Abu Dhabi was 142 mb/d, up around 3% from 2003 as a result of OPEC quota increase and strong worldwide demand.

In Pakistan, BP is one of the leading foreign operators producing 36% of the country's oil and 7% of its natural gas on a gross basis.

Azerbaijan

BP, as operator of the Azerbaijan International Operating Company (AIOC), manages and has a 34.1% interest in the Azeri-Chirag-Gunashli (ACG) oil fields in the Caspian Sea, offshore Azerbaijan. The Azeri project delivered first oil from central Azeri to Sangachal terminal on March 3, 2005. Successive phases of the project include West Azeri and East Azeri scheduled to come on stream in 2006 and 2007, respectively, and ACG Phase 3 Deepwater Gunashli, which was approved in September 2004, and is expected to begin production in 2008.

The Shah Deniz natural gas field (BP 25.5% and operator) was sanctioned in 2003 and remains on track to deliver first gas in 2006. The stage 1 pre-drilling programme was completed in July 2004 with the third well being successfully suspended. Assembly and installation of the modules and associated equipment for the platform is expected to be completed during the second half of 2005. Phase 2 is scheduled to begin in the first half of 2006 with the drilling of the fourth assessment well.

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 (TAPS) in the USA and the Forties Pipelines System (FPS) in the UK sector of the North Sea. We also operate the Central Area Transmission System (CATS) for natural gas in the UK sector of the North Sea.

BP, as operator, manages and holds a 30.1% interest in the Baku-Tbilisi-Ceyhan (BTC) oil pipeline inaugurated in May 2005. BP, as operator of AIOC, also operates the Western Export Route Pipeline between Azerbaijan and the Black Sea coast of Georgia and the Azeri leg of the Northern Export Route Pipeline between Azerbaijan and Russia.

Our onshore US crude oil and product pipelines and related transportation assets are included under "Refining and Marketing" in this item. Revenue is earned on pipelines through charging tariffs. Our gas marketing business is described under "Gas, Power and Renewables" in this item.

Activity in oil and natural gas transportation during 2004 included:

Alaska

BP owns a 46.9% interest in TAPS, with the balance owned by four other companies. TAPS transported production from Alaska North Slope fields averaged 927 mb/d during 2004.

The TAPS owners are implementing a project to upgrade and modernize four pump stations beginning in 2005. This project will install electrically driven pumps at four critical pump stations, combined with increased automation and upgraded control systems.

There are a number of unresolved protests regarding intrastate tariffs charged for shipping oil through TAPS. These protests were filed between 1986 and 2003 with the Regulatory Commission of Alaska (RCA). In 2002 and 2004, the RCA issued Orders requiring refunds to be made to TAPS shippers of intrastate crude oil for the period from January 1, 1997 through June 30, 2003. BP has appealed these RCA Orders to the Alaska Superior Court. Pending the resolution of these matters the RCA has imposed intrastate rates (consistent with its 2002 Order) effective July 1, 2003. The appeal process continues.

Tariffs for interstate and intrastate transportation on TAPS are calculated utilizing the Federal Energy Regulatory Commission (FERC) endorsed TAPS Settlement Methodology (TSM) entered into with the State of Alaska in 1985. In December 2004, the State and Anadarko filed protests at FERC of the 2005 rates on a variety of grounds. We are confident that the rates are in accordance with the TSM but are evaluating the protests.

The use of US-built and US-flagged ships is required when transporting Alaskan oil to markets in the USA. BP has begun replacing its US-flagged fleet as existing ships are retired in accordance with the Oil Pollution Act of 1990. For discussion of the Oil Pollution Act of 1990, see Environmental Protection Maritime Oil Spill Regulations in this Item on page 75. BP has contracted for the delivery of four 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 the National Steel and Shipbuilding Company in San Diego, CA. BP took delivery of the first of the four state-of-the-art double-hull tankers, the Alaskan Frontier, in August, 2004 and the second, the Alaskan Explorer, in March 2005. The third is expected to be delivered in the fourth quarter of 2005 and the fourth in 2006. In addition to the Alaskan Frontier and Explorer, BP America Inc. has a chartered fleet of seven US-flagged tankers to transport Alaskan crude oil to markets.

North Sea

FPS (BP 100%) is an integrated oil and NGLs transportation and processing system that handles production from over 40 fields in the Central North Sea. The system has a capacity of more than 1 mmb/d, with average throughput in 2004 at 697 mb/d. In 2004, we successfully completed the connection of the Buzzard field into the system. This was the first time that a subsea welded hot-tap technology had been applied in this way in the North Sea, allowing FPS to remain in production while the connection was made.

BP operates and has a 29.5% interest in 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 to a natural gas terminal at Teesside in northeast England. CATS offers natural gas transportation services or transportation and processing via two 600 mmcf/d processing trains. In 2004, throughput was 1.4 bcf/d (gross), 405mcf/d (net).

In addition, BP operates the Dimlington/Easington gas processing terminal (BP 100%) on Humberside and the Sullom Voe Gas Terminal in the Shetlands.

Asia (including the former Soviet Union)

BP, as operator, manages and holds a 30.1% interest in the BTC oil pipeline which was inaugurated in May 2005. The 1,770 kilometre pipeline is expected to carry one million barrels of oil a day from the BP-operated ACG oilfield in the Caspian Sea to the eastern Mediterranean port of Ceyhan. The filling of the pipeline with oil commenced in May, and loading of the first tanker at Ceyhan is expected in the fourth quarter of 2005.

The South Caucasus Pipeline (SCP) for the transport of gas from Shah Deniz in Azerbaijan to the Turkish border is under construction and scheduled to be mechanically complete at the end of 2005. BP is the operator and holds a 25.5% interest.

Through the LukArco joint venture, BP holds a 5.75% interest (with a 25% funding obligation) in the Caspian Pipeline Consortium (CPC) pipeline. CPC is a 1,510-kilometre pipeline from Kazakhstan to the Russian port of Novorossiysk. The initial construction phase was completed in April 2003. The pipeline has an initial capacity of 28.2 million tonnes (approximately 225 mmboe) a year and carries crude oil from the Tengiz field (BP 2.3%). In addition to our interest in LukArco, we hold a separate 0.87% interest (3.5% funding obligation) in CPC through a 49% holding in Kazakhstan Pipeline Ventures. In 2004, CPC total throughput reached 22.5 million tonnes. This increased within the year and throughput for the month December 2004 reached the equivalent of 33.1 million tonnes on an annual basis.

Gulf of Mexico

Construction continued on the Mardi Gras pipeline system (BP approximately 65% and operator). When complete, the network of pipelines will extend in total more than 450 miles, and lie in waters of greater than 7,000 feet deep. The segments associated with Na Kika, Holstein and Mad Dog have been commissioned and are currently in operation. The segments supporting Thunder Horse and Atlantis will be commissioned in conjunction with the start-up of those fields in 2005 and 2006, respectively.

From January 1, 2005 the Mardi Gras pipeline has been transferred to the Refining and Marketing segment.

Liquefied Natural Gas

Within BP, Exploration and Production is responsible for the supply of LNG and the Gas, Power and Renewables business is responsible for the subsequent marketing and distribution of LNG (see details under Gas, Power and Renewables New Market Development and LNG in this Item on page 67). BP Exploration and Production has interests in four major LNG plants. The Atlantic LNG plant in Trinidad (BP 34% in Train 1, 42% in Trains 2 and 3, and 37.8% in Train 4); in Indonesia through our interests in Sanga-Sanga PSA, (BP 38%), which supplies natural gas to the Bontang LNG plant, and Tangguh (PSA, BP 37%), which is under construction; and in Australia through our share of LNG from the North West Shelf natural gas development (BP 16.7%).

Significant activity during 2004 included the following:

We have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2004 supplied 5.9 million tonnes (302 bcf) of LNG, up 9% on 2003.

In Australia, we are one of six equal partners (BP 16.7%) in the NWS Venture. The joint venture operation covers offshore production platforms, a floating production and storage vessel, trunklines, onshore gas processing plants and LNG carriers. During 2004, a fourth LNG Train (capacity 4.2 million tonnes/191 bcf per annum) and a second trunkline were commissioned. A ninth LNG carrier was also commissioned during the year. NWS produced 9.3 million tonnes (424 bcf) of LNG, an increase of 15% on 2003.

In Indonesia, BP is involved in two of the three LNG centres in the country. Firstly, BP participates in Indonesia's LNG exports through its holdings in the Sanga-Sanga PSA (BP 38%). Sanga-Sanga delivered around 25% of the total gas feed to the Bontang LNG plant, the world's largest, in 2004. The Bontang plant produced 20 million tonnes (914 bcf) of LNG in 2004, a reduction of 3% on 2003.

Also in Indonesia, BP has interests in the Tangguh LNG joint venture (BP 37% and operator) and in each of the Wiriagar (BP 38% and operator), Berau (BP 48% and operator) and Muturi (BP 1%) PSAs in Northwest Papua that will supply feed gas to the Tangguh LNG plant. In March 2005, Tangguh received key government approvals for the launch of two trains and is now executing the major construction contracts, with start-up planned late in 2008. Tangguh is expected to be the third LNG centre in Indonesia, with an initial capacity of 7.6 million tonnes (388 bcf) per annum. Tangguh has signed sales contracts for delivery to China, Korea, and North America's West Coast.

In Trinidad, construction at the Atlantic LNG Train 4 (BP 37.8%) continued to proceed as planned and was estimated two-thirds complete at end 2004. Train 4 is designed to produce 5.2 million tonnes (253 bcf) per annum of LNG. BP expects to supply at least two thirds of the gas to the train. The facilities will be operated under a tolling arrangement, with the equity owners retaining ownership of their respective gas. The LNG is expected to be sold in the USA, Dominican Republic, and other destinations at the option of the owners. The project is on schedule for end 2005 start-up with the first LNG cargo scheduled for December 2005. BP's net share of the capacity of Atlantic LNG Trains 1, 2 and 3 is 4.5 million tonnes (212 bcf) of LNG per annum.

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. We operate primarily in Europe and North America, but also market our products across Australasia and in parts of Southeast Asia, Africa and Central and South America.

	Years ended December 31,		
	2004	2003	2002
		($ million)	
Turnover (a)	179,587	149,477	125,836
Total operating profit	6,084	2,483	1,969
Total assets	66,289	58,602	54,505
Capital expenditure and acquisitions	3,014	3,080	7,753
		($ per barrel)	
Global Indicator Refining Margin (b)	6.08	3.88	2.11

(a) Excludes BP's share of joint venture turnover of $594 million in 2004, $453 million in 2003, and $415 million in 2002.

(b) The Global Indicator Refining Margin is the average of six regional industry indicator margins which we weight 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. The refining margins are industry specific rather than BP specific measures, which we believe are useful to investors in analysing trends in the industry and their impact on our results. The margins are calculated by BP based on published crude oil and product prices and take account of fuel utilization and catalyst costs. No account is taken of BP's other cash and non-cash costs of refining, such as wages and salaries and plant depreciation. The indicator margin may not be representative of the margins achieved by BP in any period because of BP's particular refining configurations and crude and product slate.

There are four areas of business in Refining and Marketing: Refining, Retail, Lubricants and Business to Business Marketing. Our strategy is to continue our focused investment in key assets and market positions. In all areas, we aim for greater operational efficiency, and at the same time we seek to improve our asset portfolio. The acquisition of Veba's marketing and refining operations in 2002 provided an important addition to our operations, particularly in Germany.

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 major refiners of gasoline and hydrocarbon products in the USA, Europe and Australia. We have significant retail and business to business market positions in the USA, UK, Germany and the rest of Europe, Australasia, Africa and Southeast Asia and we are enhancing our presence in China and Mexico.

During the course of 2004, BP disposed of its one-third share of the Singapore Refining Company Private Limited, with one sixth being sold to each of Caltex Singapore Private Limited and Singapore Petroleum Company Limited. The sale was completed in June. The refinery had total crude distillation capacity of 248,000 barrels per day. BP also terminated refining operations at the ATAS Refinery in Mersin, south eastern Turkey. The site had a crude distillation capacity of 100,000 barrels per day and will continue to operate as a fuels terminal.

BP announced the sale of its 70% share in its Malaysia fuels business to 30% shareholder Lembaga Tabung Angkatan Tentera (LTAT). The business comprises 240 service stations, a modern fuel terminal and two joint-venture automated LPG bottling plants with turnover of $500 million and employs 250 staff. The transaction is expected to complete in the third quarter of 2005.

In July 2004 BP announced conditional agreement had been reached with Singapore Petroleum Company Limited (SPC) for sale of BP's retail and LPG business in Singapore. The retail business comprises 30 stations and associated business administration and the LPG business comprises BP's 70% shareholding in BP Wearnes Gas Ltd. The transaction was completed in the third quarter of 2004.

During 2003, divestments mandated in connection with the Veba transaction as a condition of regulatory approval of the deal were completed with the sale of a 45% stake in Bayernoil refinery, an 18% stake in the Trans Alpine Pipeline (TAL), 741 retail stations in Germany, 55 stations in Hungary and 11 in Slovakia in separate packages to PKN Orlen and OMV AG, for a total of $580 million in cash and assumption of debt.

Capital expenditure and acquisitions in 2004 was $3,014 million compared with $3,080 million in 2003 and $7,753 million in 2002 (including $5,038 million for the Veba acquisition). Excluding acquisitions, capital expenditure was $2,831 million in 2004 compared with $3,006 million in 2003 and $2,682 million in 2002. Capital expenditure excluding acquisitions is expected to be around $3.2 billion in 2005.

Resegmentation in 2005

Since the end of 2004, BP has made a number of organizational changes. With effect from January 1, 2005:

- The Grangemouth and Lavéra refineries were transferred from the Refining and Marketing segment to the Olefins and Derivatives (O&D) business.

- The Aromatics and Acetyls businesses and the Petrochemicals assets that are integrated with our Gelsenkirchren refinery in Germany will be part of Refining and Marketing.

- The Mardi Gras pipeline system in the Gulf of Mexico has been transferred from Exploration and Production to Refining and Marketing.

Texas City Refinery

On March 23, 2005, an explosion and fire occurred in the Isomerization Unit of the BP Texas City refinery as the unit was coming out of planned maintenance. Fifteen contractors involved in maintenance work died in the incident. Other contractors and employees were injured, some very seriously. The US Occupational Safety and Health Administration, the US Chemical Safety and Hazard Investigation Board and the Texas Commission on Environmental Quality, among others, are conducting investigations. BP has finalized or is in process of negotiating settlements in respect of fatalities and personal injury claims arising from the incident. BP currently expects that the total amount of these settlements will not be material to the Group's results of operations or financial position for the year 2005. However, such amount may be material to the Group's results of operations for a particular quarter.

Refining

The Company's global refining strategy is to own interests in and to operate advantaged refineries that provide distinctive returns through vertical integration with our marketing and trading operations and horizontal integration with other parts of the Group's business. Refining's focus is to maintain and improve competitive position through sustainable, safe, reliable and efficient operations of the refining system and disciplined investment for growth.

For BP, the strategic advantage of a refinery relates to the refinery's location, the refinery's scale and its configuration to produce fuels in line with the demand of the region from low-cost feedstocks. Efficient operations are measured primarily using regional refining surveys conducted by third parties. The surveys assess our competitive position against benchmarked industry measures for margin, energy efficiency and costs per barrel. Investments in our refineries are focused on maintaining our competitive position and developing the capability to produce the cleaner fuels that meet our customers' and the communities' requirements.

The following table summarizes the BP Group interests and crude distillation capacities at December 31, 2004:

			Crude distillation capacities (a) (mb/d)	
	Refinery	**Group interest (b) %**	**Total**	**BP Share**
UK	Coryton*	100.00	172	172
	Grangemouth*	100.00	207	207
Total UK			379	379
Rest of Europe				
France	Lavéra*	100.00	218	218
	Reichstett	17.00	84	14
Germany	Bayernoil	22.50	269	61
	Gelsenkirchen*	50.00	272	136
	Karlsruhe	12.00	308	37
	Lingen*	100.00	87	87
	Schwedt	18.75	221	41
Netherlands	Nerefco*	69.00	400	276
Spain	Castellón*	100.00	110	110
Total Rest of Europe			1,969	980
USA				
California	Carson*	100.00	260	260
Washington	Cherry Point*	100.00	232	232
Indiana	Whiting*	100.00	405	405
Ohio	Toledo*	100.00	155	155
Texas	Texas City*	100.00	470	470
Total USA			1,522	1,522
Rest of World				
Australia	Bulwer*	100.00	97	97
	Kwinana*	100.00	137	137
New Zealand	Whangerei	23.66	109	26
Kenya	Mombasa	17.00	91	16
South Africa	Durban	50.00	182	91
Total Rest of World			616	367
Total			4,486	3,248

*
Indicates refineries operated by BP.

(a)
Crude distillation capacity is gross rated capacity which is defined as the maximum achievable utilization of capacity (24-hour assessment) based on standard feed.

(b)
BP share of equity, which is not necessarily the same as BP share of processing entitlements.

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 summarized.

	Years ended December 31,		
Refinery throughputs (a)	**2004**	**2003**	**2002**
	(thousand barrels per day)		
UK	407	397	389
Rest of Europe	854	932	918
USA	1,373	1,386	1,439
Rest of World	342	382	357
	2,976	3,097	3,103
For BP by others			14
Total	2,976	3,097	3,117
Refinery capacity utilization			
Crude distillation capacity at December 31, (b)	3,248	3,408	3,534
Crude distillation capacity utilization (c)	92%	91%	91%
United States	95%	91%	93%
Europe	90%	90%	91%
Rest of World	87%	94%	85%

(a) Refinery throughput reflects crude and other feedstock volumes.

(b) Crude gross rated capacity is defined as the maximum achievable utilization of capacity (24 hour assessment) based on standard feed.

(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).

BP's 2004 refinery throughput decreased in the Rest of Europe compared with 2003 primarily due to the closure of operations at Mersin and the Bayernoil refinery divestment mandated in connection with the Veba acquisition. The decrease in Rest of World is primarily due to the disposal of BP's interests in Singapore Refining Company Private Limited (SRC). The decrease in the USA in 2004 was largely due to the impact of a fire at Texas City. BP's 2003 refinery throughput increased in the Rest of Europe compared with 2002, primarily due to higher margins. In 2002 lower margins required that many of the refineries reduce throughput. The decrease in the USA in 2003 was due to the sale of the Yorktown, Virginia refinery in May 2002, reducing capacity by 23 mb/d, and the balance was due to major turnaround activities in 2003 compared with 2002.

Marketing

Marketing comprises three business areas: Retail, Lubricants and Business to Business Marketing. 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.

Sales of refined products (a)	Years ended December 31, 2004	2003	2002
	(thousand barrels per day)		
Marketing sales:			
UK (b)	322	275	253
Rest of Europe	1,360	1,308	1,467
USA	1,682	1,766	1,874
Rest of World	638	620	586
Total marketing sales (c)	4,002	3,969	4,180
Trading/supply sales (d)	2,396	2,719	2,383
Total refined products	6,398	6,688	6,563
	($ million)		
Proceeds from sale of refined products	124,458	102,003	87,520

(a) Excludes sales to other BP businesses.

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

(c) Marketing sales are sales to service stations, end-consumers, bulk buyers, jobbers, i.e. third parties who own networks of a number of service stations and small resellers.

(d) 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	Years ended December 31, 2004	2003	2002
	(thousand barrels per day)		
Aviation fuel	494	530	529
Gasolines	1,675	1,714	1,744
Middle distillates	1,255	1,203	1,232
Fuel oil	343	296	451
Other products	235	226	224

	Years ended December 31,		
Total marketing sales	4,002	3,969	4,180

In marketing, our aim is to increase total margin by focusing on both volumes and margin per unit. We do this by growing our customer base, both in existing and new markets, by attracting new customers and by covering a wider geographic area. We also work to improve the efficiency of our operations through reducing the cost of goods sold and improving our product mix. 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 better able to meet these customer demands.

During the course of the year we have been successful in maintaining overall volumes despite rising oil and product prices and continuing competitive pressures.

BP's marketing sales volumes in 2004 were similar to those in 2003.

Retail

Our retail strategy is to focus our capital into the best locations in high growth metropolitan markets where we can be number one or two in market share, whilst continuing to upgrade our offers and drive for operational efficiencies.

There are two components of our retail offer: convenience and fuels. The convenience offer comprises sales of convenience items to customers from advantaged locations in metropolitan areas; whereas our fuel offer is deployed at service station locations in all our markets, in many cases without the convenience offer. We execute our convenience offer through a quality store format in each of our key markets, whether it is the BP Connect offer in Europe and the Eastern USA, the am/pm offer west of the Rocky Mountains in the USA, or the Aral offer in Germany. Each of these brands carries a very strong offer in itself, but we also aim to share best practices between them. Since 2003, we have also upgraded our fuel offer with the introduction of Ultimate gasoline and diesel products, which have greater efficiency and power and lesser environmental impacts. In 2004, we continued our roll-out of new generation Ultimate gasoline and diesel fuels, now available in the UK, Germany, Austria, Spain, Portugal, Greece, France, Poland, Australia and the US.

We also aim to focus on operational efficiencies through targeted programmes for performance improvement. These have allowed us to increase our fuel throughput per site and increase our store sales per square metre. We aim to increase site performance through fuel marketing and retailing efficiencies.

In 2004, across the network, our large format stores achieved store sales growth slightly above the market average. Total store sales, reflecting investment in new selling space, grew by 6%.

	Years ended December 31,		
Store sales (a)	**2004**	**2003**	**2002**
		($ million)	
UK	655	567	527
Rest of Europe	3,090	3,000	2,638
USA	1,715	1,620	1,585
Rest of World	601	521	421
Total	6,061	5,708	5,171
Direct managed	2,319	2,090	1,869
Franchise	3,623	3,508	3,216
Store alliances	119	110	86
Total	6,061	5,708	5,171

(a) Store sales reported are sales through direct-managed stations, franchises and the BP share of store alliances and joint ventures. Sales figures exclude sales taxes and lottery sales but include quick service restaurant sales. Fuel sales are not included in these figures.

Our retail network is largely concentrated in Europe and the USA, with established operations in Australasia, Southeast Asia and Southern & Eastern Africa. We are developing networks in China and Mexico.

BP's worldwide network consists of nearly 27,000 stations branded BP, Amoco, ARCO and Aral. We expect the total number of service stations carrying our brands to decline further in future years, reflecting the continued optimization of our retail network and efforts to increase the consistency of our site offer. We also continue to improve the efficiency of our retail asset network through a process of regular review. In July 2004, following a strategic review, we announced the divestment of our retail network in Singapore. This transaction was completed in the third quarter. In addition during 2004, further portfolio upgrading was achieved through the divestment of around a further 660 sites primarily due to underperformance.

In 2004, we continued the rollout of the BP Connect offer at sites in the UK and USA continuing our retail strategy that builds on our advantaged locations, strong market positions and brand. These are service stations with large convenience stores that provide our customers cleaner fuels, a wider range of services and a distinctive food offer. The new BP Connect sites include service stations that are new, those that have been rebuilt, and those where extensive upgrading and remodeling has taken place. At December 31, 2004, nearly 600 BP Connect stations were open. In addition, the number of stores with the new BP Helios design increased by about 3,100 during 2004 to a total of around 19,800.

At December 31, 2004, BP's retail network in the USA comprised approximately 14,200 service stations, of which approximately 10,300 were owned by jobbers. Through regular review and execution of business opportunities we are continuing to concentrate our ownership of real estate in markets designated for development of the convenience offer. In the USA, we increased the number of stations with the new BP Helios design by approximately 2,300 in 2004.

In the UK and the Rest of Europe, BP's network comprised about 9,300 service stations at December 31, 2004. During the year we opened 60 BP Connect sites in Europe with the majority being in metropolitan areas of the UK. The number of stations throughout Europe that use the new BP Helios design was about 6,400 by the end of 2004.

At December 31, 2004, BP's retail network in the rest of the world comprised some 3,300 service stations. Our established networks are primarily in Australia, New Zealand, Southern Africa and Southeast Asia. During 2004, BP China and Sinopec announced the establishment of the BP-Sinopec (Zhejiang) Petroleum Co. Ltd., a retail joint venture between BP and Sinopec. Based on the existing service station network of Sinopec, the new joint venture has plans to build, operate and manage a network of 500 service stations in Hangzhiou, Ningbo and Shaoxing. Also during the year, BP China and PetroChina announced the establishment of BP-PetroChina Petroleum Company Limited. Located in Guangdong, one of the most developed provinces in China, the joint venture is intended to acquire, build, operate and manage 500 service stations in the province. The initial investment in both joint ventures amounted to $106 million.

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 margin sectors of automotive lubricants, especially in the consumer sector, but also has a strong presence in business markets such as commercial vehicle fleets, aviation, marine and specialized industrial segments.

We aim to achieve growth by further focusing our resources and capabilities on selected market sectors. Customer focus, distinctive brands and superior technology remain the cornerstone of our long-term strategy.

BP markets through its two major brands, Castrol and BP, and several secondary brands including Duckhams and Veedol. The Veba acquisition in 2002 strengthened our lubricants position in Germany and in Central Europe with the addition of the Aral brand to the BP Lubricants portfolio.

In the consumer sector of the automotive segment we supply lubricants, other products and related business services to intermediate customers (e.g., retailers, workshops) who in turn serve end-consumers (e.g., car, motorcycle, leisure craft owners) in the mature markets of Western Europe and North America and also in the fast growing markets of the developing world (e.g., Russia, China, India, Middle East, South America and Africa). The Castrol brand is recognized worldwide and we believe it provides us with a significant competitive advantage.

In commercial vehicle and general industrial markets we supply lubricants and lubricant-related services to the transportation industry and to automotive manufacturers.

Business to Business Marketing

Business to Business Marketing encompasses marketing a comprehensive range of products to other businesses. This business aims to build relationships with customers that not only purchase a wide variety of products in large quantities but also additional services. Interfaces with Retail, Refining and Logistics play a crucial role in this 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.

Air BP is one of the world's largest aviation businesses supplying aviation fuel and lubricants to the airline, military and general aviation sectors. It supplies customers in approximately 100 countries, has annual sales of around 24 million tonnes (approximately 500,000 bbl/day) and has key relationships with most of the major commercial airlines. Our strategic aim is to strengthen our position in our existing markets (Europe/US/Asia Pacific) whilst creating opportunities in the emerging economies such as South America, China, Russia and Ukraine.

The LPG businesses sell bulk, bottled, automotive and wholesale products to a wide range of customers in over 19 countries. During the past few years, our LPG business has strengthened its position in established markets, pursued opportunities in new and emerging markets and rationalized its operations. During 2004, BP remained the leading importer of LPG into the China market, where we continued to grow our business. LPG Product sales in 2004 were nearly 3.4 million tonnes (approximately 100,000 bbl/day).

Marine comprises three global businesses: Marine Fuels, Marine Lubricants, and Power Generation and Offshore, which supplies specialist lubricants to the power generation and offshore industry. Under the BP and Castrol brands, the business is the lubricants market leader and has a strong trading and bunker presence in the fuels market. The business has offices in 40 countries and operates in over 800 ports.

The Wholesale and Reseller business has activities in 11 European countries, has annual sales of 27.5 million tonnes (approximately 530,000 bbl/day) and employs nearly 250 people. The business markets fuels and heating oil, mostly as pick-up business at refineries, terminals and depots.

Our Business to Business Marketing activities also include Industrial Lubricants (selling industrial lubricants and services to manufacturing companies in approximately 40 countries), European Fleet Services (serving commercial road transport customers in 12 countries), and the supply of bitumen to the road and roofing industries. The business seeks to increase value by building from the technology, marketing and sales capabilities of a business to business operation.

Supply and Trading

The Group has a long established supply and trading activity responsible for delivering value across the overall crude and oil products supply chain. This activity identifies the best markets and prices for our crude oil, sources optimal feedstock to our refining assets and sources marketing activities with flexible and competitive supply. Additionally, the function creates incremental trading gains through holding commodity derivative contracts and trading inventory. To achieve these objectives in a liquid and volatile international market the Group enters into a range of commodity derivative contracts including exchange traded futures and options, over-the-counter options, swaps and forward contracts as well as physical term and spot contracts.

Exchange traded contracts are traded on liquid regulated markets which transact in key crude grades, such as Brent and West Texas Intermediate and the main product grades such as gasoline and gasoil. These exchanges exist in each of the key markets in the US, Western Europe and Far East. Over-the-counter contracts include a variety of options and most importantly swaps. These swaps price in relation to a wider set of grades than those traded through the exchanges where counterparties contract for differences between, for example, fixed and floating prices. The contracts we use are described in more detail below. Additionally, physical crude can be traded forward by using specific over-the-counter contracts pricing in reference to Brent and West Texas Intermediate grade. Over-the-counter crude forward sales contracts are used by BP to both buy and sell the underlying physical commodity as well as a risk management and trading instrument. The scale and application of these over-the-counter forward contracts, when measured by volume, has not changed significantly over the period 2002 to 2004. The volumes of crude oil sold through over-the-counter forward sales contracts was 1,276 mb/d in 2002, 1,284 mb/d in 2003 and 1,303 mb/d in 2004. The turnover associated with these contracts increased as a function of the increasing price of crude oil over the period.

Risk management is undertaken when the Group is exposed to market risk primarily due to the timing of sales and purchases, which may occur for both commercial and operational reasons. For example, if the Group has delayed a purchase and has a lower than normal inventory level, the associated price exposure may be limited by taking an offsetting position in the most suitable commodity derivative contract described above. Where trading is undertaken, the Group actively combines a range of derivative contracts and physical positions to create incremental trading gains by arbitraging prices, typically between locations and time periods. This range of contract types includes futures, swaps, options and forward sale and purchase contracts, these contracts are described further below. The nature and purpose of this activity is broadly unchanged, though the volume of activity has grown slightly over the period 2002 to 2004.

Through these transactions the Group sells crude production into the market allowing more suitable higher margin crude to be supplied to our refineries. The Group may also actively buy and sell crude on a spot and term basis to further improve selections of crude for refineries. In addition, where refinery production is surplus to marketing requirements or can be sourced more competitively, it is sold into the market. This latter activity also encompasses opportunities to maximise the value of the whole supply chain through the optimisation of storage and pipeline assets including the purchase of product components that are blended into finished products. The Group also owns and contracts for storage and transport capacity to facilitate this activity.

The range of transactions that the Group enters into is described below in more detail:

(a)

Exchange traded commodity derivatives

These contracts are typically in the form of futures and options traded on a recognised Exchange, such as Nymex, Simex, IPE and Chicago Board of Trade. Such contracts are traded in standard specifications for the main marker crude oils such as Brent and West Texas Intermediate and the main product grades such as gasoline and gasoil. Though potentially settled physically, these contracts are typically settled financially. Gains and losses, otherwise referred to as variation margins, are settled on a daily basis with the relevant Exchange. These contracts are used for the trading and risk management of both crude and products. Realized and unrealized gains and losses on exchange traded commodity derivatives are included in cost of sales for UK GAAP and within revenues for US GAAP.

(b)

Over-the-counter (OTC) contracts, excluding forward contracts

These contracts are typically in the form of swaps and options. OTC contracts are negotiated between two parties. They are not traded on an Exchange. Amounts are settled at expiry, typically through netting agreements, to limit credit exposure and support liquidity. Swaps are contractual obligations to exchange cash flows between two parties, one usually references a floating price whilst the other a fixed price with the net difference of the cash flows being settled. Options give the holder the right but not the obligation to buy or sell crude or oil products at a specified price on or before a specific future date. These contracts can be used both as part of trading and risk management activities. Realized and unrealized gains and losses on OTC contracts (other than forward contracts) are included in cost of sales for UK GAAP and within revenues for US GAAP.

(c)

Over-the-counter forward contracts

West Texas Intermediate and a standard North Sea crude blend (Brent, Forties and Osberg BFO) are bought and sold forward using standard contracts. These contracts are negotiated between two parties and not traded on an Exchange. Although they specify physical delivery terms for each crude blend a significant volume are not settled physically. The contracts contain standard delivery, pricing and settlement terms. Additionally the BFO contract specifies a standard volume and tolerance given the physically settled transactions are delivered by cargo. For UK GAAP, OTC forward sales contracts are included in turnover when settled and OTC forward purchase contracts are included in cost of sales when settled. Unrealized gains and losses are included in cost of sales. For US GAAP, where OTC forward contracts are held for trading, realized and unrealized gains are included in revenues.

(d)

Spot and term contracts

Spot contracts are contracts to purchase or sell crude and oil products at the market price prevailing on and around the delivery date. Term contracts are contracts to purchase or sell a commodity at regular intervals over an agreed term. Though spot and term contracts may have a standard form, there is no offsetting mechanism in place. Spot transactions price around the bill of lading date when we take title to the inventory. These transactions result in physical delivery with operational and price risk. Spot and term contracts relate typically to purchases of crude for a refinery, sales of the Group's oil production and sales of the Group's oil products. For UK and US GAAP, spot and term sales are included in turnover and revenues respectively, when title passes. Similarly, spot and term purchases are included in cost of sales for UK and US GAAP.

The following table describes how these types of transactions contributed to turnover over the period 2002 to 2004:

		Years ended December 31,		
		2004	**2003**	**2002**
Sale of crude oil through spot and term contracts	($ million)	25,027	23,915	18,150
Sale of crude oil, through over-the-counter forward contracts	($ million)	18,485	14,098	11,599
Marketing, spot and term sales of refined products	($ million)	124,458	102,003	87,520
Other sales including non-oil and to other segments	($ million)	11,617	9,461	8,567
		179,587	149,477	125,836
Sale of crude oil through spot and term contracts	(mb/d)	2,505	2,553	2,659
Sale of crude oil, through over-the-counter forward contracts	(mb/d)	1,303	1,284	1,276
Marketing, spot and term sales of refined products	(mb/d)	6,398	6,688	6,563

Refer to Item 5 Operating and Financial Review Refining and Marketing on page 91 and Item 11 Quantitative and Qualitative Disclosures About Market Risk on page 168 for further information.

Transportation

Our Refining and Marketing business owns, operates or has an interest in extensive transportation facilities for crude oil, refined products and petrochemical feedstock in the US.

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

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 major product pipelines in the UK, the Rest of Europe and in the US.

Shipping

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

Excluding BP companies in the USA, at December 31, 2004 BP Shipping managed an international fleet of 34 oil tankers (comprising four very large crude carriers, 29 medium sized crude carriers and one North Sea shuttle tanker) and eight LNG ships with capacity of approximately 4.8 million cubic metres (comprising three trading globally, four for Abu Dhabi contracted gas and one for the Western Australia NWS Project). In addition, BP holds an interest in a further six NWS LNG carriers. BP also owned two UK coastal tankers.

These ships are manned either by BP Maritime Services personnel or by third party manning contractors who operate to BP Shipping's standards and reporting requirements. All the chartering of ships is controlled by BP Shipping, and the ships are utilized to carry either BP cargoes or third party cargoes.

BP Shipping is in the middle of a new building programme, which saw 12 leased ships delivered into service in 2004.

BP companies in the USA had one large crude carrier, six medium crude carriers, and one product carrier totalling approximately 0.7 million dead weight tonnes (dwt) on long-term charter. BP owns four barges totalling 0.1 million dwt and took delivery of the first of four state-of-the-art double-hulled 1.3 million barrel Alaskan Class tankers from National Steel and Shipbuilding Company of San Diego, California during the year.

PETROCHEMICALS

Our petrochemicals businesses produce chemicals and plastics through subsidiaries, joint ventures and associated undertakings. The petrochemicals businesses are also responsible for the supply, marketing and distribution of chemical products to bulk, wholesale and retail customers. BP has operations principally in the USA and Europe. We are increasing our activities in the Asia-Pacific region.

	Years ended December 31,		
	2004	2003	2002
	($ million)		
Turnover (a)	21,209	16,075	13,064
Total operating profit	12	585	447
Total assets	18,877	16,677	15,783
Capital expenditure and acquisitions	2,289	775	823
	($/tonne)		
Chemicals Indicator Margin (b)	140	112	104

(a) Excludes BP's share of joint venture turnover of $462 million in 2004, $434 million in 2003 and $511 million in 2002.

(b) The Chemicals Indicator Margin (CIM) is a weighted average of externally based industry product margins. It is based on market data collected by Nexant in their quarterly market analyses, which we weight 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 (LAOs), acetic acid, vinyl acetate monomers and nitriles. Not included are fabrics and fibres, poly alpha-olefins (PAOs), anhydrides, speciality intermediates and the remaining parts of the solvents and acetyls businesses. CIM is an environmental trend indicator. Changes in CIM are indicative of market environment trends rather than representative of the actual margins achieved by BP in any particular period.

We are now managing our portfolio in two distinct parts Aromatics and Acetyles (A&A), comprising PTA, PX and acetic acid, and Olefins and Derivatives, (O&D) comprising principally ethylene and related co-products, polypropylene, HDPE and acrylonitrile. We intend to retain and grow the A&A businesses, which were transferred to the Refining and Marketing segment on January 1, 2005. The Petrochemical facilities of BP Refining and Petrochemicals (BPRP) at Gelsenkirchen and Munchmunster in Germany will also remain with BP and were transferred to the Refining and Marketing segment on January 1, 2005 along with the following other petrochemical products: Napthalene dicarboxylate (NDC), vinyl acetate monomer (VAM) and ethyl acetate.

In April 2004, we announced our intention to set up a separate corporate entity for the O&D businesses. It is our intention to divest this O&D entity, possibly starting with an initial public offering in the second half of 2005, subject to market conditions and the receipt of necessary approvals. In November 2004, we announced our intention to include two European oil refineries in the new O&D entity. The refineries at Grangemouth, UK and Lavéra, France, are closely integrated with their neighbouring chemicals plants which take refinery products as feedstock. The following other petrochemical products are also included within the new O&D entity: linear low density polyethylene (LLDPE), low density polyethylene (LDPE), ethylene oxide, ethanol, LAO, PAO, polybutene and styrene monomer and polymer. The new O&D entity is called Innovene and was formed as a separate entity within the BP Group in April 2005. Innovene is being reported within Other Businesses and Corporate from January 1, 2005.

Our core products are eventually used in the manufacture of a wide variety of consumer goods, including plastic drinks bottles, computer housings, adhesives, inks, rigid packaging, pipes, food packaging and automobile components. We compete through proprietary technology, leadership positions and value associated with the integration of Group hydrocarbons and sites. Our investment and divestment activities are aligned with this strategy.

Significant investment activities during 2004:

In May, we signed a Heads of Agreement to build a 500 kilotonnes per annum (ktepa) acetic acid plant in Nanjing, Jiangsu province in China, through a 50/50 joint venture with Sinopec. In March 2005, a joint venture contract was signed with Sinopec to build this plant in Nanjing. Completion of the plant is expected in 2007.

In May, we signed a Letter of Intent to examine the viability of expanding production at the BP Zhuhai PTA plant from 350 ktepa to 1,200 ktepa. The plant, which is located at Zhuhai in the Pearl River Delta, is a joint venture between BP (85%) and Fu Hua Group (15%) and came on stream in September 2003.

BP increased its ownership in CAPCO, our PTA joint venture in Taiwan. BP acquired an incremental 2% interest in CAPCO to attain a total equity share of 61%.

In November, Solvay exercised its option to sell its interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America to BP. The BP Solvay ventures, established in 2001, comprise HDPE business interests and manufacturing sites in Europe and the USA with a total capacity of 2.6 million tonnes.

The Shanghai Ethylene Cracker Complex (SECCO), a petrochemical joint venture in Shanghai, China between BP, Sinopec Corporation and Sinopec Shanghai Petrochemical Company, (BP 50%), was declared mechanically complete in December 2004. Completion of start-up occured during the second quarter of 2005. SECCO is an integrated Olefins and Derivatives site with a naphtha fed ethylene cracker and a number of downstream derivative sites.

In November, BP and Nova Chemicals Corporation (Nova) announced that they had reached agreement in principle to combine their European interests in Styrene polymers to create one of the largest polystyrene and expandable polystyrene manufacturers and marketers in Europe. BP and Nova will each have a 50 per cent stake. BP's European interests in Styrene polymers includes plants operating at Marl in Germany, Wingles in France and Trelleborg in Sweden. In May 2005, binding agreements were signed. Operations are expected to commence in the third quarter of 2005.

Capital expenditure and acquisitions in 2004 was $2,289 million compared with $775 million in 2003 and $823 million in 2002. Excluding acquisitions, capital expenditure was $934 million, $775 million and $810 million respectively. 2004 includes $1,355 million for the acquisition of Solvay's interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America.

Significant divestment activities during 2004:

In February, we announced the closure of the last manufacturing plant at Baglan Bay, UK. Production of isopropanol ceased in March 2004.

In May, we completed the sale of our wholly owned specialty intermediate chemicals businesses including trimellitic anhydride (TMA), purified isophthalic acid (PIA) and maleic anhydride (MAN).

In October, we completed the sale of our Fabrics and Fibres Business.

In November, we announced a phased exit from two, old technology, acetic acid and acetone manufacturing operations at Hull, UK. One unit closed at the end of April 2005 and the other is scheduled to close in late 2006/early 2007. These closures will lead to a phased withdrawal from formic acid, proprionic acid and acetone businesses and a reduction in our European acetic acid production capacity.

In November, we announced the closure of a High Density Polyethylene manufacturing operation at Grangemouth, UK.

In December, we announced that we would close our LAO production facility in Pasadena, Texas, by the end of 2005. The Company will continue to produce LAOs at its other two facilities in Alberta, Canada and Feluy, Belgium. Closure of the Pasadena site will reduce BP's global linear alpha olefins capacity by 485 ktepa.

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 (3,045 ktepa) and Hull (1,535 ktepa) in the UK; Lavéra (1,940 ktepa) in France; Marl (635 ktepa), Gelsenkirchen (1,455 ktepa) and Köln (4,615 ktepa) in Germany; Geel (2,045 ktepa) in Belgium; and Texas City, Texas (2,850 ktepa), Chocolate Bayou, Texas (2,705 ktepa), Decatur, Alabama (2,250 ktepa), and Cooper River, South Carolina (1,335 ktepa) in the USA.

We aim to grow in the Asia-Pacific region, which we believe offers good prospects for demand growth. Our 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 4,775 ktepa, as follows: Indonesia (245 ktepa), South Korea (1,020 ktepa), Malaysia (1,505 ktepa), Taiwan (1,250 ktepa) and China (755 ktepa). When on line in 2005, our share of the SECCO petrochemical complex in Shanghai, (BP 50%), is expected to add 1,700 ktepa of capacity.

	Years ended December 31,		
Production by region (a)	**2004**	**2003**	**2002**
		(ktepa)	
UK	3,328	3,186	3,221
Rest of Europe	10,990	10,958	10,526
USA	10,204	9,797	9,934
Rest of World	4,405	4,002	3,307
Total Production (a)	28,927	27,943	26,988

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

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.

During 2004, overall BP petrochemicals production capacity grew 3%.

The following table shows BP production capacity (ktepa) by product and by region at December 31, 2004. This production capacity is based on original design capacity of the plants plus expansions.

Capacity by region (a)	UK	Rest of Europe	USA	Rest of World	Total
PTA		1,033	2,440	3,668	7,141
PX		501	2,350		2,851
Acetic acid	810		523	936	2,269
Ethylene and related co-products	1,592	4,263	2,315	66	8,236
Polypropylene	273	1,075	1,386		2,734
HDPE	252	1,153	1,031	185	2,621
Acrylonitrile/Acetonitrile		301	795		1,096
Other	1,654	4,880	1,601	301	8,436
Total	4,581	13,206	12,441	5,156	35,384

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

Aromatics and Acetyls

Purified Terephthalic Acid

PTA is important as a raw material for the manufacture of polyester used in textiles, fibres and films. BP is the world's largest producer of PTA, with an interest in approximately 20% 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 BP Zhuhai (BP 85%), Samsung Petrochemical Company (SPC) in South Korea (BP 47.41%), CAPCO in Taiwan (BP 61.43%), PT AMI in Indonesia (BP 50%) and Rhodiaco in Brazil (BP 49%). The sites in Taiwan, South Korea, Belgium and the USA are among the largest PTA production sites in the world.

Major Activities

- In May 2004, BP signed a letter of intent to examine the viability of expanding production at the BP Zhuhai (BP 85%) PTA plant from 350 ktepa to 1,200 ktepa.
- In December 2004, SPC (BP 47%) completed a 200 ktepa expansion at Soesan, South Korea.
- In December 2004, we increased our share in the CAPCO joint venture by 2.4% to 61.4%.

Paraxylene

PX is feedstock for the production of PTA and is manufactured from mixed xylene streams acquired from BP refineries and third-party producers. We are currently one of the world's leading producers of PX in terms of capacity. Our plants are located in Decatur, Alabama and Texas City, Texas in the USA and Geel in Belgium. We engage with Refining and Marketing to optimize sourcing of xylenes feedstock from BP refineries.

Acetic Acid

We are a major manufacturer and supplier of acetic acid, a versatile chemical used in a variety of products such as foodstuffs, textiles, paints, dyes and pharmaceuticals. Acetic acid is also used in the production of PTA. BP has acetic acid operations at Hull, UK; in the USA through a capacity rights agreement with Sterling Chemicals at Texas City, Texas; in South 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%).

Major Activities

The joint venture project to build a 300-ktepa acetic acid plant in Taiwan with Formosa Chemicals and Fibre Corporation (BP 50%) is on schedule with commissioning expected to take place around mid 2005.

Expansion of Yangtze River Acetyls Company, China to 350 ktepa is on track for completion during the third quarter of 2005.

BP has a 50% interest in a newly proposed 500-ktepa acetic acid plant in Nanjing, China. The Heads of Agreement was signed in May 2004, and a joint venture contract was signed in March, 2005. Completion of the plant is projected at the end of 2007.

BP has announced the phased closure of two Acetic Acid plants with combined capacity of 250 ktepa at Hull, UK. The first plant was shut down in the second quarter of 2005 and the remaining plant will be shut down in late 2006/early 2007.

Other Products

In addition to the above A&A products, we are involved in a number of other petrochemicals products which we also transferred to the Refining and Marketing segment on January 1, 2005. PIA is used for isopolyester resins and gel coats. NDC is used for photographic film and specialized packaging. Ethyl acetate and VAM are used in coatings and textile applications.

NDC is produced at our plant in Decatur, Alabama in the USA.

In South Korea, the Asian Acetyls Company (BP 34%) operates a 150-ktepa plant producing VAM, a derivative of acetic acid.

BP operates ethyl acetate and VAM plants at Hull in the UK. The Yantze River Acetyls Company also operates an ethyl/butyl acetate plant.

Olefins and Derivatives

Ethylene (and Related Co-products)

We produce and market the basic petrochemical building blocks, known as olefins, that are used primarily as raw material for other chemical products. These olefins are derived from the steam cracking of liquid and gaseous hydrocarbons.

Olefins ethylene, propylene and butadiene are produced by crackers at Grangemouth, UK; Lavéra, France (Naphtachimie BP 50%); Köln, Germany and Chocolate Bayou, Texas in the USA. Olefins are also manufactured by Ethylene Malaysia Sdn. Bhd. (BP 15%) at Kertih, Malaysia and by BPRP at Gelsenkirchen and Munchmunster in Germany. 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.

Major Activities

The construction and commissioning of the 900-ktepa ethylene cracker complex in Shanghai by SECCO (BP 50%) has progressed smoothly. By end 2004, construction was declared mechanically complete and completion of start-up occured during the second quarter of 2005.

In the USA, construction on the project to increase ethylene capacity at Chocolate Bayou, Texas by 295 ktepa was completed in the second quarter of 2005.

Polypropylene

Polypropylene is used for moulded products, fibres and films. Polypropylene resins are also converted into woven and non-woven fabrics for industrial products, such as carpet backing, geotextiles and various packaging materials. We have manufacturing facilities at Chocolate Bayou and Deer Park, Texas and Carson City, California in the USA; Lillo and Geel, Belgium; Lavéra and Sarralbe, France and Grangemouth, UK.

Major Activities

The SECCO petrochemicals complex in Shanghai (BP 50%), is expected to add 250 ktepa of polypropylene capacity when completed in 2005.

High Density Polyethylene

Polyethylene is used for packaging, pipes and containers. BP has HDPE plants at Grangemouth, UK; Lillo, Belgium; Sarralbe and Lavéra, France; and Rosignano, Italy. In addition, BP has a HDPE plant at Deer Park, Texas and a joint venture plant with Chevron Philips Chemical Company at Cedar Bayou, Texas. We also produce HDPE through Polyethylene Malaysia Sdn. Bhd. (BP 60%) at Kertih, Malaysia.

Major Activities

In November 2004, Solvay exercised its option to sell its interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America to BP. BP took effective control of these entities and consolidated them from November 2004.

The closure of a High Density Polyethylene manufacturing operation at Grangemouth, UK was announced in November.

The SECCO petrochemical complex in Shanghai (BP 50%), is expected to add 600 ktepa of HDPE/LLDPE capacity when completed in 2005.

Acrylonitrile

BP is the world's largest producer and marketer of acrylonitrile, which is used in textiles and plastics for the automobile and consumer goods industries. We operate two acrylonitrile plants at Green Lake, Texas and Lima, Ohio in the USA. Acrylonitrile is also produced at Köln, Germany and through a capacity rights agreement with Sterling Chemicals at Texas City, Texas.

Major Activities

The SECCO petrochemical complex in Shanghai (BP 50%) is expected to add 260 ktepa of acrylonitrile capacity when complete in 2005.

Other Products

In addition to the above products, we are involved in a number of other petrochemicals products which we are including within the new O&D entity. These include LLDPE and LDPE which are used in a wide range of applications including packaging, as is styrene. Ethylene oxide and ethanol are used in solvents, coatings and the automotive industry. LAOs are used as comonomers for polyethylenes and to manufacture synthetic lubricants, plasticizers, surfactants and oilfield chemicals. PAOs are used in both

synthetic lubricants and surfactants. Polybutene is used in lubricants and fuel additives. Butanediol (BDO) is used in synthetic materials and engineering plastics.

BP operates LLDPE plants at Grangemouth in the UK and Köln in Germany. The complex at Köln also produces LDPE.

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

BP manufactures polybutene at Whiting, Indiana in the USA and at Lavéra, France.

LAOs are produced at our facilities in Pasadena, Texas in the USA; Joffre, Canada and Feluy, Belgium. We manufacture PAOs at our facilities in Deer Park, Texas in the USA and Feluy, Belgium.

We manufacture BDO using our proprietary technology in a world-scale plant at Lima, Ohio in the USA. This plant was sold in March 2005.

Major Activities

We have implemented or announced a number of structural changes that we believe should significantly improve our portfolio. The most significant changes were as follows:

In February 2004, we announced the closure of the last manufacturing plant at Baglan Bay, UK. Production of isopropanol ceased in March 2004.

In May 2004, we completed the sale of our wholly owned specialty intermediate chemicals businesses including TMA, PIA and MAN.

In October 2004, we completed the sale of our Fabrics and Fibres Business.

In December 2004, we announced that we would close our LAO production facility in Pasadena, Texas, by the end of 2005.

In March 2005, we completed the sale of our BDO facility at Lima, Ohio.

GAS, POWER AND RENEWABLES

The strategic purpose of the Gas, Power and Renewables segment comprises 3 elements:

i. To capture distinctive world-scale market positions ahead of supply.

ii. To expand gross margin by providing distinctive products to selected customer segments and optimizing the gas and power value chains.

iii. To build a sustainable solar business and continue to assess the application of renewable and alternative energy sources.

The segment is organized into four main activities: marketing and trading; natural gas liquids (NGL); new market development and LNG; and solar and renewables. As previously reported, on January 1, 2004, a number of worldwide NGL producing assets were transferred to Gas, Power and Renewables from the Exploration and Production segment in order to consolidate the management of our global NGL activity. The transferred assets included seven gas processing plants, six of which are located in the mid-continent of the United States in the Permian, Anadarko and Hugoton basins, and one in Northern Europe as well as the BP partnership interest in the construction of a gas processing plant, NGL storage and export facilities in Egypt. The 2003 and 2002 data below has been restated to reflect this transfer.

	Years ended December 31,		
	2004	**2003**	**2002**
		($ million)	
Turnover	83,320	65,639	37,580
Total operating profit	926	582	469
Total assets	17,069	10,607	7,243
Capital expenditure and acquisitions	538	441	448

We seek to maximize the value of our gas by targeting higher value customer segments in selected markets and to optimize supply around our physical and contractual rights to assets. Marketing and trading activities are focused on the relatively open and deregulated natural gas and power markets of North America, the United Kingdom and certain parts of continental Europe. Some small elements of long-term natural gas contracting activity are also still included within the Exploration and Production business segment because of the nature of gas markets and the long-term sales contracts.

Our NGLs business is engaged in the processing, fractionation and marketing of ethane, propane, butanes and pentanes extracted from natural gas. Our NGL activity is underpinned by our upstream asset base and serves third-party markets for both chemicals and clean fuels and also supplies BP's petrochemicals and refining activities.

New market development and LNG activities involve developing opportunities to capture sales for our upstream natural gas resources and are conducted in close collaboration with the Exploration and Production business. Our strategy is to capture a greater share of the growth in the international demand for natural gas and is focused on markets which offer significant prospects for growth. These include the USA, Canada, UK, Spain and many of the emerging markets of the Asia Pacific region, notably China, where we believe there could be substantial growth in demand. For our undeveloped gas resources, we believe the key is to gain markets ahead of supply with a longer-term aim of allowing natural gas resources to move into the market with the same ease that oil does today. Our LNG activities involve the marketing of BP and third-party LNG.

Our solar and renewables activities include the development, production and marketing of solar panels and the development of wind farms on certain Group sites.

Other activities include gas-fired power generation projects, where our principal focus is on projects that will utilize our equity natural gas. Projects that will reduce Group power costs and/or reduce overall emissions are also a key focus area.

Capital expenditure and acquisitions for 2004 was $538 million compared with $441 million in 2003 and $448 million in 2002. Excluding acquisitions, capital expenditure for 2004, 2003 and 2002 was $538 million, $441 million and $375 million, respectively. Capital expenditure excluding acquisitions for 2005 is planned to be around $300 million; the reduction versus the 2004 level is due to lower spending on the Guangdong terminal in China, the power project in Korea and payments for the construction of new LNG ships.

	Years ended December 31,		
Group gas sales volumes (a)	**2004**	**2003**	**2002**
	(million cubic feet per day)		
UK (b)	4,679	6,801	5,603
Rest of Europe	411	441	399
USA	13,384	11,528	9,315
Rest of World	13,216	11,669	9,535
Total (c)	31,690	30,439	24,852
(a) Includes marketing, trading and supply sales. Also includes the following volumes under OTC forward contracts.	22,776	20,635	15,012

(b) UK volumes for 2003 and 2002 have been restated to include trading volumes consistent with other volumes presented in this table.

(c) Included in the above are sales made directly by the Exploration and Production segment to third parties. In 2004, these were 3.7 bcf/d, of which 2.7 bcf/d are in Rest of World.

Our policy toward natural gas price risk is described in Item 11 Quantitative and Qualitative Disclosures about Market Risk on page 173.

The following table describes how these types of transactions contributed to turnover over the period 2002 to 2004:

		Years ended December 31,		
		2004	**2003**	**2002**
Gas marketing sales	($ million)	13,532	12,929	9,401
Sale of gas through over-the-counter forward contracts	($ million)	43,099	32,338	14,049
Sale of power through over-the-counter forward contracts	($ million)	16,110	11,950	8,138
Sale of NGLs through over-the-counter forward contracts	($ million)	2,251	416	40
Other sales (including NGL marketing)	($ million)	8,328	8,006	5,952
	($ million)	83,320	65,639	37,580
Gas marketing sales volumes	(mmcf/d)	5,244	5,881	5,840
Natural gas sales by Exploration and Production	(mmcf/d)	3,670	3,923	4,000
Sale of gas through over-the-counter forward contracts	(mmcf/d)	22,776	20,635	15,012
Total natural gas sales volumes	(mmcf/d)	31,690	30,439	24,852

		Years ended December 31,		
Sale of power through over-the-counter forward contracts	(gwh/d)	1,162	1,012	650
Sale of NGLs through over-the-counter forward contracts	(mb/d) 63	188	32	3

Marketing and Trading Activities

Gas and power trading and marketing activity is undertaken in the US, Canada and the UK to dispose of BP's gas and power production, manage market price risk, supply marketing customers as well as create incremental trading gains through the use of commodity derivative contracts. Additionally, this activity generates fee income and enhanced margins from sources such as the management of price risk on behalf of third party customers. These markets are large, liquid and volatile and the Group enters into these transactions on a large scale to meet these objectives.

In connection with the above activities, the Group uses a range of commodity derivative contracts and storage and transport contracts. These include commodity derivatives such as futures, swaps and options to manage price risk and forward contracts used to buy and sell gas and power in the market place. Using these contracts in combination with rights to access storage and transportation capacity allows the Group to access advantageous pricing differences between locations, time periods and arbitrage between markets. Gas futures and options are traded through exchanges whilst over-the-counter options and swaps are used for both gas and power transactions through bilateral arrangements. Futures and options are primarily used to trade the key index prices such as Henry Hub, whilst swaps can be tailored to price with reference to specific delivery locations where gas and power can be bought and sold. Over-the-counter forward contracts have evolved in both the US and UK markets enabling gas and power to be sold forward in a variety of locations and future periods. These contracts are used to both sell production into the wholesale markets and as trading instruments to buy and sell gas and power in future periods. The contracts we use are described in more detail below. Capacity contracts allow the Group to store, transport gas and transmit power between these locations. Additionally, activity is undertaken to risk manage power generation margins related to the Texas City co-generation plant using a range of gas and power commodity derivatives

Our gas marketing and trading activities are concentrated primarily in the markets of North America and the United Kingdom. Gas sales volumes have increased from 24.9 billion cubic feet per day (bcf/d) in 2002 to 30.4 bcf/d in 2003 and 31.7 bcf/d in 2004. Most of this growth was realized in the USA and Canada, a trend expected to continue in the near term. Canada volumes are reported in the Rest of World volumes.

The range of transactions that the Group enters into is described below in more detail:

(a) Exchange traded commodity derivatives

Exchange traded commodity derivatives include gas and power futures contracts. Though potentially settled physically, these contracts are typically settled financially. Gains and losses, otherwise referred to as variation margins, are settled on a daily basis with the relevant Exchange. Realized and unrealized gains and losses on exchange traded commodity derivatives are included in cost of sales for UK GAAP and within revenues for US GAAP.

(b) Over-the-counter (OTC) contracts, excluding forward contracts

These contracts are typically in the form of swaps and options. OTC contracts are negotiated between two parties. They are not traded on an Exchange. Amounts are settled at expiry, typically through netting agreements, to limit credit exposure and support liquidity. Realized and unrealized gains and losses on OTC contracts (other than forward contracts) are included in cost of sales for UK GAAP and within revenues for US GAAP.

(c) OTC forward contracts

Highly developed markets exist in North America and the UK where gas and power can be bought and sold for delivery in future periods. These contracts are negotiated between two parties to purchase and sell gas and power at a specified price with delivery and settlement at a future date. These contracts are not traded on an Exchange. Although these contracts specify delivery terms for the underlying commodity, in practice a significant volume of these transactions are not settled physically. This can be achieved by transacting offsetting sale or purchase contracts for the same location and delivery period that are offset during the scheduling of delivery or despatch. The contracts contain standard terms such as delivery point, pricing mechanism, settlement terms and specification of the commodity. Typically volume is the main variable term. For UK GAAP, OTC forward sales contracts are included in turnover when settled and OTC forward purchase contracts are included in cost of sales when settled. Unrealized gains and losses are included in cost of sales. For US GAAP, where OTC forward contracts are held for trading, realized and unrealized gains are included in revenues.

(d)

Spot and term contract

Spot contracts are contracts to purchase or sell a commodity at the market price prevailing on the delivery date. Term contracts are contracts to purchase or sell a commodity at regular intervals over an agreed term. Though spot and term contracts may have a standard form, there is no offsetting mechanism in place. Spot transactions price around the bill of lading date when we take title to the inventory. These transactions result in physical delivery with operational and price risk. Spot and term contracts relate typically to purchases of third party gas and sales of the Group's gas production to third parties. For UK and US GAAP, spot and term sales are included in turnover and revenues respectively, when title passes. Similarly, spot and term purchases are included in cost of sales for UK and US GAAP.

Refer to Item 5 Operating and Financial Review Gas, Power and Renewables on page 95 and Item 11 Quantitative and Qualitative Disclosures About Market Risk on page 168 for further information.

North America

BP is one of the leading wholesale marketers and traders of natural gas in North America, the world's largest natural gas market, a business which has been built on the foundation of our position as the continent's leading producer of gas based on volumes. Our North American total natural gas sales volumes have grown from 16.1 bcf/d in 2002 to 20.6 bcf/d in 2003 and to 23.9 bcf/d in 2004. Of these sales volumes, 4.0 bcf/d was supplied from BP upstream producing operations in 2002, 3.6 bcf/d in 2003 and 3.1 bcf/d in 2004. The gas activity in the US and Canada has grown as the Group increased its scale through both organic growth of operations and through the acquisition of smaller marketing and trading companies, increasing reach into additional markets. At the same time this has occurred, the overall volumes in these markets have also increased. The Group also trades power in addition to selling and risk managing production from the Texas City co-generation facility in the US. Power trading activity grew by 10% per annum over the period 2002 to 2004.

The scale of our gas and power businesses in North America grew over the period 2002 to 2004 because of a number of factors: (i) the market exit of two key competitors; (ii) our investment in transportation and storage facilities; (iii) expansion of our staff in our supply and trading activity; and (iv) acquisitions of smaller trading and marketing companies. The OTC market for NGLs developed during this period, but the scale of activity was not significant in the context of the Group's overall operations or overall supply and trading activity.

Our North American natural gas marketing and trading strategy seeks to provide unconstrained market access for BP's equity gas. Our marketing strategy targets higher value customer segments through fully utilizing our rights to store and transport gas. These assets include those owned by BP and those contractually accessed through agreements with third parties such as pipelines and terminals.

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 one of the largest producers of natural gas in the UK based on volumes. Our total natural gas sales volumes in the UK were 4.7 bcf/d in 2004, 6.8 bcf/d in 2003 and 5.6 bcf/d in 2002. Of these volumes, 1.2 bcf/d (2003 1.4 bcf/d and 2002 1.6 bcf/d) were supplied by BP's Exploration and Production operations. The majority of natural gas sales are to power generation companies and to other gas wholesalers via long-term supply deals. Some of the natural gas continues to be sold under long-term natural gas supply contracts that were entered into prior to market deregulation. Commodity derivative contracts are used actively in combination with assets and rights to store and transport gas. This may include storing physical gas to sell in future periods or moving gas between markets to access higher prices. Commodity contracts such as over-the-counter forward contracts can be used to achieve this whilst other commodity contracts such as futures and options can be used to manage the market risk relating to changes in prices. The decline in the volumes of the activity, excluding sales of BP's own production, between 2003 and 2004 is primarily due to the overall UK market declining during the period. At the same time, however, the levels of power volumes traded increased most notably between 2002 and 2003 due to business growth.

In the first quarter of 2005 we sold our 10% interest in the Interconnector, a 1.9-bcf/d, 240-kilometre, 40-inch diameter subsea natural gas pipeline between Bacton in the UK and Zeebrugge in Belgium.

Rest of Europe

We are building a natural gas and power marketing and trading business in 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 Europe, our main marketing activities are currently in Spain. The Spanish natural gas market has continued to grow and is now deregulated ahead of the deadlines set by European law. Since April 2000, we have built a market position which currently places us as the leading foreign entrant into the Spanish gas market. In July 2002, we purchased 5% of the shares in Enagas, the owner and operator of the majority of the high pressure Spanish gas transport grid and three of Spain's four regasification terminals.

Natural Gas Liquids

	Years ended December 31,		
Group NGL sales volumes	**2004**	**2003**	**2002**
	(thousand barrels per day)		
UK	8	3	4
Rest of Europe	6		
USA (a)	393	329	296
Rest of World	203	205	232
Total	610	537	532

(a) Includes the following volumes under OTC forward contracts	188	32	3

BP is one of the leading producers and marketers of NGLs, based on sales volumes, in North America. NGLs, which are produced from gas chiefly sourced out of Alberta, Canada and the US onshore and Gulf Coast, are used as a heating fuel and as a feedstock for refineries and chemicals plants. NGLs are sold to petrochemical plants and refineries, including our own, at prevailing market prices. In addition, a significant amount of NGLs are marketed on a wholesale basis under annual supply contracts that provide for price redetermination based on prevailing market prices.

We operate natural gas processing facilities across North America with a total capacity of 8.7 bcf/d. These facilities, which we own or have an interest in, are located in major production areas across North America including Alberta, Canada, the US Rockies, the San Juan basin and coast of the Gulf of Mexico. We also own or have an interest in fractionation plants (which process the natural gas liquids stream into its separate component products) in Canada and the USA, and own or lease storage capacity in Alberta, Eastern Canada, the US Gulf Coast and mid-continent regions.

In the UK we operate one plant and we are a partner (33.33%) in a gas processing plant in Egypt which completed construction at the end of 2004.

Additionally, the Group established a trading activity in 2002 to augment certain of our activities in the US. This activity is responsible for delivering value across the overall NGL supply chain, sourcing optimal feedstock to our processing assets and securing marketing activities with flexible and competitive supply but primarily to create incremental trading gains through using storage capacity, inventory and commodity derivative contracts by arbitraging seasonal price differences. To achieve this objective, a range of commodity derivative contracts including over-the-counter options, swaps and physical forward contracts are used.

Over-the-counter contracts include a variety of options and most importantly swaps. These swaps price in relation to a wider set of products than can be achieved through the exchanges where counterparties contract for differences between, for example, fixed and floating prices. The contracts we use are similar to those for gas and power which are described in greater detail within the Marketing and Trading section above. Additionally, physical NGLs can be traded forward by using specific over-the-counter contracts. Over-the-counter forward sales contracts are used by BP to both buy and sell the physical commodity as well as a hedging tool and to arbitrage between the different markets. The scale and application of these contracts as described has increased from 2002 to 2004 as this new activity has become established.

New Market Development and LNG

Our new market development and LNG activities are focused on developing worldwide opportunities to capture international natural gas sales for our upstream natural gas resources.

BP Exploration and Production has interests in major existing LNG projects in Trinidad and Tobago, ADGAS in Abu Dhabi, the North West Shelf in Australia and we also supply gas (from Virginia Indonesia Co.) to the Bontang LNG project in Indonesia. Additional LNG supplies are being pursued through expansions of existing LNG plants in Trinidad and Tobago, the North West Shelf in Australia and greenfield developments such as Tangguh in Indonesia.

During 2004, we have taken a number of important steps to access major growth markets for the Group's equity gas. In Asia Pacific, agreements for the supply of LNG from the Tangguh development (BP 37.16%) were signed with POSCO and K Power for supply to South Korea and with Sempra for supply to Mexico and US markets. Together with an earlier agreement to supply LNG to China, markets for more than 7 million tonnes a year (9.7 bcma) of Tangguh LNG have been secured. In March 2005, Tangguh received key Government approvals for the two train launch and is now executing the major construction contracts, with start-up planned in late 2008.

During the year, BP ordered four new LNG carriers from Hyundai Heavy Industries of South Korea and agreed options for an additional four ships.

In the Atlantic and Mediterranean regions, significant progress was also made in creating opportunities to supply LNG to North American and European gas markets. In Egypt, we signed an agreement with Egyptian Natural Gas Holding Company (EGAS) to purchase 1.45 billion cubic metres per year of LNG (see Exploration and Production in this Item on page 38). Agreements were finalized with NGT Transco which will make BP and Sonatrach of Algeria the first companies for several decades to import LNG into the UK market from 2005.

Plans for the development of new LNG import terminals on the US East and Gulf coasts continued. These new access points to market, together with existing capacity rights at Cove Point in Maryland, US, Bilbao in Spain and Isle of Grain, UK, should provide important opportunities to maximize the value of the Group's gas supplies from Trinidad, Egypt and elsewhere.

In Southeast China, the construction of the Guangdong LNG Terminal and Trunkline Project (BP 30%) continued on track. First gas is scheduled for mid-2006 under the gas purchase agreement signed with Australia LNG in October 2002 that will involve deliveries from the North West Shelf project (BP 16.7%).

Solar and Renewables

Global market trends indicate a general move towards greener energy sources, including solar and wind. BP intends to participate in this developing market.

During 2003, BP repositioned BP Solar in order to improve business performance. A number of specific restructuring measures were taken in order to improve short-term results with the need to provide opportunities for long-term growth. These decisions involved the consolidation of manufacturing operations in Spain, US, India and Australia, significant staff and other overhead reductions across the global business and restructuring provisions related to improving the overall efficiency of the business.

This restructuring has enabled the Group to focus on core markets supported by global technology and manufacturing functions. 2004 has seen strong industry demand for photovoltaic products with sales increasing 38% to 99 MW of solar panel generating capacity (2003 71 MW, 2002 67 MW).

BP Solar's main production facilities are located in Frederick, Maryland USA; Madrid Spain; Sydney, Australia; and Bangalore, India. In October 2004, BP announced plans to strengthen its position in the solar electric market to support its strategic growth plan of increasing global production capacity to 200 MW by the end of 2006.

In Germany last year we opened a 4 MW solar farm, one of the largest in the world, on the site of a former plant near Merseburg, supplying enough power for 1,000 four-person households.

As a major solar operator, BP has become involved in several projects around the world. In Malaysia in 2004, we completed a $39 million project, funded by the Ministry of Rural Development, which supplied more than 13,000 systems to remote communities situated in dense tropical rainforest, high mountain ridges and flood-prone river deltas. The systems deliver power to homes, rural clinics, community halls, schools and churches.

In the Philippines, we continue to work in 2004 on the Solar Power Technology Support (SPOTS) project which is being jointly undertaken by the Philippines and Spanish governments. It has brought electricity to around 40 communities for everything from lighting in schools to water pumping for clean drinking water and vaccine refrigeration.

We are building expertise in wind energy and implementing wind projects on selected BP sites. In January 2005, we began construction of a 9 MW wind farm at our oil terminal in Amsterdam, the Netherlands. We continue to operate our 22.5 MW wind farm at the Nerefco oil refinery (both the refinery and wind farm are jointly owned with Chevron (BP 69%)) in the Netherlands, which provides electricity to the local grid.

Other Activities

We participate in power projects that support the marketing and sale of our natural gas and in cogeneration projects (i.e., power plants that produce more than one type of energy, typically power and steam) on certain BP refining and chemical manufacturing sites.

During the year, a 776 MW gas-fired power generation facility and an associated LNG regasification facility at Bilbao, Spain (BP 25% share in each) were completed and commenced commercial operation. The construction of K Power's (BP 35%) 1,074 MW gas fired combined cycle power project at Gwangyang (Korea) has continued with start up on track for 2006. The 570 MW cogeneration plant (50:50 joint venture with Cinergy Solutions, Inc.) at Texas City, Texas commenced operations in early 2004. Texas City is BP's largest refining and petrochemicals complex. BP supplies natural gas to the Texas City plant and will use the excess generation capacity to support power marketing and trading activities. The construction of a 50 MW cogeneration plant near Southampton, UK (BP 100%) is now complete and commercial start-up took place in the first half of 2005.

We also own and operate a 400 MW gas-fired power plant at Great Yarmouth in the UK (BP 100%).

In alternative fuels, we are exploring market opportunities for hydrogen fuel cells through participation in various industry projects and organisations promoting fuel cells for transport and stationary power.

OTHER BUSINESSES AND CORPORATE

Other businesses and corporate comprises Finance, the Group's coal asset (divested October 2003) the Group's aluminium asset, its investments in PetroChina and Sinopec (both divested in early 2004), interest income and costs relating to corporate activities worldwide.

	Years ended December 31,		
	2004	2003	2002
	($ million)		
Turnover	546	515	510
Total operating loss	(973)	(283)	(730)
Total assets	7,930	8,753	6,667
Capital expenditure and acquisitions	215	346	410

Finance coordinates 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.

Coal activity consisted of our 50% interest in PT Kaltim Prima Coal, an Indonesian company which operates an opencast coal mine at Sangatta in Kalimantan, Indonesia. On October 10, 2003 we completed the sale of this interest to PT Bumi Resources.

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 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, obtaining around 2% in each company. During 2004 we sold these investments for aggregate proceeds of $2,360 million.

Research, technology and engineering activities are carried out by each of the major business segments 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.

Across the Group, expenditure on research for 2004 was $439 million, compared with $349 million in 2003 and $373 million in 2002.

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 from time to time.

REGULATION OF THE GROUP'S BUSINESS

BP's exploration and production activities are conducted in many different countries and are therefore subject to a broad range of legislation and regulations. These cover virtually all aspects of exploration and production activities, including matters such as licence acquisition, production rates, royalties, pricing, environmental protection, export, taxes and foreign exchange. The terms and conditions of the leases, licences and contracts under which these oil and gas interests are held vary from country to country. These leases, licences and contracts are generally granted by or entered into with a government entity or state company and are sometimes entered into with private property owners. These arrangements usually take the form of licences or production sharing agreements.

Licences (or concessions) give the holder the right to explore for and exploit a commercial discovery. Under a licence, the holder bears the risk of exploration, development and production activities and provides the financing for these operations. In principle, the licence holder is entitled to all production minus any royalties that are payable in kind. A licence holder is generally required to pay production taxes or royalties, which may be in cash or in kind.

Production sharing agreements entered into with a government entity or state company generally obligate BP to provide all the financing and bear the risk of exploration and production activities in exchange for a share of the production remaining after royalties, if any.

In certain countries, separate licences are required for exploration and production activities and, in certain cases, production licences are limited to a portion of the area covered by the exploration licence. Both exploration and production licences are generally for a specified period of time (except for licences in the United States which remain in effect until production ceases). The term of BP's licences and the extent to which these licences may be renewed vary by area.

In general, BP is required to pay income tax on income generated from production activities (whether under a licence or production sharing agreement). In addition, depending on the area, BP's production activities may be subject to a range of other taxes, levies and assessments, including special petroleum taxes and revenue taxes. The taxes imposed upon oil and gas production profits and activities may be substantially higher than those imposed on other activities, particularly in the UK, Norway, Angola and Trinidad.

BP's other activities are also subject to a broad range of legislation and regulations in various countries in which it operates.

Health, safety and environmental regulations are discussed in more detail in Environmental Protection in this Item on page 73.

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 and natural gas 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 be material to the Group's overall results of operations or financial position. Refer to Item 18 Financial Statements Note 32 on page F-56 for the amounts provided in respect of environmental remediation and decommissioning.

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. Thirteen 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 be material to the Group's results of operations or financial position.

On March 23, 2005, an explosion and fire occurred in the Isomerization Unit of the BP Texas City refinery as the unit was coming out of planned maintenance. Fifteen contractors involved in maintenance work died in the incident. Other contractors and employees were injured, some very seriously. The US Occupational Safety and Health Administration, the US Chemical Safety and Hazard Investigation Board and the Texas Commission on Environmental Quality, among others, are conducting investigations. BP has finalized or is in process of negotiating settlements in respect of fatalities and personal injury claims arising from the incident. BP currently expects that the total amount of these settlements will not be material to the Group's results of operations or financial position for the year 2005. However, such amount may be material to the Group's results of operations for a particular quarter.

Management cannot predict future developments, such as increasingly strict requirements of environmental laws and the resulting 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 Environmental Expenditure on page 97.

BP operates in over 100 countries worldwide. In all regions of the world, BP has processes to ensure compliance with applicable regulations. In addition, each individual in the Group is required to comply with the BP health, safety and environment policy and associated expectations and standards. Our partners, suppliers and contractors are also encouraged to adopt them. The Group is working with the equity-accounted entity TNK-BP to develop management information to allow for the assessment and measurement of their activities in relation to health, safety and environment regulations and obligations. This document focuses primarily on the US and the European Union (EU), where approximately 80% of our property, plant and equipment is located, and on two issues of a global nature: climate change programmes and maritime oil spills regulations.

Climate Change Programmes

Kyoto Protocol

In December 1997, at the Third Conference of the Parties to the United Nations Framework Convention on Climate Change (UNFCCC) in Kyoto, Japan, the participants agreed on a system of differentiated internationally legally binding targets for the first commitment period of 2008 to 2012. Upon ratification by Russia in 2004, the conditions for the treaty to enter into force (minimum 55 nations representing 55% of global anthropogenic emissions) were satisfied, and it entered into force on February 16, 2005. The impact of the Kyoto agreements on global energy (and oil and gas) demand is expected to be small (see International Energy Agency World Energy Outlook 2004).

Since 1997, BP has been actively involved in policy debate. We also ran a global programme that reduced our operational greenhouse gas (GHG) emissions by 10% between 1998 and 2001. Since then, we have been taking further steps to manage GHG emissions. In assessing our performance, we look at two principal kinds of emissions: emissions generated from our operations such as refineries, chemicals plants and production facilities operational emissions; and emissions generated by our customers when they use the fuels that we sell product emissions.

Market mechanisms to allow optimum utilization of resources to meet the national Kyoto targets are being considered, developed or implemented by individual countries and also internationally through the European Union. The relative success of these systems will determine the extent to which alternative fiscal or regulatory measures may be applied. Some EU member States have indicated that they require energy product taxes to enable them to meet their Kyoto commitments within the EU burden sharing agreement.

European Union Emissions Trading Scheme

In July 2003, final agreement was reached on a Directive establishing a scheme for greenhouse gas emission allowance trading within the EU, and in January 2005, the scheme entered into force, capping the greenhouse gas emissions of major industrial emitters. Member states have finalized their National Allocation Plans, setting out how emission allowances will be allocated. BP was well prepared for the EU emission trading system (ETS), building on our experiences from our own internal emissions trading system (operated between 1999-2001) and the UK ETS. We are approaching the EU ETS on a regional, integrated basis to optimize compliance and value for the BP sites (representing roughly 25% of our global GHG emissions) that are affected.

Maritime Oil Spill Regulations

Within the United States, the Oil Pollution Act of 1990 significantly increased oil spill prevention requirements. Details of this legislation are provided in the United States Regional Review in this Item on page 75. Outside the United States, the BP operated fleet of tankers is subject to international spill response and preparedness regulations that are typically promulgated through the International Maritime Organization (IMO) and implemented by the relevant flag state authorities. The International Convention for the Prevention of Pollution From Ships (Marpol 73/78) requires vessels to have detailed shipboard emergency and spill prevention plans. The International Convention on Oil Pollution, Preparedness, Response and Co-Operation (OPRC) requires vessels to have adequate spill response plans and resources for response anywhere the vessel travels to. These conventions and separate Marine Environmental Protection Circulars also stipulate the relevant state authorities around the globe that require engagement in the event of a spill. All of these requirements together are addressed by the vessel owners in Shipboard Oil Pollution Emergency Plans. BP Shipping's liabilities for oil pollution damage under the United States Oil Pollution Act 1990 and outside the United States under the 1969/1992 International Convention on Civil Liability for Oil Pollution Damage are covered by marine liability insurance having a maximum limit of $1 billion for each accident or occurrence. This insurance cover is provided by two mutual insurance associations, The United Kingdom Steam Ship Assurance Association (Bermuda) Limited and The Britannia Steam Ship Insurance Association Limited.

At the end of 2004, the international fleet we managed numbered 34 oil tankers, all double hulled with an average age of less than two years and eight LNG ships with an average age of seven years. The international fleet renewal programme will continue into the future and should see 13 new double hulled oil tankers, four new very large liquefied petroleum gas carriers and four new liquefied natural gas carriers delivered between 2005 and 2008. In addition to its own fleet, BP will continue to charter quality ships; currently these vessels include both single- and double-hulled designs but all are vetted prior to each use to ensure they are operated and maintained to meet BP's standards.

United States Regional Review

The following is a summary of significant US environmental issues and legislation affecting the Group.

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 and new operating permits for chemical plants, refineries, marine and distribution terminals; and risk management plans for storage of hazardous substances. This law affects BP facilities producing, refining, manufacturing and distributing oil and products as well as the fuels themselves. Federal and state controls on ozone, carbon monoxide, benzene, sulphur, MTBE, nitrogen dioxide, oxygenates and Reid Vapor Pressure impact BP's activities and products in the US. BP is continually adapting its business to these rules and has the know-how to produce quality and competitive products in compliance with their requirements. Beginning January 2006, all gasoline produced by BP will have to meet the Environmental Protection Agency's (EPA's) stringent low sulphur standards. Furthermore, by June 2006, at least 80% of the highway diesel fuel produced by BP will have to meet a sulphur cap of 15 parts per million (ppm) and by June 2007, all non-road diesel fuel production will have to meet a sulphur cap of 500 ppm and then 15 ppm by June 2012.

In 2001, BP entered into a consent decree with the EPA and several states that settled alleged violations of various Clean Air Act requirements related largely to emissions of sulphur dioxide and nitrogen oxides at BP's refineries. Implementation of the decrees requirement's continues.

In March 2003 and January 2005, the South Coast Air Quality Management District filed civil lawsuits against BP's Carson, California refinery, seeking penalties of approximately $600 million for various alleged air quality violations. In March 2005, BP, without admitting liability, agreed to settle all outstanding claims for $25 million in cash penalties and approximately $6 million in past emissions fees. BP further agreed to provide $30 million over ten years in community benefit programmes and $20 million in new refinery projects aimed at reducing emissions. In addition, in 2004 (and early 2005), BP paid approximately $4 million in fines and penalties in the US, about half of which was paid in settlement of matters in Alaska and California.

Throughout 2004, BP continued to comply with 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 Group facilities engaged in oil exploration, drilling and/or production in the US and its territories. BP fully implemented EMSs in Alaska and Lower 48 exploration and production performance units during 2003 and met the requirement to spend at least $15 million on the programme. The plea agreement and the associated period of organizational probation ended on January 31, 2005.

The Clean Water Act is designed to protect and enhance the quality of US surface waters by regulating the discharge of wastewater and other discharges from both onshore and offshore operations. Facilities are required to obtain permits for most surface water discharges, install control equipment and implement operational controls and preventative measures, including spill prevention and control plans. Requirements under the Clean Water Act have become more stringent in recent years, including coverage of storm and surface water discharges at many more facilities and increased control of toxic discharges.

More specifically, recently adopted and proposed water protection initiatives have the potential to affect BP operations over the next several years. These include total maximum daily load allocations to bring surface waters into compliance with water quality standards, water quality criteria for methylmercury, selenium and nutrients, whole effluent toxicity controls, requirements for cooling water intake structures, the revision or adoption of effluent limitations guidelines and spill prevention control and countermeasure planning requirements.

The Oil Pollution Act of 1990 (OPA 90) significantly increased oil spill prevention requirements, spill response planning obligations and spill liability for tankers and barges transporting oil and for offshore facilities such as platforms and onshore terminals. To ensure adequate funding for response to oil spills and compensation for damages, when not fully covered by a responsible party, OPA 90 created a $1-billion fund which is funded by a tax on imported and domestic oil. OPA 90 also provides that all new tank vessels operating in US waters must have double hulls and existing tank vessels without double hulls must be phased out by 2015. In 2002, BP contracted with National Steel and Ship Building Company (NASSCO) for the construction of four double-hull tankers in San Diego, California. The first of these new vessels began service in 2004, demise chartered to and operated by Alaska Tanker Company (ATC). NASSCO is expected to deliver two more in 2005. The current ATC fleet consists of seven tankers: three with double bottoms and four with double hulls. By the end of 2006, all ATC vessels are expected to be double hulled.

BP has a national spill response team, the BP Americas Response Team (BART), consisting of approximately 250 trained emergency responders at Group locations throughout North America. Supporting the BART are six Regional Response Incident Management Teams and five HAZMAT Strike Teams. Collectively, these teams are 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. 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 are 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.

BP has been identified as a Potentially Responsible Party (PRP) under CERCLA and similar state statutes at approximately 800 sites. A PRP has joint and several liability for site remediation costs under some of these statutes 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 64 of these sites. For the remaining sites, the number of PRPs can range up to 200 or more. BP expects its share of remediation costs at these sites to be small in comparison to the major sites. BP has estimated its potential exposure at all sites where it has been identified as a PRP and has established provisions accordingly. BP does not anticipate that its ultimate exposure at these sites individually, or in aggregate, will be significant except as reported for Atlantic Richfield Company in the matters below.

The United States and the State of Montana seek to hold Atlantic Richfield Company liable for environmental remediation, related costs, and natural resource damages arising out of mining-related activities by Atlantic Richfield's predecessors in the upper Clark Fork River Basin ("the basin"). US EPA has estimated that the future cost of performing selected and proposed remedies in certain areas in the basin is approximately $350 million. In addition, EPA filed an action, entitled US vs. Atlantic Richfield Company, to recover past and future response costs that EPA incurred at the basin sites. In 2004, Atlantic Richfield agreed to pay $50 million plus interest to resolve EPA's claims for past costs at most sites in the basin, and the parties' consent decree settlement was approved by the court in January 2005. On a parallel track, a pending lawsuit by the state, entitled Montana vs. Atlantic Richfield Company, seeks to recover damages for alleged natural resources injuries in the basin. The United States also has claims for injury to natural resources on federal property. In 1999, Atlantic Richfield settled most of the State's claims for damages, as well as all natural resource damage claims asserted by a local Native American Tribe. The parties have not resolved the United States' claims, and they have not settled the State's claims for approximately $182.5 million in restoration damages at three sites in the basin. Atlantic Richfield Company has challenged certain government cost estimates and asserted defences and counterclaims to certain remaining claims. Past settlements among the parties may provide a framework for possible future settlement of the remaining claims in the basin.

The Group is also subject to other claims for natural resource damages (NRD) under CERCLA, OPA, and various other federal and state laws. NRD claims have been asserted by government trustees against several refineries and other Group operations. This is a developing area of the law which could impact the cost of responding to environmental conditions at some sites in the future.

In the US, many environmental cleanups are the result of strict groundwater protection standards at both the state and federal level. Contamination or the threat of contamination of current or potential drinking water resources can result in stringent cleanup requirements, but some states have addressed contamination of nonpotable water resources using similarly strict standards. BP has encouraged risk-based approaches to these issues and seeks to tailor remedies at its facilities to match the level of risk presented by the contamination.

Other significant legislation includes the Toxic Substances Control Act which regulates the development, testing, import, export and introduction of new chemical products into commerce; the Occupational Safety and Health Act which imposes workplace safety and health, training and process standards to reduce the risks of chemical exposure and injury to employees; 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. In addition, the US Department of Transportation through agencies such as the Office of Pipeline Safety and the Office of Hazardous Materials Safety regulates in a comprehensive manner the transportation of the Company's products such as gasoline and chemicals to protect the health and safety of the public.

BP is subject to the Marine Transportation Security Act and the Department of Transportation Hazardous Materials security compliance regulations in the United States. These regulations require many of our US businesses to conduct Security Vulnerability Assessments and prepare security mitigation plans which require the implementation of upgrades to security measures, the appointment and the submission of plans for approval and inspection.

See also Item 8 Financial Information Consolidated Statements and Other Financial Information Legal Proceedings on page 156.

European Union Regional Review

Within the European Union, member states either apply the Directives of the European Commission or enact regulations. By joint agreement, European Union Directives may also be applied within countries outside Europe.

A European Commission Directive for a system of Integrated Pollution Prevention and Control (IPPC) was approved in 1996. This system requires permitting through the application of Best Available Techniques (BAT) taking into account the costs and benefits. In the event that the use of BAT is likely to result in the breach of an environmental quality standard, plant emissions must be reduced further. The European Commission has stated that it hopes that all processes to which it applies will be licensed by July 2005. All plants must have a permit in accordance with the requirements of the IPPC Directive by November 2007. The Directive encompasses most activities and processes undertaken by the oil and petrochemical industry within the European Union and requires capital and revenue expenditure across these BP sites. The European Commission is expected to make recommendations for amendments to the IPPC Directive in 2005.

The European Union Large Combustion Plant Directive sets emission limit values for sulphur dioxide, nitrogen oxides and particulates from large combustion plants. It also required phased reductions in emissions from existing large combustion plants at the latest by April 1, 2001. A revised Large Combustion Plant Directive has been agreed and implementation was required by November 27, 2002. Plants will have to comply by 2008. The second important set of air emission regulations affecting BP European operations is the Air Quality Framework Directive and its three daughter Directives on ambient air quality assessment and management, which prescribe, among other things, ambient limit values for sulphur dioxide, oxides of nitrogen, particulate matter, lead, carbon monoxide, ozone, cadmium, arsenic, nickel, mercury and polyaromatic hydrocarbons. Measured or modelled exceedences of air quality limit values will require local action to reduce emissions and may impact any BP operations whose emissions contribute to such exceedences.

The Commission's Clean Air for Europe Programme is due to lead to the publication of a Thematic Strategy on Air Pollution (TSAP) during the first half of 2005. It will outline the environmental objectives for air quality and measures to be taken to achieve these objectives. Measures are likely to include revisions to the National Emissions Ceilings Directive, regulation of the concentration of fine particles (PM2.5 particulate matter less than 2.5 microns diameter) in ambient air; and new emission limits for light and heavy duty diesel vehicles, revised fuel quality and plant emission standards, and new EU measures e.g. to control evaporative losses from vehicle refuelling at service stations.

The EU has set stringent objectives to control exhaust emissions from vehicles, which are being implemented in stages. Maximum sulphur levels for gasoline and diesel fuels to apply from 2005 have also been agreed at 50 ppm and 35% maximum aromatic content for gasoline from the same date. Agreement was reached in December 2002 on a further Directive to make petrol and diesel with a maximum sulphur content of 10 ppm mandatory throughout the EU from January 2009, and from 2005 member states will also have to supply low-sulphur fuel at enough locations to allow the circulation of new low-emission engines requiring the cleaner fuel. Further measures on sulphur levels of shipping fuels and/or reduction of emissions using such fuels are expected in 2005. Possible restrictions and measures include sulphur levels in fuels of 0.1% for inland vessels by January 2010 and 1.5% for passenger ships by May 19, 2006. The impact on BP should be from installation of flue gas desulphurisation on ships and higher cost fuel. The overall impact would not be material to the Group's results of operations or financial position.

In Europe there is no overall soil protection regulation, although proposals on measures will be presented by the Commission in 2005. Certain individual member states have soil protection policies, but each has its own contaminated land regulations. There are common principles behind these regulations, including a risk based approach and recognition of costs versus benefits.

The European Commission adopted an official proposal on October 29, 2003 for a future regulation on European Chemical Policy referred to as REACH: Registration, Evaluation and Authorization of Chemicals. This proposal is now being discussed by the European Parliament and Council. Dependent on the discussions, entry in force of the regulation could happen by mid-2007. Although oil and natural gas have been temporarily exempted from the scope under the current proposal, about 30,000 other chemicals will have to be re-registered and evaluated. For the Group, this will primarily affect our refinery products, lubricants and chemicals that are manufactured and imported in the EU. Local costs will be associated with further testing, data availability systems, management and administration.

The European Commission adopted a Directive on Environmental Liability on April 21, 2004. The proposal seeks to implement a strict liability approach for damage to biodiversity and services lost from high-risk operations by April 30, 2007. Member states are considering how to implement the regime. Possibilities of damage insurance, increased preventive provisions and injunctive relief to third parties are also possible.

Other environment-related existing regulations which may have an impact on BP's operations include: the Major Hazards Directive which requires emergency planning, public disclosure of emergency plans and ensuring that hazards are assessed, and effective emergency management systems are in place; the Water Framework Directive which includes protection of groundwater; and the Framework Directive on Waste to ensure that waste is recovered or disposed without endangering human health and without using processes or methods which could harm the environment.

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 heading under this Item 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.

ORGANIZATIONAL STRUCTURE

The significant subsidiary undertakings of the Group at December 31, 2004 and the Group percentage of ordinary share 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 (*), the percentage owned being that of the Group unless otherwise indicated. Refer to Item 18 Financial Statements Note 42 on page F-82 and Note 45 on page F-86 for information on significant joint ventures and associated undertakings of the Group.

Subsidiary undertakings	%	Country of incorporation	Principal activities
International			
BP Chemicals Investments	100	England	Petrochemicals
BP Exploration Operating Co.	100	England	Exploration and production
BP Global Investments*	100	England	Investment holding
BP International*	100	England	Integrated oil operations
BP Oil International	100	England	Integrated oil operations
BP Shipping*	100	England	Shipping
Burmah Castrol*	100	Scotland	Lubricants
Algeria			
BP Amoco Exploration (In Amenas)	100	Scotland	Exploration and production
BP Exploration (El Djazair)	100	Bahamas	Exploration and production
Angola			
BP Exploration (Angola)	100	England	Exploration and production
Australia			
BP Australia	100	Australia	Integrated oil operations
BP Australia Capital Markets	100	Australia	Finance
BP Developments Australia	100	Australia	Exploration and production
BP Finance Australia	100	Australia	Finance
Azerbaijan			
Amoco Caspian Sea Petroleum	100	British Virgin Islands	Exploration and production
BP Exploration (Caspian Sea)	100	England	Exploration and production
Canada			
BP Canada Energy	100	Canada	Exploration and production
BP Canada Finance	100	Canada	Finance
Egypt			
BP Egypt Co.	100	US	Exploration and production
BP Egypt Gas Co.	100	US	Exploration and production
France			
BP France	100	France	Refining and marketing and petrochemicals
Germany			
Deutsche BP	100	Germany	Refining and marketing and petrochemicals
Veba Oil	100	Germany	Refining and marketing and petrochemicals

Subsidiary undertakings	%	Country of incorporation	Principal activities
Netherlands			
BP Capital	100	Netherlands	Finance
BP Nederland	100	Netherlands	Refining and marketing
New Zealand			
BP Oil New Zealand	100	New Zealand	Marketing
Norway			
BP Norge	100	Norway	Exploration and production
Spain			
BP España	100	Spain	Refining and marketing
South Africa			
BP Southern Africa*	75	South Africa	Refining and marketing
Trinidad			
BP Trinidad (LNG)	100	Netherlands	Exploration and production
BP Trinidad and Tobago	70	US	Exploration and production
UK			
BP Capital Markets	100	England	Finance
BP Chemicals	100	England	Petrochemicals
BP Oil UK	100	England	Refining and marketing
Britoil	100	Scotland	Exploration and production
Jupiter Insurance	100	Guernsey	Insurance
US			
Atlantic Richfield Co.	100	US	
BP America*	100	US	
BP America Production Company	100	US	Exploration and production,
BP Amoco Chemical Company	100	US	gas, power and renewables,
BP Company North America	100	US	refining and marketing,
BP Corporation North America	100	US	pipelines and petrochemicals
BP Products North America	100	US	
BP West Coast Products	100	US	
The Standard Oil Company	100	US	
BP Capital Markets America	100	US	Finance

ITEM 5 OPERATING AND FINANCIAL REVIEW

GROUP OPERATING RESULTS

	Years ended December 31,		
	2004	**2003**	**2002**
	($ million except per share amounts)		
Turnover	285,059	232,571	178,721
Profit for the year	15,731	10,482	6,795
Exceptional items, net of tax	(1,076)	(708)	(1,043)
Profit before exceptional items	14,655	9,774	5,752
Profit for the year per ordinary share (cents)	72.08	47.27	30.33
Dividends per ordinary share (cents)	29.45	26.00	24.00

On November 2, 2004, Solvay exercised its option to sell its interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America to BP. These ventures have been consolidated within the Group's results from this date.

On February 1, 2002, BP acquired a 51% interest in and operational control of Veba. Veba has been fully consolidated within the Group's results from this date. The remaining 49% of Veba was acquired on June 30, 2002.

Trading conditions in 2004 were affected by tight supplies in oil markets and by strong world economic growth.

Average crude oil prices in nominal terms in 2004 were the highest for 20 years, driven by exceptionally strong global oil demand growth and the physical disruption to US oil operations caused by Hurricane Ivan. The Brent price averaged $38.27 per barrel, an increase of more than $9 per barrel over the $28.83 per barrel average seen in 2003, and varied between $29.13 and $52.03 per barrel.

Natural gas prices in the US were also strong during 2004. The Henry Hub First of the Month Index averaged $6.13 per mmbtu, up by more than $0.70 per mmbtu compared with the 2003 average of $5.37 per mmbtu. Prices fell slightly relative to oil prices as the levels of gas in storage rose sharply. UK gas prices were also up strongly in 2004, averaging 24.39 pence per therm at the National Balancing Point compared with a 2003 average of 20.28 pence per therm.

Refining margins averaged record highs in 2004, despite weakening towards the end of the year. This reflected strong oil demand growth and record refinery throughput levels. Retail margins weakened in 2004, as rising product prices and price volatility made their impact in a competitive marketplace.

In Petrochemicals, generally improved market conditions led to a gradual increase in both volumes and margins through the year. Such gains were, however, partially offset by high and volatile energy and feedstock prices, together with adverse foreign exchange impacts.

Trading conditions in 2003 were affected by tight supplies in oil and gas markets and by the early signs of a world economic recovery, following two years of below-trend growth.

Average crude oil prices in 2003 were driven by supply disruptions in Venezuela, Nigeria and Iraq, OPEC market management and a recovery in oil demand growth following three exceptionally weak years. The Brent price averaged $28.83 per barrel, an increase of almost $4 per barrel over the $25.03 per barrel average seen in 2002 and moved in a range between $22.88 and $34.73 per barrel.

Natural gas prices in the USA were also exceptionally strong during 2003. The Henry Hub First of the Month index averaged $5.37 per mmbtu, up by more than $2 per mmbtu compared with the 2002 average of $3.22 per mmbtu. A combination of cold first quarter weather and weak domestic production kept working gas inventories relatively low for much of the year. UK gas prices were also up strongly in 2003, averaging 20.28 pence per therm at the National Balancing Point versus a 2002 average of 15.78 pence per therm.

Refining margins weakened somewhat towards the end of the year but were above historical average levels for 2003 as a whole, reflecting low commercial product inventories in key US and European markets. Retail margins for the year were relatively strong, especially in the US and Europe. Petrochemicals margins remained depressed in 2003, coming under pressure from high feedstock prices.

The trading environment was challenging during 2002, with natural gas prices and refining margins significantly weaker than in the previous year, owing to the global economic slowdown. Demand improved in most parts of the business after the first half of the year but economic conditions remained sluggish. The adverse business conditions had the greatest impact on Refining and Marketing. Worldwide refining margins were depressed for much of the year, at nearly half the average level of 2001. Margins in Petrochemicals were at levels similar to the bottom of previous cycles.

Oil prices were volatile in 2002. The Brent price ranged from around $18 per barrel to above $31 per barrel. The crude oil price increased during the second half of the year, partly reflecting a 'war premium'. Brent prices averaged $25.03 per barrel compared with $24.44 per barrel in 2001. Natural gas prices in the USA were on average lower than in 2001, at around $3.36 per mmbtu compared with $3.96 per mmbtu, owing to a large surplus of natural gas in storage during the 2001-2002 heating season. Cold weather and the start of a decline in domestic production in the USA brought about a rise in price to around $5 per mmbtu towards the end of 2002.

Hydrocarbon production for subsidiaries decreased by 7.2% in 2004, reflecting a decrease of 8.4% for liquids and a decrease of 5.8% for natural gas. The decrease includes 95 mboe/d impact of divestments. Hydrocarbon production for equity-accounted entities increased by 101.8% reflecting an increase of 108% for liquids and an increase of 69% for natural gas. This includes an increase of 108 mboe/d from the TNK-BP share of Slavneft from January 2004.

Hydrocarbon production for subsidiaries decreased by 6% in 2003, reflecting a decrease of 8.6% for liquids and a decrease of 2.8% for natural gas. The decrease reflects the 135 mboe/d impact of divestments. Hydrocarbon production for equity-accounted entities increased by 87%, reflecting an increase of 101% for liquids and an increase of 36% for natural gas. The increase reflects the inclusion of 205 mboe/d volumes incremental to Sidanco from August 29, 2003.

The increase in turnover (before the elimination of sales between businesses) for 2004 includes approximately $14 billion from higher sales prices related to gas, power, NGLs and crude oil over-the-counter forward contracts, approximately $47 billion from higher prices related to marketing and other sales (spot and term contracts, petrochemicals products, oil and gas realizations and other sales), approximately $7 billion from higher volumes of gas, power, NGLs and crude oil over-the-counter forward contracts and $8 billion from foreign exchange movements due to sales in local currencies being translated into the US dollar. This was partly offset by a net decrease of approximately $16 billion from lower volumes of marketing and other sales and a decrease of around $3 billion related to lower production volumes.

The increase in turnover (before the elimination of sales between businesses) for 2003 principally includes approximately $16 billion from higher sales prices related to gas, power, NGLs and crude oil over-the-counter forward contracts, approximately $28 billion from higher prices related to marketing and other sales (spot and term contracts, petrochemicals products, oil and gas realizations and other sales), approximately $8 billion from higher volumes of gas, power, NGLs and crude oil over-the-counter forward contracts, approximately $2 billion from higher volumes of marketing and other sales and approximately $8 billion from foreign exchange movements due to sales in local currencies being translated into the US dollar.

Under UK GAAP, over-the-counter crude oil, gas, power and NGL forward contracts are reported gross in the income statement, whereas under US GAAP, they are reported net in the income statement. Adjusting for transactions which under US GAAP should be reported net reduces revenues by $82 billion, $59 billion and $33 billion for the years 2004, 2003 and 2002, respectively. On this basis, US GAAP revenues were $203 billion, $174 billion and $146 billion for 2004, 2003 and 2002, respectively. There is a compensating reduction in cost of sales such that the overall result is unchanged. Under UK and US GAAP, changes in the fair value of exchange traded commodity derivatives and OTC options, swaps and forwards are reported net in the income statement. See Item 18 Financial Statements Note 50 on page F-103.

Profit for 2004 was $15,731 million including inventory holding gains of $1,643 million and net exceptional gains after tax of $1,076 million in respect of the sale of fixed assets and businesses or termination of operations. Inventory holding gains or losses represent the difference between the cost of sales calculated using the average cost of supplies incurred during the year and the cost of sales calculated using the first-in first-out method. The result for 2004 includes:

- in Exploration and Production, impairment charges of $621 million and a charge of $35 million in respect of Alaskan tankers no longer required;
- in Refining and Marketing, a charge of $206 million in relation to new, and revisions to existing, environmental and other provisions;
- in Petrochemicals, a charge of $1,110 million in respect of asset impairments, a charge of $39 million in respect of restructuring, and a charge of $58 million in respect of revisions to environmental and other provisions;
- in Other businesses and corporate, a charge of $225 million relating to new, and revisions to existing, environmental and other provisions, a charge of $102 million in respect of the separation of the Olefins and Derivatives business and a credit of $66 million primarily resulting from the reversal of vacant space provisions in the UK and the US.

Refer to Environmental Expenditure in this Item on page 97 for more information on environmental charges.

Profit for 2003 was $10,482 million including inventory holding gains of $16 million and net exceptional gains after tax of $708 million in respect of net profits on the sale of fixed assets and businesses or termination of operations. The result for 2003 includes:

- in Exploration and Production, impairment charges and asset writedowns of $691 million and restructuring charges of $117 million;
- in Refining and Marketing, a $369 million charge in relation to new, and revisions to existing, environmental and other provisions, Veba integration costs of $287 million and a credit of $10 million arising from the reversal of restructuring provisions;
- in Petrochemicals, a $36 million charge comprising a provision to cover future rental payments on surplus property, a charge of $20 million resulting from revisions to environmental and other provisions, and a credit of $5 million resulting from a reduction in the provision for costs associated with the closure of polypropylene capacity in the USA;
- in Other businesses and corporate, a charge of $193 million in respect of new, and revisions to existing, environmental and other provisions, a credit of $648 million relating to a US medical plan and a charge of $74 million in respect of provisions for future rental payments on surplus property;

- a credit of $280 million related to tax restructuring benefits.

Profit for 2002 was $6,795 million including inventory holding gains of $1,104 million and net exceptional gains after tax of $1,043 million in respect of net profits on the sale of fixed assets and businesses or termination of operations. The result for 2002 includes:

- in Exploration and Production, impairment charges of $1,091 million, restructuring charges of $184 million, $94 million for the write-off of our Gas-to-Liquids demonstration plant in Alaska and $55 million of litigation costs;

- in Refining and Marketing, a credit related to business interruption insurance proceeds of $184 million, as well as charges of $348 million related to Veba integration, $132 million restructuring costs, $62 million costs associated with an Olympic pipeline incident in 1999, a $35 million write-down of retail assets in Venezuela and $22 million settlement costs associated with a pre-acquisition Atlantic Richfield Company US MTBE supply contract;

- in Petrochemicals, a $140 million write-down of our Indonesian manufacturing assets, costs of $81 million related to major site restructuring and Solvay and Erdölchemie integration and $29 million for restructuring our research and technology facilities;

- in Gas, Power and Renewables, impairment costs of $30 million;

- in Other businesses and corporate, a $140 million charge for future rental payments on surplus property and a $46 million charge related to environmental and other provisions;

- $355 million adjustment to the North Sea deferred tax balance for the supplementary UK corporation tax rate and $150 million tax restructuring benefits.

In addition to the factors above, the increase in the 2004 result compared with 2003 primarily reflects higher liquids and gas realizations, higher refining margins with some offset from lower marketing margins, higher petrochemicals margins, higher contributions from the natural gas liquids and solar businesses and the impact of higher oil and gas production volumes. These increases were partly offset by higher costs and portfolio impacts.

In addition to the factors above, the increase in the 2003 result compared with 2002 primarily reflects higher oil and gas prices, higher refining and marketing margins and higher production. Further information on the impact of these factors and others on our results is included in the Business Operating Results section following.

Profits and margins for the Group and for individual business segments can vary significantly from period to period as a result of changes in such factors as oil prices, natural gas prices, refining margins and petrochemicals feedstock prices. Accordingly, the results for the current and prior periods do not necessarily reflect trends, nor do they provide indicators of results for future periods.

Employee numbers decreased from 115,250 at December 31, 2002 to 103,700 at December 31, 2003 to 102,900 at December 31, 2004. The decrease in 2003 resulted from the disposal of Fosroc Mining

(20%), the reduction of service station staff in the US (20%), the transfer of employees in Russia into TNK-BP (17%) and reorganization of Refining and Marketing operations in Germany (16%).

Capital expenditure and acquisitions	Years ended December 31, 2004	2003	2002
		($ million)	
Exploration and Production	9,839	9,576	9,226
Refining and Marketing	2,887	3,006	2,682
Petrochemicals	929	775	810
Gas, Power and Renewables	538	441	375
Other businesses and corporate	215	188	210
Capital expenditure	14,408	13,986	13,303
Acquisitions	2,841	6,026	5,790
Capital expenditure and acquisitions	17,249	20,012	19,093
Disposals	(5,048)	(6,432)	(6,782)
Net Investment	12,201	13,580	12,311

Capital expenditure and acquisitions in 2004, 2003 and 2002 amounted to $17,249 million, $20,012 million and $19,093 million, respectively. Acquisitions during 2004 included $1,354 million for including TNK's interest in Slavneft within TNK-BP and $1,355 million for the acquisition of Solvay's interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America. Acquisitions in 2003 included $5,794 million for the acquisition of our interest in TNK-BP. Acquisitions during 2002 included $5,038 million for Veba, an additional 15% interest in Sidanco and several minor acquisitions. Excluding acquisitions, capital expenditure for 2004 was $14,408 million compared with $13,986 million in 2003 and $13,303 million in 2002.

Exceptional Items

For 2004, net exceptional gains, consisting of the profit or loss on sale of fixed assets and businesses or termination of operations, were $815 million before tax ($1,076 million after tax). The major elements of the profit on sale of fixed assets of $1,829 million relate to the divestment of the Group's interests in PetroChina and Sinopec, the divestment of interests in oil and natural gas properties in Australia, Canada and the Gulf of Mexico, the reversal of the provision for the loss on sale of $217 million for the Desarrollo Zuli Occidental (DZO) and Boqueron fields in Venezuela (see Exploration and Production in this Item on page 90), the sale of the Cushing and other pipeline interests in the US, and the divestment of BP's interests in two natural gas liquids plants in Canada. The churn of retail assets and other minor divestments also contributed to the gain. The loss on sale of businesses or termination of operations for 2004 of $695 million primarily relates to the sale of the speciality intermediate chemicals business, the sale of the Fabrics and Fibres business, the closure of two petrochemicals manufacturing plants at Hull, UK, the closure of the linear alpha-olefins production facility at Pasadena, Texas, the closure of the lubricants operation of the Coryton refinery in the UK and the closure of refining operations at the ATAS refinery in Mersin, Turkey. The loss of sale of fixed assets of $319 million included the sale of interests in oil and natural gas properties in Indonesia and Gulf of Mexico, the divestment of our interest in the Singapore Refining Company Private Limited and retail churn.

Net exceptional gains were $831 million before tax ($708 million after tax) in 2003. The major elements of the profit on sale of fixed assets of $1,894 million relate to the divestment of a further 20% interest in BP Trinidad and Tobago LLC to Repsol and the sale of the Group's 96.14% interest in the Forties oil field in the UK North Sea. The sale of a package of UK Southern North Sea gas fields, the divestment of our interest in the In Amenas gas condensate project in Algeria to Statoil and the disposal of BP's interest in PT Kaltim Prima Coal also contributed to the profit on disposal. The loss on sale of fixed assets of $1,035 million includes losses on exploration and production properties in China, Norway and the US, the loss on the sale of refining and marketing assets in Germany and Central Europe and the provision for losses on sale in early 2004 of exploration and production properties in Canada and Venezuela. The loss on sale of businesses or termination of operations for 2003 of $28 million relates to the sale of our European oil speciality products business.

For 2002, net exceptional gains were $1,168 million before tax ($1,043 million after tax). The major part of the profit on the sale of fixed assets during 2002 arises from the divestment of the Group's shareholding in Ruhrgas. The other significant elements of the profit for the year are the gain on the redemption of certain preferred limited partnership interests BP retained following the Altura Energy common interest disposal in 2000 in exchange for BP loan notes held by the partnership, the profit on the sale of the Group's interest in the Colonial pipeline in the US and the profit on the sale of a US downstream electronic payment system. The profit on the sale of businesses relates mainly to the disposal of the Group's retail network in Cyprus and the UK contract energy management business. The major element of the loss on sale of fixed assets for the year relates to provisions for losses on sale of exploration and production properties in the US announced in early 2003. For 2002 the loss on sale of businesses or termination of operations relates to the disposal of our plastic fabrications business, the sale of the former Burmah Castrol speciality chemicals business Fosroc Construction, our withdrawal from solar thin film manufacturing and the provision for the loss on divestment of the former Burmah Castrol speciality chemicals businesses Sericol and Fosroc Mining.

Interest Expense and Other Finance Expense

Interest expense comprises Group interest less amounts capitalized together with interest related to equity-accounted entities. Interest expense in 2004 was $642 million compared with $644 million in 2003 and $1,067 million in 2002. These amounts included charges arising from early bond redemption of $31 million in 2003 and $15 million in 2002. The charge for 2004 reflects lower interest rates and lower debt buyback costs compared with 2003 offset by the inclusion of a full year's equity accounted interest for the TNK-BP joint venture. The charge in 2003 reflects lower interest rates and lower debt compared with 2002.

Other finance expense includes net pension finance costs, the interest accretion on provisions and interest accretion on the deferred consideration for the acquisition of investment in TNK-BP. Other finance expense in 2004 was $357 million compared with $547 million in 2003 and $73 million in 2002. The decrease in 2004 compared with 2003 primarily reflects a reduction in net pension finance costs partly offset by a revaluation of environmental and other provisions at a lower discount rate and the inclusion of a full year's charge for interest accretion on the deferred consideration for the investment in TNK-BP. The increase in 2003 compared with 2002 reflects an increase in net pension finance costs.

Taxation

The charge for corporate taxes in 2004 was $8,282 million, compared with $6,111 million in 2003 and $4,317 million in 2002. The effective rate was 34% in 2004, 36% in 2003 and 39% in 2002. The lower rate in 2004 compared with 2003 reflects the significantly higher inventory holding gain in 2004 as well as the low tax charge on the exceptional gains reported in 2004. The lower rate in 2003 compared with 2002 reflects tax restructuring benefits in 2003, as well as the rateably lower impact of goodwill amortization and depreciation on uplifted asset values (for which no tax deduction is available) on higher income in 2003. The tax rate in 2002 additionally reflected the inclusion of a $355 million charge to increase the North Sea deferred tax provision for the supplementary UK tax, and these combined effects more than offset the impact of higher inventory holding gains in 2002 compared with 2003.

Business Operating Results

Total operating profit, which is before interest expense, other finance expense, taxation, minority interests and exceptional items, was $24,427 million in 2004, $17,123 million in 2003 and $11,161 million in 2002.

Exploration and Production

		Years ended December 31,		
		2004	**2003**	**2002**
Turnover	($ million)	34,914	30,753	25,083
Profit before interest and tax	($ million)	18,530	14,669	8,280
Exceptional (gains) losses	($ million)	(152)	(913)	726
Total operating profit	($ million)	18,378	13,756	9,006
Results included:				
Exploration expense	($ million)	637	542	644
Key statistics:				
Average BP crude oil realizations (a)	($ per barrel)	36.45	28.23	24.06
Average BP NGL realizations (a)	($ per barrel)	26.75	19.26	12.85
Average BP liquids realizations (a) (b)	($ per barrel)	35.39	27.25	22.69
Average West Texas Intermediate oil price	($ per barrel)	41.49	31.06	26.14
Average Brent oil price	($ per barrel)	38.27	28.83	25.03
Average BP US natural gas realizations (a)	($ per thousand cubic feet)	5.11	4.47	2.63
Average Henry Hub gas price (c)	($/mmbtu)	6.13	5.37	3.22
Total liquids production for subsidiaries (b) (d)	(mb/d)	1,480	1,615	1,766
Total liquids production for equity-accounted entities (b) (d)	(mb/d)	1,051	506	252
Natural gas production for subsidiaries (d)	(mmcf/d)	7,624	8,092	8,324
Natural gas production for equity-accounted entities (d)	(mmcf/d)	879	521	383
Total production for subsidiaries (d) (e)	(mboe/d)	2,795	3,011	3,201
Total production for equity-accounted entities (d) (e)	(mboe/d)	1,202	595	318

(a) The Exploration and Production business does not undertake any hedging activity. Consequently, realizations reflect the market price achieved.

(b) Crude oil and NGL.

(c) Henry Hub First of Month Index.

(d) Net of royalties.

(e) 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 2004 was $35 billion compared with $31 billion in 2003 and $25 billion in 2002. The increase in 2004 reflected higher liquids and gas realizations of around $7 billion with an offset of around $3 billion due to lower production volumes (for subsidiaries) as a result of divestment activity in 2003. The increase in 2003 reflected the impact of higher liquids and natural gas realizations of approximately $7 billion with an offset of around $1 billion as a result of a decrease in production volumes in the USA and UK following divestments.

Total production for 2004 was 2,795 mboe/d for subsidiaries and 1,202 mboe/d for equity-accounted entities, compared with 3,011 mboe/d and 595 mboe/d, respectively, in the prior period. For subsidiaries, the 7.2% decrease includes 95 mboe/d impact of divestments and for equity-accounted entities the increase of 101.8% includes an increase of 108 mboe/d from the TNK-BP share of Slavneft from January 2004.

Profit before interest and tax for 2004 includes net exceptional gains of $152 million which includes the reversal of a previously reported exceptional loss on disposal in respect of our interests in Desarrollo Zuli Occidental (DZO) and Boqueron in Venezuela (as a result of the lapse of the sales agreement we retained our interests in the fields), losses on the divestment of our interest in the Kangean Production Sharing Contract and our participating interest in the Muriah Production Sharing Contract, a gain on the sale of our interest in Swordfish in the deepwater Gulf of Mexico, a gain on the sale of 5.3% of our reserves in the North West Shelf in Australia and net losses resulting from the sale of various other upstream assets. Profit before interest and tax for 2003 includes net exceptional gains of $913 million, which includes a gain on the sale of the UK North Sea Forties oil field together with a package of shallow-water assets in the Gulf of Mexico, a gain resulting from Repsol's exercise of its option to acquire a further 20% interest in BP Trinidad and Tobago LLC and net losses resulting from the sale of various other upstream assets. Profit before interest and tax for 2002 includes net exceptional losses of $726 million, which includes a gain resulting from the redemption of certain preferred partnership interests BP retained following the disposal in 2000 of the Altura Energy common interest in exchange for BP loan notes held by the partnership and net losses on the disposal of various other upstream interests.

Total operating profit for 2004 was $18,378 million including inventory holding gains of $10 million and is after an impairment charge of $267 million in respect of fields in the deepwater Gulf of Mexico and US Onshore, an impairment charge of $60 million in respect of the partner operated Temsah platform in Egypt following a blow-out, a charge of $35 million in respect of Alaskan tankers that are no longer required, an impairment charge of $108 million in respect of a gas processing plant in the USA and a field in the Gulf of Mexico Shelf and an impairment charge of $186 million related to our interests in DZO and Boqueron in Venezuela. We previously reported an exceptional loss on disposal of $217 million in respect of these assets; however, the sales agreement has lapsed and we will retain our interests in the fields. As a result of the lapse of the agreement, the exceptional loss was reversed and an impairment charge was recognized in the first quarter of 2004.

Total operating profit for 2003 was $13,756 million including inventory holding gains of $3 million. The result for 2003 includes an impairment charge of $296 million related to four assets in the Gulf of Mexico Shelf following technical reassessments and reevaluation of future investments options; an impairment charge of $133 million related to the Miller field in the UK following a decision not to proceed with waterflood and gas import options; an impairment charge of $108 million related to the Kepodang field in Indonesia; an impairment charge of $105 million related to the Yacheng field in China; and a $49 million write-down of the Viscount asset in the North Sea. Although all of these fields continue in operation, BP has disposed of its interest in the Kepodang field in 2004. Additionally, there were restructuring charges of $117 million in respect of ongoing restructuring activities in the UK and North America.

Total operating profit for 2002 was $9,006 million including inventory holding gains of $3 million. The result for 2002 includes a charge of $1,091 million related to the impairments of Shearwater in the North Sea, Rhourde El Baguel in Algeria, LL652 and Boqueron in Venezuela, Pagerungan in Indonesia and Badami in Alaska, following full technical reassessments and reevaluations of future investment opportunities. All these fields continued in operation. In addition, there were restructuring charges of $184 million relating to significant restructuring to reposition the business in North America and the North Sea, $94 million for the write-off of our Gas-to-Liquids demonstration plant in Alaska and $55 million of litigation costs. The restructuring costs comprised $145 million of severance, $19 million repatriation and other costs of $20 million, which were mostly settled in 2002.

The primary reasons for the increase in operating profit for 2004 compared with 2003 are higher liquids and gas realizations of around $5,150 million combined with an increase of $400 million due to higher volumes, partly offset by adverse foreign exchange impacts and inflationary pressures of around $350 million and higher costs of around $650 million. Operating profit for 2004 includes a charge of $191 million, reflecting an increase in the provision for unrealized profit in inventory compared with a charge of $61 million in 2003.

The primary reasons for the increase in operating profit in 2003 compared with 2002 are higher natural gas realizations partly offset by higher costs and other factors. Higher natural gas realizations contributed $5,400 million to operating profit. This was offset by an increase of approximately $790 million in the charge for depreciation and an increase in other costs of around $340 million. Lower production volumes in the USA and the UK reduced profit by approximately $100 million and the net impact of acquisitions and divestments was a further reduction of about $100 million. Exploration expense was $102 million lower in 2003 compared with 2002. Operating profit for 2003 includes a charge of $61 million reflecting an increase in the provision for unrealized profit in inventory compared with a charge of $154 million in 2002.

Total hydrocarbon production for 2003 was 3,010 mboe/d for subsidiaries and 596 mboe/d for equity-accounted entities compared with 3,201 mboe/d and 252 mboe/d, respectively, in 2002. For subsidiaries this includes the 135 mboe/d impact of divestments and for equity-accounted entities reflects the inclusion of 205 mboe/d volumes incremental to Sidanco, from August 29, 2003.

Refining and Marketing

		Years ended December 31,		
		2004	**2003**	**2002**
Turnover (a)	($ million)	179,587	149,477	125,836
Profit before interest and tax	($ million)	5,967	2,270	2,582
Exceptional (gains) losses	($ million)	117	213	(613)
Total operating profit	($ million)	6,084	2,483	1,969
Global Indicator Refining Margin (b)	($/bbl)	6.08	3.88	2.11
Refining availability (c)	(%)	95.4	95.5	96.1
Refinery throughputs	(mb/d)	2,976	3,097	3,103
Total marketing sales	(mb/d)	4,002	3,969	4,180

(a) Excludes BP's share of joint venture turnover of $594 million in 2004, $453 million in 2003 and $415 million in 2002.

(b) The Global Indicator Refining Margin is the average of six regional industry indicator margins which we weight 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. The refining margins are industry specific rather than BP specific measures, which we believe are useful to investors in analysing trends in the industry and their impact on our results. The margins are calculated by BP based on published crude oil and product prices and take account of fuel utilization and catalyst costs. No account is taken of BP's other cash and non-cash costs of refining, such as wages and salaries and plant depreciation. The indicator margin may not be representative of the margins achieved by BP in any period because of BP's particular refining configurations and crude and product slate.

(c) Refining availability is the weighted average percentage of the period that refinery units are available for processing, after accounting for downtime such as turnarounds.

The changes in turnover are explained in more detail below:-

		Years ended December 31,		
		2004	2003	2002
Sale of crude oil through spot and term contracts	($ million)	25,027	23,915	18,150
Sale of crude oil, through over-the-counter forward contracts	($ million)	18,485	14,098	11,599
Marketing, spot and term sales of refined products	($ million)	124,458	102,003	87,520
Other sales including non-oil and to other segments	($ million)	11,617	9,461	8,567
		179,587	149,477	125,836
Sale of crude oil through spot and term contracts	(mb/d)	2,505	2,553	2,659
Sale of crude oil through over-the-counter forward contracts	(mb/d)	1,303	1,284	1,276
Marketing, spot and term sales of refined products	(mb/d)	6,398	6,688	6,563

Turnover for 2004 was $180 billion compared with $149 billion in 2003 and $126 billion in 2002. The increase in turnover in 2004 compared with 2003 was principally due to an increase of around $23 billion in marketing, spot and term sales of refined products. This was due to higher prices of $28 billion and a positive foreign exchange impact due to a weaker dollar of $8 billion, offset by lower volumes of $13 billion. Additionally, sales of crude oil, spot and term contracts increased by $1 billion due to higher prices of $2 billion partly offset by lower volumes of $1 billion; and sales of crude oil through over-the-counter forward contracts increased by $4 billion and other sales increased by $2 billion, primarily due to higher prices. The $24 billion increase in turnover in 2003 compared to 2002 was primarily due to due an increase in marketing, spot and term sales of refined products of around $15 billion. This was due to higher prices of $5 billion, a positive foreign exchange impact due to a weaker dollar of $8 billion and higher volumes of $2 billion. Additionally, sales of crude oil, spot and term contracts increased by $6 billion due to higher prices of $7 billion, partly offset by lower volumes of $1 billion. Sales of crude oil through over-the-counter forward contracts increased by $2 billion primarily due to higher prices and other sales increased by around $1 billion, primarily due to higher volumes.

For both UK and US GAAP spot and term contracts are reported gross in the income statement except where transactions have been determined to be agency arrangements. Under UK GAAP, over-the-counter crude oil forward contracts are reported gross in the income statement, whereas under US GAAP, they are reported net in the income statement. Adjusting for transactions which under US GAAP should be reported net reduces revenues by $22.1 billion, $15.8 billion and $11.6 billion for the years 2004, 2003 and 2002, respectively. On this basis, US GAAP sales were $157.5 billion, $133.7 billion and $114.2 billion for 2004, 2003 and 2002, respectively. There is a compensating reduction in the segment cost of sales such that the overall segment result is unchanged. Under UK and US GAAP, changes in the fair value of exchange traded commodity derivatives and OTC options, swaps and forwards are reported net in the income statement. See Item 18 Financial Statements Note 50 on page F-103.

Refer to Item 4 Information on the Company Refining and Marketing on page 44 for further information.

Profit before interest and tax for 2004 includes net exceptional losses of $117 million which includes a gain on disposal of the Cushing to Chicago Pipeline in the US, and losses on the disposal of our interest in the Singapore Refining Company Private Limited and the closure of the lubricants operation of the Coryton Refinery in the UK. Profit before interest and tax for 2003 includes net exceptional losses of $213 million resulting from a number of disposals which primarily relate to retail assets. Profit before interest and tax for 2002 includes net exceptional gains of $613 million which include gains on the sale of our interest in Colonial Pipeline and a US downstream electronic payment system, along with a number of smaller items.

Total operating profit for 2004 was $6,084 million, including inventory holding gains of $1,245 million, and is after charging $206 million in relation to new, and revision to existing, environmental and other provisions. The Group undertakes an annual review of its environmental provisions in relation to current and former refinery, retail and other sites taking account of new legislation and emerging industry practice.

Total operating profit for 2003 was $2,483 million after inventory holding losses of $48 million and is after Veba integration costs of $287 million, a $369 million charge in relation to new, and revisions to existing, environmental and other provisions, and a credit of $10 million arising from the reversal of restructuring provisions.

Total operating profit for 2002 was $1,969 million including inventory holding gains of $1,049 million and is after a credit related to business interruption insurance proceeds of $184 million, as well as charges of $348 million related to Veba integration, $132 million restructuring costs, $62 million costs associated with an Olympic pipeline incident in 1999, a $35 million write-down of retail assets in Venezuela and $22 million settlement costs associated with a pre-acquisition Atlantic Richfield Company US MTBE supply contract.

The increase in operating profit for 2004 compared with 2003 is primarily due to stronger refining margins contributing approximately $3,100 million, offset by a decrease in marketing margins of approximately $400 million, the impact of weaker US dollar of approximately $250 million and charges of around $310 million related primarily to a review of carrying value of fixed and current marketing assets. The increase was further offset by higher purchased energy costs of around $100 million and portfolio impacts of around $100 million. Refining throughputs at 2,976 kb/d were 4% lower than in 2003 due principally to the disposal of BP's interests in SRC, the closure of refining operations at the ATAS Refinery in Mersin, south eastern Turkey and the disposal of the Bayernoil refinery in Germany in the second quarter of 2003. Refining availability for the year was 95.4% compared with 95.5% in 2003 and marketing volumes were relatively flat compared with 2003.

In addition to the factors above, operating profit for 2003 compared with 2002 reflects approximately $1,400 million from improved refining margins and approximately $600 million from marketing margins improvement. This was offset by adverse foreign exchange effects of around $100 million and additional portfolio impacts of around $150 million. Refining throughputs were relatively flat compared with 2002, with refining availability for the year at 95.5% in 2003 compared with 96.1% in 2002. Marketing volumes for 2003 were 4% lower than 2002, due to divestments.

The integration of Veba, which began in February 2002, was essentially completed during 2003. The 2003 charges of $287 million relating to the Veba acquisition comprised some $46 million of severance costs, $37 million of other integration costs such as consulting, studies and internal project teams, $48 million of system infrastructure and application costs and the balance of $156 million related to additional synergy projects. 2003 cash outflows related to these charges were approximately $260 million.

The 2002 charges of $348 million related to the Veba acquisition comprised $210 million of severance costs, $77 million of other integration costs such as consulting, studies and internal project teams, $24 million of system infrastructure and application costs, $22 million of office consolidation and relocation and $15 million of additional synergy projects. 2002 cash outflows related to these charges were approximately $140 million. The $132 million restructuring costs were associated with several restructuring and cost reduction initiatives during 2002 in different business units and support functions, primarily in the USA, Western Europe and in Africa. The largest single functional area affected was information technology. In Venezuela an impairment review was triggered by the current political crisis and poor business performance in 2002.

Petrochemicals

		Years ended December 31,		
		2004	2003	2002
Turnover	($ million)	21,209	16,075	13,064
Profit before interest and tax	($ million)	(551)	623	191
Exceptional (gains) losses	($ million)	563	(38)	256
Total operating profit	($ million)	12	585	447
Chemicals Indicator Margin (a)	($/te)	140	112	104
Production volumes (b)	(kte)	28,927	27,943	26,988

(a) The Chemicals Indicator Margin (CIM) is a weighted average of externally based industry product margins. It is based on market data collected by Nexant in their quarterly market analyses, which we weight 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, LAOs, acetic acid, vinyl acetate monomers and nitriles. Not included are fabrics and fibres, PAOs, anhydrides, speciality intermediates and the remaining parts of the solvents and acetyls businesses. CIM is an environmental trend indicator. Changes in CIM are indicative of market environment trends rather than representative of the actual margins achieved by BP in any particular period.

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

Turnover has increased from $13 billion in 2002 to $16 billion in 2003 and to $21 billion in 2004. The increase in turnover for 2004 compared with 2003 was attributable principally to an increase of around $4 billion from higher prices, and an increase of around $1 billion from higher sales volumes, primarily to Asia. The increase in turnover for 2003 compared with 2002 primarily reflects higher sales prices.

Profit before interest and tax for 2004 includes net exceptional losses of $563 million associated largely with the closure of two plants at Hull, the sale of our Fabrics and Fibres business, the closure of the linear alpha-olefins production facility at Pasadena, Texas, the sale of our speciality intermediates businesses and the exit from the Baglan Bay site in the UK. Profit before interest and tax for 2003 includes net exceptional gains of $38 million resulting from a number of small transactions. Profit before interest and tax for 2002 includes net exceptional losses of $256 million, including a loss on the sale of our plastic fabrications business, a loss on the sale of Fosroc Construction, a loss associated with the closure of polypropylene capacity at Cedar Bayou, Texas and several other small transactions.

Total operating profit for 2004 was $12 million including inventory holding gains of $349 million and is after a charge of $1,110 million in respect of asset impairments, a charge of $39 million in respect of restructuring and a charge of $58 million in respect of revisions to environmental and other provisions.

Total operating profit for 2003 was $585 million including inventory holding gains of $55 million and is after a $36 million charge comprising a provision to cover future rental payments on surplus property, a charge of $20 million resulting from revisions to environmental and other provisions and a credit of $5 million resulting from a reduction in the provision for costs associated with the closure of polypropylene capacity in the USA.

Total operating profit for 2002 was $447 million including inventory holding gains of $26 million and is after a $140 million write-down of our Indonesian manufacturing assets held for sale following a review of immediate prospects and opportunities for future growth in a highly competitive market, costs of $81 million related to major site restructuring and Solvay and Erdölchemie integration and $29 million for restructuring our research and technology facilities.

In addition to the factors above, operating profit for 2004 compared with 2003 reflects higher margins of approximately $660 million and higher sales volumes of approximately $190 million, offset partially by higher fixed costs, adverse foreign exchange impacts and portfolio change of approximately $560 million.

In addition to the factors above, operating profit for 2003 reflects a decrease of around $180 million resulting from prolonged margin weakness, primarily in our European polymers business, a result from SARS-affected businesses in Asia that was approximately $60 million lower during the first half of the year and additional charges of $55 million related to additional depreciation from new plants, asset writedowns and provisions for bad debt, partly offset by an increase of $130 million due to higher sales volumes and lower fixed costs of around $60 million when compared to 2002.

BP's share of production for 2004 was 28,927 thousand tonnes, up 4% on 2003 due to higher asset utilization and increased Asian PTA capacity during the year, with additional High Density Polyethylene capacity in the fourth quarter from the acquisition of the BP Solvay ventures. Production for 2003 was 27,943 thousand tonnes, up 3.5% on 2002 due to improved asset utilization across the business as well as new production capacity and increased ownership in our Asian associated undertakings.

Gas, Power and Renewables

		Years ended December 31,		
		2004	**2003**	**2002**
Turnover	($ million)	83,320	65,639	37,580
Profit before interest and tax	($ million)	982	576	2,020
Exceptional (gains) losses	($ million)	(56)	6	(1,551)
Total operating profit	($ million)	926	582	469
Total natural gas sales volumes (a)	(mmcf/d)	31,690	30,439	24,852

(a) Includes marketing, trading and supply sales.

The changes in turnover are explained in more detail below:

		Years ended December 31,		
		2004	**2003**	**2002**
Gas marketing sales	($ million)	13,532	12,929	9,401
Sale of gas through over-the-counter forward contracts	($ million)	43,099	32,338	14,049
Sale of power through over-the-counter forward contracts	($ million)	16,110	11,950	8,138
Sale of NGLs through over-the-counter forward contracts	($ million)	2,251	416	40
Other sales (including NGL marketing)	($ million)	8,328	8,006	5,952
	($ million)	83,320	65,639	37,580
Gas marketing sales volumes	(mmcf/d)	5,244	5,881	5,840
Natural gas sales by Exploration and Production	(mmcf/d)	3,670	3,923	4,000
Sale of gas through over-the-counter forward contracts	(mmcf/d)	22,776	20,635	15,012

		Years ended December 31,		
Total natural gas sales volumes	(mmcf/d)	31,690	30,439	24,852
Sale of power through over-the-counter forward contracts	(gwh/d)	1,162	1,012	650
Sale of NGLs through over-the-counter forward contracts	(mb/d)	188	32	3

Turnover for 2004 was $83 billion compared with $66 billion in 2003. Gas marketing sales increased by $0.6 billion as price increases of $1.8 billion more than offset lower volumes of $1.2 billion. Sales of gas through over-the-counter forward contracts increased by $10.8 billion due to increased volumes of $3.0 billion and increased prices of $7.8 billion. The increase in sales of power through over-the-counter forward contracts of $4.2 billion related to higher prices of $2.4 billion and higher volumes of $1.8 billion and the increase in sales of NGLs through over-the-counter forward contracts of $1.8 billion primarily related to higher volumes. Finally, other sales (including NGL marketing) rose by $0.3 billion, of which $1.7 billion related to higher prices and $1.4 billion to lower volumes. Turnover for 2003 was $66 billion compared with $38 billion in 2002. Gas marketing sales increased by $3.5 billion primarily due to higher prices. Sales of gas through over-the-counter forward contracts increased by $18.3 billion due to higher prices of $14.5 billion and higher volumes of $3.8 billion. The increase of $3.8 billion in sales of power through over-the-counter forward contracts and the increase of $0.4 billion in sales of NGLs through over-the-counter forward contracts related primarily to higher volumes. Finally, other sales increased by around $2.0 billion primarily as a result of higher prices. Volumes of gas and power sold through over-the-counter forward contracts increased in 2003 and 2004 as operations grew both organically and through acquisition of smaller marketing and trading companies. Volumes of NGLs sold through over-the-counter forward contracts grew over the period as a result of incremental trading and wholesale activities in the US that were established in 2002 and grew significantly in 2004.

Under UK and US GAAP spot and term contracts are reported gross in the income statement except where transactions have been determined to be agency arrangements. Under UK GAAP, sales of gas, power and NGLs through over-the-counter forward contracts are reported gross in the income statement, whereas under US GAAP they are reported net in the income statement. Adjusting for transactions which under US GAAP should be reported net reduces revenues by $59.5 billion, $43.1 billion and $21.1 billion for the years 2004, 2003 and 2002, respectively. On this basis, US GAAP sales were $23.9 billion, $22.6 billion and $16.4 billion for 2004, 2003 and 2002, respectively. There is a compensating reduction in the segment cost of sales such that the overall segment result is unchanged. Under UK and US GAAP, changes in the fair value of exchange traded commodity derivatives and OTC options, swaps and forwards are reported net in the income statement. See Item 18 Financial Statements Note 50 on page F-103.

Refer to Item 4 Information on the Company Gas, Power and Renewables on page 62 for further information.

Profit before interest and tax for 2004 includes exceptional gains of $56 million from the disposal of BP's interests in NGL plants in Canada. Profit before interest and tax for 2003 includes net exceptional losses of $6 million resulting from several small transactions. Profit before interest and tax for 2002 includes net exceptional gains of $1,551 million that primarily relate to the disposal of our interest in Ruhrgas.

Total operating profit for 2004 was $926 million including inventory holding gains of $39 million.

Total operating profit for 2003 was $582 million including inventory holding gains of $6 million.

Total operating profit for 2002 was $469 million including inventory holding gains of $51 million, and is after a charge of $30 million related to the impairment of a cogeneration power plant under construction in the UK. The impairment is the result of a significant fall in power prices in the UK over the previous two years.

In addition to the factors above, the principal additional factors contributing to the increase in operating profit in 2004 compared with 2003 were a higher contribution from the natural gas liquids and solar businesses of approximately $350 million due to higher unit margins and higher volumes.

In addition to the factors above, the increase in operating profit for 2003 compared with 2002 reflects improvement in the marketing and trading business. Marketing and trading results increased by approximately $250 million with equal contributions from higher volumes and improved margins. Results for the LNG business also improved showing an increase of $90 million. This more than offset decreases of $70 million in the NGL business due to high natural gas prices relative to liquids prices in North America which led to lower sales volumes, the absence of any contribution from the Ruhrgas shareholding (sold in August 2002 and contributed $112 million in 2002) and a restructuring charge of $45 million in our Solar business.

Other Businesses and Corporate

		Years ended December 31,		
		2004	**2003**	**2002**
Turnover	($ million)	546	515	510
Profit (loss) before interest and tax	($ million)	314	(184)	(744)
Exceptional (gains) losses	($ million)	(1,287)	(99)	14
Total operating loss	($ million)	(973)	(283)	(730)

Other businesses and corporate comprises Finance, the Group's coal asset (divested October 2003), the Group's aluminium asset, its investments in PetroChina and Sinopec (both divested in early 2004), interest income and costs relating to corporate activities.

The profit before interest and tax for 2004 includes exceptional gains of $1,287 million primarily related to the sale of our investment in PetroChina and our investment in Sinopec. The loss before interest and tax for 2003 includes net exceptional gains of $99 million, which includes a gain on the sale of our interest in PT Kaltim Prima Coal, an Indonesian coal mining company, partly offset by net losses on several small transactions. The loss before interest and tax in 2002 includes net exceptional losses of $14 million resulting from several small transactions.

The net cost of Other businesses and corporate amounted to $973 million in 2004, $283 million in 2003 and $730 million in 2002. The operating loss for 2004 includes a charge of $225 million relating to new, and revisions to existing, environmental and other provisions, a charge of $102 million in respect of the separation of the Olefins and Derivatives business and a credit of $66 million primarily resulting from the reversal of vacant space provisions in the UK and the US. The operating loss for 2003 includes a charge of $193 million relating to new, and revisions to existing, environmental and other provisions, a credit of $648 million relating to a US medical plan and a charge of $74 million in respect of provisions for future rental payments on surplus leasehold properties. The operating loss for 2002 includes provisions of $140 million for future rentals on surplus leasehold property and a charge of $46 million for environmental liabilities in respect of a divested business.

Environmental Expenditure

	Years ended December 31,		
	2004	**2003**	**2002**
		($ million)	
Operating expenditure	526	498	485
Clean-ups	25	45	49
Capital expenditure	524	546	548
New provisions for environmental remediation	588	515	312
New provisions for decommissioning	294	1,159	308

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 that 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 operating and capital expenditures for 2004 were broadly in line with 2003. Similar levels of operating capital expenditures are expected in the foreseeable future. In addition to operating and capital expenditures, we also create provisions for future environmental remediation. Expenditure against such provisions is normally in subsequent periods and is not included in environmental operating expenditure reported for such periods. The charge for environmental remediation provisions in 2004 includes $484 million resulting from a reassessment of existing site obligations and $104 million in respect of provisions for new sites.

Provisions for environmental remediation are made when 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 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 and other assets where the fair value of the asset retirement obligation can be reasonably estimated. On installation of oil or natural gas production facility a provision is established which represents the discounted value of the expected future cost of decommissioning the asset. Additionally, we undertake periodic reviews of existing provisions. These reviews take account of revised cost assumptions, changes in decommissioning requirements and any technological developments.

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 32 on page F-56. See also Item 4 Information on the Company Environmental Protection on page 73.

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 will be reviewed periodically.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flow

	Years ended December 31,		
	2004	2003	2002
	($ million)		
Net cash inflow from operating activities	28,554	21,698	19,342
Dividends from joint ventures	1,908	131	198
Dividends from associated undertakings	291	417	368
Net cash outflow from servicing of finance and returns on investment	(342)	(711)	(911)
Tax paid	(6,378)	(4,804)	(3,094)
Net cash outflow for capital expenditure and financial investment	(8,712)	(6,124)	(9,628)
Net cash outflow from acquisitions and disposals	(3,242)	(3,548)	(1,337)
Equity dividends paid	(6,041)	(5,654)	(5,264)
Net cash inflow (outflow) before financing	6,038	1,405	(326)
Financing	6,777	1,129	(163)
Management of liquid resources	132	(41)	(220)
Increase (decrease) in cash	(871)	317	57
	6,038	1,405	(326)

Net cash inflow from operating activities increased to $28,554 million from $21,698 million in 2003, reflecting an increase in profit of $7,288 million, an increase in depreciation and amounts provided of $1,643 million and the absence of discretionary funding for the Group's pension plans of $2,533 million which was incurred in 2003. This was partially offset by an additional working capital requirement of $2,618 million and a higher share of profits of joint ventures and associated undertakings of $2,136 million. Net cash inflow from operating activities increased to $21,698 million in 2003 from $19,342 million in 2002, reflecting an increase in profit of $5,625 million partly offset by $2,533 million discretionary funding for the Group's pension plans, an additional working capital requirement of $1,091 million and higher share of profits of joint ventures and associated undertakings of $472 million.

Dividends from joint ventures and associated undertakings were $2,199 million in 2004 compared with $548 million in 2003 and $566 million in 2002. The increase in 2004 compared with 2003 is primarily due to the dividend from TNK-BP. The decrease in 2003 compared with 2002 was related to the Ruhrgas and Altura transactions in 2002 partly offset by the dividend from TNK-BP in 2003.

The net cash outflow from servicing of finance and returns from investments was $342 million in 2004, $711 million in 2003 and $911 million in 2002. The lower cash outflow in 2004 and 2003 is primarily due to lower interest payments. Additionally, interest received was higher in 2004.

Tax paid increased to $6,378 million in 2004 from $4,804 million in 2003 and $3,094 million in 2002, primarily reflecting the increase in profits in each period.

Net cash outflow for capital expenditure and financial investment amounted to $8,712 million in 2004 compared with $6,124 million in 2003 and $9,628 million in 2002. The increase in 2004 compared with 2003 reflects lower disposal proceeds of $1,930 million and an increase in payments for fixed assets of $667 million. The decrease in 2003 over 2002 reflects higher disposal proceeds of $3,783 million.

Net cash outflow from acquisitions and disposals produced net cash outflows of $3,242 million in 2004, $3,548 million in 2003 and $1,337 million in 2002. The lower outflow in 2004 compared with 2003 reflects higher disposal proceeds of $546 million and increased acquisition spending of $191 million.

The higher outflow in 2003 compared with 2002 reflects lower disposal proceeds of $4,133 million and lower acquisition spending of $1,762 million.

Overall net cash outflow for capital expenditure and acquisitions, net of disposals, was $11,954 million in 2004 compared with $9,672 million in 2003 and $10,965 million in 2002.

Equity dividends paid have increased to $6,041 million in 2004 compared with $5,654 million in 2003 and $5,264 million in 2002. The increase in both years reflects the impact of the higher dividend per share, partly offset by share repurchases.

Overall net cash inflow before financing was $6,038 million in 2004, $1,405 million in 2003 and was a net outflow of $326 million in 2002 as a result of the factors outlined above.

Net cash inflow from Financing was $6,777 million in 2004 compared with $1,129 million in 2003 and an outflow of $326 million in 2002. The increases in 2004 and 2003 are primarily due to the repurchase of ordinary share capital. See Item 18 Financial Statements Note 37 on page F-74.

The Group has had significant levels of investment for many years. Investment, excluding acquisitions, was $14.4 billion in 2004, $14.0 billion in 2003 and $13.3 billion in 2002. Sources of funding are completely fungible, but the majority of the Group's funding requirements for new investment come from cash generated by existing operations. There has been little change in the Group's level of net debt, that is debt less cash and liquid resources; net debt was $20.3 billion at the end of 2002, $20.2 billion at the end of 2003 and was $21.6 billion at the end of 2004.

Over the period 2000 to 2004 our cash inflows and outflows were balanced, with sources and uses both totalling $152 billion. Since 2000, the year in which we completed the purchase of Atlantic Richfield Company, the price of Brent has averaged $29.00/bbl, somewhat higher than was expected as the period opened. The following table summarizes the five year sources and uses of cash:

Sources	**$ billion**	**Uses**	**$ billion**
Operating cash flow	112	Capital expenditure	66
Dividends from joint ventures and associated undertakings	5	Acquisitions	17
Divestments	33	Servicing of finance and and returns on investments	4
Movement in net debt	2	Tax paid	25
		Share buybacks	14
		Dividends	26
	152		152

Significant acquisitions made for cash were more than offset by divestitures. Net investment over the same period has averaged $10 billion per year. Dividends, which grew on average by 8.2% per year in dollar terms, used $26 billion. $14 billion was used for share repurchases. Finally, cash was used to strengthen the financial condition of certain of our pension funds.

Trend information

Over the next three or four years we expect to see additional cash flows coming from three main sources:

First, having contributed $2.5 billion in 2003 to address deficits in our funded pension plans, we now expect to return to a funding programme of $400-600 million per year. We have the capacity to adjust this funding should circumstances warrant.

Secondly, organic capital expenditure, that is capital expenditure excluding acquisitions, is expected to level off as we pass the peak of the recent investment cycle.

Lastly, and most importantly, that we expect operations to be our main source of additional cash. This includes the benefits from capital coming into service in our new Exploration and Production profit centres and greater margin contributions from our Customer Facing Businesses.

We expect capital expenditure, excluding acquisitions, to be around $14 billion in 2005; the exact level will depend on the level of the dollar and is subject to our ability to continue to offset normal underlying inflation of around 2% per annum. Refer to Item 4 for further information.

Further out, for the medium term, a level of around $14 billion is a reasonable expectation.

Total production for 2005 is estimated at an average of between 2.85 and 2.9 mmboe/d for subsidiaries and between 1.25 and 1.3 mmboe/d for equity accounted entities; these estimates are before any divestments and are based on our $20/bbl planning basis. The exact level will depend on oil prices, divestments and many other factors.

The anticipated decline in production volumes from subsidiaries in our existing profit centres is partly mitigated by the development of new projects and the investment in incremental reserves in and around existing fields. We expect that this overall decline in production from subsidiaries in our existing profit centres will be more than compensated for by strong increases in production from subsidiaries in our new profit centres over the next few years. Production in our equity-accounted joint venture, TNK-BP, is also expected to grow over the next few years.

The most important determinants of cash flows in relation to our oil and natural gas production are the prices of these commodities. In a stable price environment, cash flows from currently developed proved reserves are expected to decline in a manner consistent with anticipated production decline rates. Development activities associated with recent discoveries, as well as continued investment in these producing fields, are expected to more than offset this decline, resulting in increased operating cash flows over the next few years. Cash flows from equity-accounted entities are expected to be in the form of dividend payments.

Dividends and Other Distributions to Shareholders and Gearing

Our dividend policy is to progressively grow the dividend. In pursuing this policy and in setting the levels of dividends we are guided by several considerations, including:

the prevailing circumstances of the Group. Last year we achieved all we set out to do. Performance is on track; investments are going in and producing revenue; strategy is on track;

the future investment patterns and sustainability of the Group. We have a strong set of opportunities which we are pursuing, giving us a clear view of our future whether related to resources or customers and we are confident about that future;

the future trading environment. It does seem that oil prices have a support level of $30/bbl for at least the medium term. This gives us some comfort in considering the timing of dividend changes. We currently use as our planning assumption $20/bbl as a measure for testing the downside in the balance between investment and total distributions to shareholders. However, in light of sustained high oil prices, the Group is in the course of reviewing this planning assumption.

Under UK GAAP our gearing band was 25-35%. Subsequent to the adoption of International Financial Reporting Standards (IFRS) from January 1, 2005, we reduced our gearing band from 25-35% to 20-30% in order to maintain the economic substance of our financial framework. This new band continues to give us an efficiently leveraged capital structure, and adequate protection against unforeseen events. This reduction brings the gearing band back to where it was, prior to the introduction of FRS19 in 2002.

We remain committed to returning 100% of the excess of net cash inflow before equity dividends paid to our investors so long as oil prices remain above $20/bbl, all other things being appropriate. Though we could use some of the excess of net cash inflow before equity dividends paid, for example, for material acquisitions if we saw opportunities which fitted the strategy, but we see no such opportunities at present.

We plan to continue our programme of share buybacks, subject to market conditions. Since the completion of the Atlantic Richfield acquisition in 2000 until the end of 2004 we have repurchased some 1,602 million shares at a cost of $13.5 billion, reducing the number of shares in issue (after accounting for the issuance of shares under employee stock programmes and to AAR in respect of TNK) by more than 5.2%. During the first quarter of 2005, we bought back 193 million shares, at a cost of $2 billion.

The discussion above and following contains forward-looking statements with regard to future cash flows, future levels of capital expenditure and divestments, future production volumes, working capital, the renewal of borrowing facilities, shareholder distributions and share buybacks, expected payments under contractual and commercial commitments. These forward-looking statements are based on assumptions which management believes to be reasonable in the light of the Group's operational and financial experience, however, no assurance can be given that the forward-looking statements will be realized. You are urged to read the cautionary statement under Item 3 Key Information Forward-Looking Statements on page 13 and Item 3 Key Information Risk Factors on pages 11 and 12 which describe the risks and uncertainties that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements. The Company provides no commitment to update the foward-looking statements or to publish financial projections for forward-looking statements in the future.

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 US dollars.

The Group's finance debt is almost entirely in US dollars and at December 31, 2004 amounted to $23,091 million (2003 $22,325 million) of which $10,184 million (2003 $9,456 million) was short term.

Net debt was $21,607 million at the end of 2004, a decrease of $1,414 million compared with 2003. The ratio of net debt to net debt plus equity was 22% at the end of 2004 and 22% at the end of 2003.

The maturity profile and fixed/floating rate characteristics of the Group's debt are described in Item 18 Financial Statements Notes 27 and 30 on pages F-43 and F-53, respectively.

We have in place a European Debt Issuance Programme (DIP) under which the Group may raise $8 billion of debt for maturities of one month or longer. At June 28, 2005, the amount drawn down against the DIP was $5,987 million.

In addition, the Group has in place a US Shelf Registration under which it may raise $6 billion of debt for maturities of one month or longer. At June 28, 2005 $5,475 million had been raised under the US Shelf Registration.

Commercial paper markets in the USA and Europe are a primary source of liquidity for the Group. At December 31, 2004 the outstanding commercial paper amounted to $4,180 million (2003 $4,243 million).

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

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, 2004 the Group's share of third party borrowings of joint ventures and associated undertakings was $2,821 million (2003 $2,151 million) and $1,048 million (2003 $922 million) respectively. These amounts are not reflected in the Group's debt on the balance sheet.

The Group has issued third party guarantees under which amounts outstanding at December 31, 2004 are summarized below. Some guarantees outstanding are in respect of borrowings of joint ventures and associated undertakings noted above.

	Guarantees expiring by period						
	Total	2005	2006	2007	2008	2009	2010 and thereafter
	($ million)						
Guarantees issued in respect of:							
Borrowings of joint ventures and associated undertakings	1,281	175	155	103	207	87	554
Liabilities of other third parties	650	138	71	352	40	10	39

At December 31, 2004 contracts had been placed for authorized future capital expenditure estimated at $6,765 million. 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, 2004, the Group had available undrawn committed borrowing facilities of $4,500 million ($3,700 million at December 31, 2003).

Contractual Commitments

The following table summarizes the Group's principal contractual obligations at December 31, 2004. Further information on borrowings and capital leases is given in Item 18 Financial Statements Note 30 on page F-53 and further information on operating leases is given in Item 18 Financial Statements Note 18 on page F-30.

	Payments due by period						
Expected payments by period under contractual obligations and commercial commitments	**Total**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010 and thereafter**
	($ million)						
Borrowings (a)	20,693	10,069	3,014	2,682	1,539	1,724	1,665
Capital lease obligations	4,752	152	254	258	268	280	3,540
Operating leases	8,354	1,483	1,106	944	858	754	3,209
Decommissioning liabilities	8,247	140	215	194	164	139	7,395
Environmental liabilities	2,620	517	499	428	322	205	649
Pensions (b)	21,707	967	959	954	946	938	16,943
Other postretirement benefits (c)	11,357	256	240	243	242	244	10,132
Purchase obligations (d)	95,204	65,635	9,852	3,736	2,623	2,317	11,041

(a) Expected payments exclude interest payments on borrowings.

(b) Represents the expected future contributions to funded pension plans and payments by the Group for unfunded pension plans.

(c) Represents the expected future payments for postretirement benefits.

(d) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2005 include purchase commitments existing at December 31, 2004 entered into principally to meet the Group's short term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Item 11 Quantitative and Qualitative Disclosures about Market Risk on page 168.

The following table summarizes the nature of the Group's unconditional purchase obligations.

Purchase obligations payments due by period	Payments due by period						
	Total	2005	2006	2007	2008	2009	2010 and thereafter
	($ million)						
Crude oil and oil products	42,139	35,408	2,930	787	621	596	1,797
Natural gas	23,373	14,919	2,725	1,207	740	585	3,197
Chemicals and other refinery feedstocks	11,588	4,677	1,618	917	620	542	3,214
Utilities	11,928	8,825	1,618	239	172	173	901
Transportation	3,006	890	574	304	231	234	773
Use of facilities and services	3,170	916	387	282	239	187	1,159
Total	95,204	65,635	9,852	3,736	2,623	2,317	11,041

The following table summarizes the Group's capital expenditure commitments at December 31, 2004 and the proportion of that expenditure for which contracts have been placed. The Group expects its total capital expenditure excluding acquisitions to be around $14 billion in 2005 and for the medium term.

Capital expenditure commitments including amounts for which contracts have been placed	Total	2005	2006	2007	2008	2009	2010 and thereafter
	($ million)						
Committed on major projects	16,860	7,185	3,693	2,301	1,309	860	1,512
Amounts for which contracts have been placed	6,765	4,381	1,510	610	159	91	14

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 & 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, including through the commercial paper markets, and also has undrawn committed borrowing facilities to meet currently foreseeable borrowing requirements. At December 31, 2004, the Group had substantial amounts of undrawn borrowing facilities available, including committed facilities of $4,500 million expiring in 2005 ($3,700 million expiring in 2004). These facilities are with a number of international banks and borrowings under them would be at pre-agreed rates. The Group expects to renew the facilities on an annual basis. Certain of these facilities support the Group's commercial paper programme.

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 derivatives to manage market risk, the Group has credit exposures through its dealings in the financial and specialized oil, natural gas and power markets. The Group controls the related credit risk through credit approvals, limits, use of netting arrangements and monitoring procedures. Counterparty credit validation, independent of the dealers, is undertaken before contractual commitment.

OUTLOOK

World economic growth was sustained across all regions into the second quarter of 2005, albeit at slightly lower rates than in 2004. The current outlook is for continued moderation of economic growth towards the long-term trend. Growth is expected to remain positive, if less synchronized, across all regions in 2005.

Oil prices reached a further record average of $47.62 per barrel (dated Brent) in the first quarter and have increased further during the second quarter to date, averaging $51.50 (April 1 to close June 28). Total Russian industry production growth has slowed to 3% over the first five months 2005 but Chinese import growth has also slowed. Prices remain supported by limited spare production capacity even though OECD commercial inventories are above seasonal five year average levels. OPEC's decision in mid June to raise quotas by 500,000 b/d is unlikely to increase actual production significantly.

US gas prices averaged $6.27/mmbtu (Henry Hub first of month index) in the first quarter and have increased during the second quarter, averaging $6.75/mmbtu (April 1 to June 28). US working gas inventories remain above year-earlier and five year average levels but the futures market continues to signal a supply-constained market.

Refining margins averaged $5.94/bbl during the first quarter and have increased sharply to $8.49/bbl during the second quarter to date (April 1 to June 28). Margin levels in April were a record for any month since 1990. Gasoline appears well-supplied ahead of the driving season but the refining environment continues to be underpinned by robust demand growth and recently by concerns over distillate supply this coming winter.

After a very weak first quarter, retail margins improved significantly during the first six weeks of the second quarter. From late May, rising crude and product prices have since dampened marketing margins, and the outlook remains volatile.

CRITICAL ACCOUNTING POLICIES AND NEW ACCOUNTING STANDARDS

UK Generally Accepted Accounting Policies

BP prepares its financial statements in accordance with UK generally accepted accounting practice (UK GAAP). The Group's significant accounting policies are summarized in Item 18 Financial Statements Note 1 on Page F-10.

The accounts for the year ended December 31, 2004 have been prepared using accounting policies consistent with those adopted in the preparation of the 2003 accounts, except for the change in accounting policy for pensions and other postretirement benefits and for shares held in employee share ownership plans for the benefit of employee share schemes.

Segment information for 2003 has been restated to reflect the transfer of NGLs activities from Exploration and Production to Gas, Power and Renewables.

Inherent in the application of many of the accounting policies used in the preparation of the financial statements is the need for BP 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 the estimates and assumptions used. The following summary provides further information about the critical accounting policies that could have a significant impact on the results of the Group and should be read in conjunction with the Notes on Accounts.

The accounting policies and areas that require the most significant judgements and estimates to be used in the preparation of the consolidated financial statements are in relation to oil and natural gas accounting, including the estimation of reserves; impairment; and provisions for deferred taxation, decommissioning, environmental liabilities, pensions and other postretirement benefits.

Accounting policy changes in 2004

From January 1, 2004, BP changed its accounting policies for pensions and other postretirement benefits. In addition, BP also changed its accounting policy for shares held in employee share ownership plans for the benefit of employee share schemes.

With effect from January 1, 2004, BP has adopted a new UK accounting standard: Financial Reporting Standard No. 17 'Retirement Benefits' (FRS 17). FRS 17 requires that the assets and liabilities arising from an employer's retirement benefit obligations and any related funding should be included in the financial statements at fair value and that the operating costs of providing retirement benefits to employees should be recognized in the income statement in the periods in which the benefits are earned by employees. This contrasts with SSAP 24, which requires the cost of providing pensions to be recognized on a systematic and rational basis over the period during which the employer benefits from the employee's services. The difference between the amount charged in the income statement and the amount paid as contributions into the pension fund is shown as a prepayment or provision on the balance sheet.

Urgent Issues Task Force Abstract No. 38 'Accounting for Employee Share Ownership Plan (ESOP) Trusts' (Abstract No. 38) changes the presentation of an entity's own shares held in an ESOP trust from requiring them to be recognized as assets to requiring them to be deducted in arriving at shareholders' funds. Transactions in an entity's own shares by an ESOP trust are similarly recorded as changes in shareholders' funds and do not give rise to gains or losses. This treatment is in line with the accounting for purchases and sales of own shares set out in Urgent Issues Task Force Abstract No. 37 'Purchases and Sales of Own Shares' (Abstract 37).

Abstract No. 37 requires a holding of an entity's own shares to be accounted for as a deduction in arriving at shareholders' funds, rather than being recorded as assets. Transactions in an entity's own shares are similarly recorded as changes in shareholders' funds and do not give rise to gains or losses. Abstract No. 37 applies where a company purchases treasury shares under new legislation that came into effect in December 2003.

Urgent Issues Task Force Abstract No. 17 'Employee share schemes' (Abstract 17) was amended by Abstract No. 38 to reflect the consequences for the profit and loss account of the changes in the presentation of an entity's own shares held by an ESOP trust. Amended Abstract No. 17 requires that the minimum expense should be the difference between the fair value of the shares at the date of award and the amount that an employee may be required to pay for the shares (i.e. the 'intrinsic value' of the award). The expense was previously determined either as the intrinsic value or, where purchases of shares had been made by an ESOP trust at fair value, by reference to the cost or book value of shares that were available for the award.

These changes in accounting policy have resulted in a prior year adjustment. BP shareholders' interest at January 1, 2002 has been reduced by $150 million, profit for the year ended December 31, 2002 decreased by $50 million and profit for the year ended December 31, 2003 increased by $215 million.

Oil and natural gas accounting

Accounting for oil and gas exploration activity is subject to special accounting rules that are unique to the oil and gas industry. In the UK, these are contained in the Statement of Recommended Practice (SORP) 'Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities'.

The Group follows the successful efforts method of accounting for its oil and natural gas exploration and production activities.

The acquisition of geological and geophysical seismic information, prior to the discovery of proved reserves, is expensed as incurred, similar to accounting for research and development costs.

Licence and property acquisition costs are initially capitalized as unproved properties within intangible assets. These costs are amortized on a straight-line basis until such time as either exploration drilling is determined to be successful or it is unsuccessful and all costs are written off. Each property is reviewed on an annual basis to confirm that drilling activity is planned and it is not impaired. If no future activity is planned the remaining balance of the licence and property acquisition costs is written off.

For exploration wells and exploratory-type stratigraphic test wells, costs directly associated with the drilling of wells are temporarily capitalized within intangible fixed assets, pending determination of whether potentially economic oil and gas reserves have been discovered by the drilling effort. These costs include employee remuneration, materials and fuel used, rig costs, delay rentals and payments made to contractors. The determination is usually made within one year after well completion, but can take longer, depending on the complexity of the geologic structure. If the well did not encounter potentially economic oil and gas quantities, the well costs are expensed as a dry hole and are reported in exploration expense. Exploration wells that discover potentially economic quantities of oil and gas and are in areas where major capital expenditure (e.g. offshore platform or a pipeline) would be required before production could begin, and where the economic viability of that major capital expenditure depends upon the successful completion of further exploration work in the area, remain capitalized on the balance sheet as long as additional exploration appraisal work is under way or firmly planned.

For complicated offshore exploration discoveries, it is not unusual to have exploration wells and exploratory-type stratigraphic test wells remaining suspended on the balance sheet for several years while additional appraisal drilling and seismic work on the potential oil and gas field is performed or while the optimum development plans and timing are established. All such carried costs are subject to regular technical, commercial and management review, on at least an annual basis, to confirm the continued intent to develop, or otherwise extract value from, the discovery. If this is no longer the case, the costs are immediately expensed.

Once a project is sanctioned for development, the carrying values of licence and property acquisition costs and exploration and appraisal costs are transferred to production assets within tangible assets.

Field development costs subject to depreciation are expenditures incurred to date together with sanctioned future development expenditure approved by the Group.

The capitalized exploration and development costs for proved oil and gas properties (which include the costs of drilling unsuccessful wells) are amortized on the basis of oil-equivalent barrels that are produced in a period as a percentage of the estimated proved reserves. The estimated proved reserves used in these unit-of-production calculations vary with the nature of the capitalized expenditure. The reserves used in the calculation of the unit-of-production amortization are as follows:

(a) Proved developed reserves for producing wells.

(b) Total proved reserves for development costs.

(c) Total proved reserves for licence and property acquisition costs.

(d) Total proved reserves for future decommissioning costs.

The impact of changes in estimated proved reserves is dealt with prospectively by amortizing the remaining book value of the asset over the expected future production. If proved reserve estimates are revised downwards, earnings could be affected by higher depreciation expense or an immediate write-down of the property's book value (see discussion of impairment of fixed assets and goodwill below).

Given the large number of producing fields in the Group's portfolio, it is unlikely that any changes in reserve estimates, year on year, will have a significant effect on prospective charges for depreciation.

US GAAP requires the unit-of-production depreciation rate to be calculated on the basis of development expenditure incurred to date and proved developed reserves. If production commences before all development wells are drilled, a portion of the development costs incurred to date should be excluded from the unit-of production depreciation rate. In respect of the Group's portfolio of fields there is no material difference between the Group's charge for depreciation determined on a UK GAAP basis and on a US GAAP basis.

Oil and natural gas reserves

As a UK-registered company reporting under UK GAAP, BP estimates its proved reserves under UK accounting rules for oil and gas companies contained in the Statement of Recommended Practice, 'Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities' (UK SORP). This differs from the basis for determining reserve required by the US Securities and Exchange Commission. In estimating its reserves under UK SORP, BP uses long-term planning prices; these are the long term price assumptions on which the Group makes decisions to invest in the development of a field. Using planning prices for estimating proved reserves removes the impact of the volatility inherent in using year-end spot prices on our reserve base and on cash flow expectations over the long term. The Group's planning prices for estimating reserves through the end of 2004 were $20/bbl for oil and

$3.50/mmbtu for natural gas. However, in light of sustained high oil prices, the Group is in the course of reviewing these planning prices. Applying higher year-end prices to reserve estimates and assuming they apply to the end-of-field life has the effect of increasing proved reserves associated with concessions (tax and royalty arrangements) for which additional development opportunities become economic at higher prices or where higher prices make it more economic to extend the life of a field. On the other hand, applying higher year-end prices to reserves in fields subject to PSAs has the effect of decreasing proved reserves from those fields because higher prices result in lower volume entitlements. We believe that our long-term planning price assumptions provide the most appropriate basis for estimating oil and gas reserves and we will continue to use this basis for our UK reporting.

In determining 'reasonable certainty' for UK SORP purposes, BP applies a number of additional internally imposed assessment principles, such as the requirement for internal approval and final investment decision (which we refer to as project sanction), or for such project sanction within six months and, for additional reserves in existing fields, the requirement that the reserves be included in the business plan and scheduled for development within three years. These principles are also applied for SEC reporting purposes.

The Company's proved reserves estimates for the year ended December 31, 2004 reported in this Form 20-F reflect year-end prices and some adjustments which have been made vis-à-vis individual asset reserve estimates based on different applications of certain SEC interpretations of SEC regulations relating to the use of technology (mainly seismic) to estimate reserves in the reservoir away from wellbores and the reporting of fuel gas (i.e. gas used for fuel in operations on the lease) within proved reserves. The 2004 year-end marker prices used were Brent $40.24/bbl and Henry Hub $6.01/mmbtu. The other 2004 movements in proved reserves, are reflected in the tables showing movements in oil and gas reserves by region in Item 18 Financial Statements Supplementary Oil and Gas Information on pages S-1 to S-8.

The Group manages its hydrocarbon resources in three major categories: prospect inventory, non-proved resources and proved reserves. When a discovery is made, volumes transfer from the prospect inventory to the non-proved resource category. The reserves move through various non-proved resources sub-categories as their technical and commercial maturity increases through appraisal activity. Reserves in a field will only be categorized as proved when all the criteria for attribution of proved status have been met, including an internally imposed requirement for project sanction, or for sanction expected within six months. Internal approval and final investment decision are what we refer to as project sanction.

At the point of sanction, all booked reserves will be categorized as proved undeveloped (PUD). Volumes will subsequently be recategorized from PUD to proved developed (PD) as a consequence of development activity. The first PD bookings will occur at the point of first oil or gas production. Major development projects typically take one to four years from the time of initial booking to the start of production. Adjustments may be made to booked reserves due to production, reservoir performance, commercial factors, acquisition and divestment activity and additional reservoir development activity.

The Group reassesses its estimate of proved reserves on an annual basis. The estimated proved reserves of oil and natural gas are subject to future revision. As discussed below, oil and natural gas reserves have a direct impact on certain amounts reported in the financial statements.

Proved reserves do not include reserves that are dependent on the renewal of exploration and production licences unless there is strong evidence to support the assumption of such renewal.

Impairment of fixed assets and goodwill

BP assesses its fixed assets, including goodwill, for possible impairment if there are events or changes in circumstances that indicate that carrying values of the assets may not be recoverable. Such indicators include changes in the Group's business plans, changes in commodity prices leading to unprofitable performance and, for oil and gas properties, significant downward revisions of estimated proved reserve quantities. The assessment for impairment 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.

Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation and technology improvements on operating expenses, production profiles and the outlook for global or regional market supply-and-demand conditions for crude oil, natural gas, commodity chemicals and refined products.

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. Previously, these were a Brent Oil price of $20 per barrel and a Henry Hub gas price of $3.50 per mmbtu. Beginning in the fourth quarter of 2004, this has been modified. Prices used for future cash flow calculations are assumed to decline from existing levels in equal steps over the next three years to the long-term planning assumptions ($20/$3.50 for Brent and Henry Hub at December 31, 2004). These long-term planning assumptions are subject to periodic review and modification. In light of sustained high oil prices, the Group is in the course of reviewing these planning assumptions. 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.

Charges for impairment are recognized in the Group's results from time to time as a result of, among other factors, adverse changes in the recoverable reserves from oil and natural gas fields, low plant utilization or reduced profitability. 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

The Group has approximately $7.7 billion of carry-forward tax losses in the UK and Germany, which would be available to offset against future taxable income. It is unlikely that the Group's effective tax rate will be significantly affected in the near term by utilization of losses not previously recognized as deferred tax assets. Carry-forward tax losses in other taxing jurisdictions have not been recognized as deferred tax assets, and are unlikely to have a significant effect on the Group's tax rate in future years.

Deferred taxation is not generally provided in respect of liabilities that may arise on the distribution of accumulated reserves of overseas subsidiaries, joint ventures and associated undertakings.

Decommissioning 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 on the installation of those facilities, reflecting our legal obligations at that time. Most of these removal events 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. Consequently, the timing and amounts of future cash flows are subject to significant uncertainty.

Decommissioning provisions associated with downstream and petrochemical facilities are generally not provided for as such potential obligations cannot be measured given their indeterminate settlement dates. The Group performs periodic reviews of its downstream and petrochemical long-lived assets for any changes in facts and circumstances that might require the recognition of a decommissioning provision.

The timing and amount of future expenditures are reviewed annually, together with the interest rate to be used in discounting the cash flows. The interest rate used to determine the balance sheet obligation at the end of 2004 was 2.0%, 0.5% lower than at the end of 2003. The interest rate represents the real rate (i.e. adjusted for inflation) on long-dated government bonds.

Environmental costs

BP also makes judgements 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.

The provision for environmental liabilities is reviewed at least annually. The interest rate used to determine the balance sheet obligation at December 31, 2004 was 2.0%, 0.5% lower than at the previous balance sheet date.

Pensions and other postretirement benefits

Accounting for pensions and other postretirement benefits involves judgement 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, healthcare cost-trend rates and rates of utilization of healthcare services by retirees. These assumptions are based on the environment in each country. Determination of the projected benefit obligations for the Group's defined benefit pension and postretirement plans is 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 also affect future results of operations.

Pension and other postretirement benefit assumptions are discussed and agreed with the independent actuaries in December each year. These assumptions are used to determine the projected benefit obligation at the year end and hence the surplus and deficits recorded on the Group's balance sheet, and pension and postretirement expense for the following year.

The pension assumptions at December 31, 2004 and 2003 under FRS17 are summarized below.

	UK		Other		USA	
	2004	2003	2004	2003	2004	2003
			(%)			
Rate of return on assets	7.0	7.0	6.0	6.0	8.0	8.0
Discount rate	5.25	5.5	5.0	5.5	5.75	6.0
Future salary increases	4.0	4.0	4.0	4.0	4.0	4.0
Future pension increases	2.5	2.5	2.5	2.5	nil	nil
Inflation	2.5	2.5	2.5	2.5	2.5	2.5

The assumed rate of investment return and discount rate have a significant effect on the amounts reported. A one-percentage-point change in these assumptions for the principal plans would have the following effects:

	One-percentage point	
	Increase	Decrease
	($ million)	
Investment return:		
Effect on pension expense in 2005	(312)	314
Discount rate:		
Effect on pension expense in 2005	(87)	88
Effect on pension obligation at December 31, 2004	(4,508)	5,575

The assumptions used in calculating the charge for US postretirement benefits are consistent with those shown above for US pension plans. The assumed future healthcare cost trend rate is shown below.

	2005	2006	2007	2008	2009 and subsequent years
			(%)		
Beneficiaries aged under 65	9	8	7	6	5
Beneficiaries aged over 65	12	10	8	7	6

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	Decrease
	($ million)	
Effect on total of postretirement benefit expense in 2005	39	(31)
Effect on postretirement obligation at December 31, 2004	458	(373)

Adoption of International Financial Reporting Standards (IFRS)

An 'International Accounting Standards Regulation' was adopted by the Council of the European Union (EU) in June 2002. This regulation requires all EU companies listed on an EU stock exchange to use 'endorsed' International Financial Reporting Standards (IFRS), published by the International Accounting Standards Board (IASB), to report their consolidated results with effect from January 1, 2005. The IASB completed its development of IFRS to be adopted in 2005 during the first half of 2004, but has also published certain amendments and interpretations of IFRS which would be available for early adoption if endorsed by the EU.

The process of endorsement of IFRS by the EU to allow adoption by companies in 2005 is well advanced but not yet complete.

BP's project team includes a broadly based representation from across the Group designed to plan for and achieve a smooth transition to IFRS. The project team has examined all implementation aspects, including changes to accounting policies, the presentation of the Group's results, systems impacts and the wider business issues that may arise from such a fundamental change. The Group has reported its results from the first quarter of 2005 using IFRS. However, the implementation may still be affected by developments in the IASB's standard-setting process and the endorsement of standards and interpretations by the EU.

The Group has decided that, for the purposes of the restatement of prior periods currently reported under UK GAAP, the date of transition to IFRS is January 1, 2003. However, in accordance with the provisions of IFRS 1, the date of adoption of International Accounting Standards Nos. 32 and 39, which deal with the recognition and presentation of financial instruments, is set at January 1, 2005, with no restatement of prior periods' results.

The process of finalizing the restatements of the results and financial position for 2003 and 2004 under IFRS, was completed in March 2005. The major effects of changing from current accounting practice to IFRS are in the following areas: goodwill acquired in a business combination; deferred tax related to business combinations and in respect of the valuation of inventories; accounting for items falling within the scope of IAS Nos. 32 and 39, including embedded derivatives and hedge accounting; the treatment of major overhaul expenditure; exchanges of fixed assets; recognition of dividend liabilities; and share-based payments. Certain joint arrangements with third parties, where BP currently accounts for its share of individual assets, liabilities, income and expense, will be accounted for using the equity method, resulting in reclassifications within the income statement and balance sheet.

The adoption of IFRS, subject to developments in the standard-setting process and the endorsement of standards and interpretations, resulted in a $1,344 million and $1,966 million increase in profit for the years ended December 31, 2004 and 2003, respectively, and a $236 million increase in BP shareholders' interest at December 31, 2004.

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 generally accepted accounting principles (US GAAP). The principal differences between US GAAP and UK GAAP for BP Group reporting are discussed in Item 18 Financial Statements Note 50 on page F-103.

Impact of New US Accounting Standards

Other postretirement benefits: In May 2004, the Financial Accounting Standards Board (FASB) issued Staff Position No. 106-2 'Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003' (the Medicare Act). The provisions of the Medicare Act provide for a federal subsidy for plans that provide prescription drug benefits and meet certain qualifications, and alternatively would allow prescription drug plan sponsors to co-ordinate with the Medicare benefit. The Group reflected the impact of the legislation by reducing its actuarially determined obligation for postretirement benefits at December 31, 2004 and will reduce the net cost for postretirement benefits in subsequent periods. The $577 million reduction in liability was reflected as an actuarial gain (assumption change).

Inventory: In November 2004, the FASB issued Statement of Financial Accounting Standards No. 151 'Inventory Costs an amendment of ARB No. 43, Chapter 4' (SFAS 151). SFAS 151 requires that items, such as idle facility expense, excessive spoilage, double freight and re-handling costs, be recognized as current-period charges. SFAS 151 also requires that the allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. SFAS 151 is effective for accounting periods beginning after June 15, 2005. The adoption of SFAS 151 is not expected to have a significant effect on profit, as adjusted to accord with US GAAP, or BP shareholders' interest, as adjusted to accord with US GAAP.

Discontinued operations: In November 2004, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 03-13 'Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations' (EITF 03-13). Under EITF 03-13, a disposed component of an enterprise is classified as a discontinued operation only where the ongoing entity has no continuing direct cash flows and does not retain an interest, contract or other arrangement sufficient to enable the entity to exert significant influence over the disposed component's operating and financial policies after disposal. EITF 03-13 is effective for a component of an enterprise that is either disposed of or classified as held for sale in accounting periods beginning after December 15, 2004.

Revenue: In November 2004, the EITF began discussion of Issue No. 04-13 'Accounting for Purchases and Sales of Inventory with the Same Counterparty' (EITF 04-13). EITF 04-13 addresses accounting issues that arise when a company both sells inventory to and buys inventory from another entity in the same line of business. The purchase and sale transactions may be pursuant to a single contractual arrangement or separate contractual arrangements and the inventory purchased or sold may be in the form of raw material, work-in-process or finished goods. At issue is whether the revenue, inventory cost and cost of sales should be recorded at fair value or whether the transactions should be classified as nonmonetary transactions. The EITF, which did not reach a consensus on the issue, requested the FASB staff to further explore the alternative views.

Practice within the oil and natural gas industry varies for buy/sell arrangements with common counterparties and physical exchanges. The Group accounts for buy/sell arrangements and physical exchanges on a net basis.

Nonmonetary asset exchanges: In December 2004, the FASB issued Statement of Financial Accounting Standards No. 153 'Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29' (SFAS 153). SFAS 153 eliminates the Accounting Principles Board Opinion No. 29 exception for nonmonetary exchanges of similar productive assets and replaces it with an exception for exchanges of nonmonetary assets that do not have commercial substance. SFAS 153 is effective for nonmonetary asset exchanges occurring in accounting periods beginning after June 15, 2005. The Group adopted SFAS 153 with effect from January 1, 2005. The adoption of SFAS 153 did not have a significant effect on profit, as adjusted to accord with US GAAP, or BP shareholders' interest, as adjusted to accord with US GAAP.

Share options: In December 2004, the FASB issued Statement of Financial Accounting Standards No. 123 (revised 2004) 'Share-Based Payment' (SFAS 123R). SFAS 123R, which is a revision of Statement of Financial Accounting Standards No. 123 'Accounting for Stock-Based Compensation' (SFAS 123), supersedes APB Opinion No. 25 'Accounting for Stock Issued to Employees'. Under SFAS 123R, share-based payments to employees and others are required to be recognized in the income statement based on their fair value. Pro forma disclosure is no longer a permitted alternative. SFAS 123R must be adopted no later than July 1, 2005.

The Group currently accounts for share-based employee compensation based on the intrinsic value method and, as such, generally recognizes no compensation cost for employee share options. Disclosure of the pro forma effect on net income and earnings per share if the Group had applied the fair value recognition provisions of SFAS 123 to share-based employee compensation in prior years is included in Item 18 Financial Statements Note 38 on page F-75.

Effective January 1, 2005, as part of the adoption of IFRS, the Group adopted International Financial Reporting Standard No. 2 'Share-based Payment' (IFRS 2). IFRS 2 requires the recognition of expense when goods or services are received from employees or others in consideration for equity instruments or amounts that are based on the value of an entity's equity instruments. The recognition and measurement provisions of IFRS 2 are similar to those of SFAS 123R.

In adopting IFRS 2, the Group elected to restate prior years to recognize the expense associated with equity-settled share-based payment transactions that were not fully vested as of January 1, 2003 and the liability associated with cash-settled share-based payment transactions as of January 1, 2003.

The Group adopted SFAS 123R with effect from January 1, 2005. Had the Group adopted SFAS 123R in prior years, the impact would have approximated the pro forma expense included in Item 18 Financial Statements Note 38 on page F-75.

Taxation: In December 2004, the FASB issued Staff Position No. 109-1 'Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004' (FSP 109-1). FSP 109-1, effective upon issuance, requires that the manufacturers' deduction provided for under the American Jobs Creation Act of 2004 (the Jobs Creation Act) be accounted for as a special deduction in accordance with FASB Statement of Financial Accounting Standards No. 109, 'Accounting for Income Taxes,' rather than a tax rate reduction. The manufacturers' deduction will be recognized by the Company in the year the benefit is earned.

In December 2004, the FASB issued Staff Position No. 109-2 'Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004' (FSP 109-2). The Jobs Creation Act provides a special one-time provision allowing earnings of certain non-US companies to be repatriated to a US parent company at a reduced tax rate. FSP 109-2, effective upon issuance, permits additional time beyond the financial reporting period of enactment in order to evaluate the effect of the Jobs Creation Act without undermining an entity's assertion that repatriation of non-US earnings to a US parent company is not expected within the foreseeable future. As provided by FSP 109-2, the Group has elected to defer a decision on potentially altering current plans regarding the permanent reinvestment in certain non-US subsidiaries and corporate joint ventures. The income tax effects associated with any repatriation of unremitted earnings as a result of the Jobs Creation Act cannot be reasonably estimated at this time.

Provisions: In March 2005, the FASB issued FASB Interpretation No. 47 'Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143' (Interpretation 47). Under Interpretation 47, a conditional asset retirement obligation represents an unconditional obligation to perform an asset retirement activity where the timing or method of settlement are conditional on a future event that may or may not be within the control of the entity. Interpretation 47 clarifies that an entity is required to recognize a liability, when incurred, for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional asset retirement obligation is factored into the measurement of the liability when sufficient information exists. SFAS 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation. Interpretation 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. Interpretation 47 is effective for fiscal years ending after December 15, 2005. The Group has not yet completed its evaluation of the impact of adopting Interpretation 47 on the Group's profit, as adjusted to accord with US GAAP, or BP shareholders' interest, as adjusted to accord with US GAAP.

Fixed assets: FASB Statement of Financial Accounting Standards No. 19 'Financial Accounting and Reporting by Oil and Gas Producing Companies' (SFAS 19) requires the cost of drilling an exploratory well (exploration or exploratory-type stratigraphic test wells) to be capitalized pending determination of whether the well has found proved reserves. If this determination cannot be made at the conclusion of drilling, SFAS 19 sets out additional requirements for continuing to carry the cost of the well as an asset. These requirements include firm plans for further drilling and a one-year time limitation on continued capitalization in certain situations. Subsequent to the issuance of SFAS 19, as a result of the increasing complexity of oil and gas projects due to drilling in remote and deepwater offshore locations, entities increasingly require more than one year to complete all of the activities that permit recognition of proved reserves. In addition, because of new technologies, in certain situations additional exploratory wells may no longer be required before a project can commence.

In April 2005, the FASB issued Staff Position No. 19-1 'Accounting for Suspended Well Costs' (FSP 19-1). FSP 19-1 amends SFAS 19 to permit the continued capitalization of exploratory well costs beyond one year if (a) the well found a sufficient quantity of reserves to justify its completion as a producing well and (b) the entity is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met, or if an entity obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well is assumed to be impaired, and its costs, net of any salvage value, is charged to expense. FSP 19-1 provides a number of indicators that would be considered in order to demonstrate that sufficient progress was being made in assessing the reserves and the economic viability of the project. FSP 19-1 is effective for accounting periods beginning after April 4, 2005. Early application of the guidance is permitted in periods for which financial statements have not yet been issued.

BP's accounting policy is that costs associated with an exploration well are capitalized as an intangible asset until the drilling of the well is complete and the results have been evaluated. If hydrocarbons are found, and, subject to further appraisal activity which may include the drilling of further wells (exploration or exploratory-type stratigraphic test wells), are likely to be capable of commercial development, the costs continue to be carried as an asset. All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off. When proved reserves of oil and natural gas are determined and development is sanctioned, the relevant expenditure is transferred to tangible production assets. We have adopted the FSP with effect from January 1, 2004. No previously capitalized costs were expensed upon the adoption of the FSP.

Accounting changes and error corrections: In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154 'Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3' (SFAS 154). SFAS 154 applies to all voluntary changes in accounting principle and changes the requirements for the accounting for and reporting of a change in accounting principle. SFAS 154 requires retrospective application to prior period financial statements of a voluntary change in accounting principle unless it is impracticable. Previously, most voluntary changes in accounting principle were recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. SFAS 154 also requires that a change in the method of depreciation, amortization or depletion for long-lived nonfinancial assets be accounted for as a change in accounting estimate that is effected by a change in accounting principle. Previously, such changes were reported as a change in accounting principle. SFAS 154 is effective for accounting changes and corrections of errors made in accounting periods beginning after December 15, 2005. The adoption of SFAS 154 is not expected to have a significant effect on profit, as adjusted to accord with US GAAP, or BP shareholders' interest, as adjusted to accord with US GAAP.

ITEM 6 DIRECTORS, SENIOR MANAGEMENT AND EMPLOYEES

DIRECTORS AND SENIOR MANAGEMENT

The following lists the Company's directors and senior management as at June 24, 2005.

Name		**Initially elected or appointed**
P D Sutherland	Non-executive chairman (a)	Chairman since May 1997 Director since July 1995
Sir Ian Prosser	Non-executive deputy chairman (a)(b)(c)	Deputy chairman since February 1999 Director since May 1997
The Lord Browne of Madingley	Executive director (group chief executive)	September 1991
R C Alexander	Chief executive, Innovene	April 2002
Dr D C Allen	Executive director (group chief of staff)	February 2003
P B P Bevan	Group general counsel	September 1992
S Bott	Executive vice president, human resources	March 2005
I C Conn	Executive director, (group executive officer, strategic resources)	July 2004
V Cox	Executive vice president, Gas, Power & Renewables	July 2004
Dr A B Hayward	Executive director (chief executive, Exploration and Production)	February 2003
A G Inglis	Deputy chief executive, Exploration and Production	July 2004
J A Manzoni	Executive director (chief executive, Refining and Marketing)	February 2003
Dr B E Grote	Executive director (chief financial officer)	August 2000
J H Bryan	Non-executive director (a)(c)	December 1998
A Burgmans	Non-executive director (a)(d)	February 2004
E B Davis, Jr	Non-executive director (a)(b)(c)	December 1998
D J Flint	Non-executive director (a)(c)	January 2005
Dr D S Julius	Non-executive director (a)(b)	November 2001
Sir Tom McKillop	Non-executive director (a)(b)	July 2004
Dr W E Massey	Non-executive director (a)(d)	December 1998
H M P Miles	Non-executive director (a)(c)(d)	June 1994
M H Wilson	Non-executive director (a)(c)(d)	December 1998

(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.

Mr R L Olver resigned as an executive director on July 1, 2004. Mr C F Knight and Sir Robin Nicholson retired as non-executive directors on April 14, 2005. At the Company's Annual General Meeting (AGM) the following directors retired, and offered themselves for re-election and were duly re-elected: Dr Allen, The Lord Browne of Madingley, Mr J H Bryan, Mr A Burgmans, Mr E B Davis, Jr, Dr B E Grote, Dr A B Hayward, Dr D S Julius, Mr J A Manzoni, Dr W E Massey, Mr H M P Miles, Sir Ian Prosser, Mr M H Wilson and Mr P D Sutherland. Mr I C Conn was appointed as an executive director and Sir Tom McKillop was appointed as a non-executive director on July 1, 2004, and Mr D J Flint was appointed as a non-executive director on 1 January 2005; each offered themselves for election as a director at the AGM and were duly elected.

The biographies of the directors and senior management are set out below.

P D Sutherland, KCMG Peter Sutherland (59) rejoined BP's board in 1995, having been a non-executive director from 1990 to 1993, and was appointed chairman in 1997. He is non-executive chairman of Goldman Sachs International and a non-executive director of The Royal Bank of Scotland Group p.l.c.

Sir Ian Prosser Sir Ian (61) joined BP's board in 1997 and was appointed non-executive deputy chairman in 1999. He retired as chairman of InterContinental Hotels Group PLC, previously Bass PLC in 2003. He was a non-executive director of The Boots Company from 1984 to 1996, of Lloyds Bank PLC from 1988 to 1995 and of Lloyds TSB Group PLC from 1995 to 1999. In 1999, he was appointed a non-executive director of GlaxoSmithKline and in 2004 he was appointed a non-executive director of Sara Lee Corporation.

The Lord Browne of Madingley, FREng Lord Browne (57) joined BP in 1966 and subsequently held a variety of Exploration and Production and Finance posts in the US, UK and Canada. He was appointed an executive director in 1991 and group chief executive in 1995. He is a non-executive director of Intel Corporation and Goldman Sachs. He was knighted in 1998 and made a life peer in 2001.

R C Alexander Ralph Alexander (50) joined BP in 1982. Since then, he has worked in a variety of roles in BP, including vice president of BP's operations in the Gulf of Mexico, CEO of Air BP and group vice president responsible for new markets development. His most recent post was CEO of BP's Gas, Power & Renewables segment. He was appointed CEO of the Petrochemicals segment in July 2004, transitioning into his current position as CEO of Innovene (BP's new petrochemicals subsidiary).

Dr D C Allen David Allen (50) joined BP in 1978 and subsequently undertook a number of Corporate and Exploration and Production roles in London and New York. He moved to BP's Corporate Planning function in 1986, becoming group vice president in 1999. He was appointed an executive vice president and group chief of staff in 2000 and an executive director of BP in 2003.

P B P Bevan Peter Bevan (61) joined BP after qualifying as a solicitor with a City of London firm. He worked initially in the law department of BP Chemicals. He became group general counsel in 1992 following roles as manager of the Legal function of BP Exploration, assistant company secretary and deputy group legal adviser. He was appointed an executive vice president of BP p.l.c. in 1998.

S Bott (56) joined BP in March 2005 as an executive vice president responsible for human resources management. She joined Citibank in 1970 and following a variety of roles, was appointed a Vice President in human resources in 1979 subsequently holding a series of positions as a human resources director to sectors of Citibank. In 1994, she joined BZW, an investment bank, as head of human resources and in 1996 became group human resources director of Barclays Group. From 2000 to early 2005, she was managing director and head of global human resources at Marsh Inc., insurance brokers.

I C Conn Iain Conn (42) joined BP in 1986. Following a variety of roles in oil trading, refining, commercial marketing, Exploration and Production, in 2000 he became group vice president of BP's Refining and Marketing business. From 2002 to 2004, he was chief executive of Petrochemicals. He was appointed group executive officer with a range of regional and functional responsibilities and an executive director in July 2004. He was appointed to the board of Rolls-Royce Group plc in January 2005.

V Cox Vivienne Cox (45) joined BP in 1981. Following a series of commercial roles, she was appointed chief executive of Air BP in 1998. From 1999 until 2001 she was group vice president in BP Oil responsible for business to business marketing in oil, supply and trading. In 2001, she became group vice president integrated supply and trading (IST) and in 2004 she was appointed an executive vice president, additionally responsible for Gas, Power and Renewables

Dr B E Grote Byron Grote (57) joined BP in 1987 following the acquisition of The Standard Oil Company of Ohio, where he had worked since 1979. He became group treasurer in 1992 and in 1994 regional chief executive in Latin America. In 1999, he was appointed an executive vice president of Exploration and Production, and chief executive of Chemicals in 2000. He was appointed an executive director of BP in 2000 and chief financial officer in 2002.

Dr A B Hayward Tony Hayward (48) joined BP in 1982. He became a director of Exploration and Production in 1997, the segment in which he had previously held a series of roles. In 2000, he was made group treasurer and an executive vice president in 2002. He was appointed chief operating officer for Exploration and Production in 2002 and an executive director of BP in 2003. He is a non-executive director of Corus Group.

A G Inglis Andrew Inglis (46) joined BP in 1980 working on various North Sea Projects. Following a series of commercial roles in BP Exploration, in 1996 he became chief of staff, Exploration and Production. From 1997 until 1999, he was responsible for leading BP's activities in the Deepwater Gulf of Mexico. In 1999, he was appointed vice president of BP's US western gas business unit and in 2004 he became executive vice president and deputy chief executive of Exploration and Production.

J A Manzoni John Manzoni (45) joined BP in 1983. He became group vice president for European marketing in 1999 and BP regional president for the eastern US in 2000. In 2001, he became an executive vice president and chief executive for Gas and Power. He was appointed chief executive of Refining and Marketing in 2002 and an executive director of BP in 2003. He is a non-executive director of SABMiller plc.

J H Bryan John Bryan (68) joined BP's board in 1998, having previously been a director of Amoco. He serves on the boards of General Motors Corporation and Goldman Sachs. He retired as chairman of Sara Lee Corporation in 2001. He is chairman of Millennium Park Inc. in Chicago.

A Burgmans Antony Burgmans (58) joined BP's board in 2004. He was appointed to the board of Unilever in 1991. In 1999, he became chairman of Unilever NV and vice chairman of Unilever PLC. He is also a member of the supervisory board of ABN AMRO Bank NV.

E B Davis, Jr Erroll B Davis, Jr (60) joined BP's board in 1998, having previously been a director of Amoco. He is chairman and chief executive officer of Alliant Energy, a member of the advisory board of the Federal Reserve Bank of Chicago and a non-executive director of PPG Industries, Union Pacific Corporation and the US Olympic Committee.

D J Flint Douglas Flint (49) joined BP's board in January 2005. He trained as a chartered accountant and became a partner at KPMG in 1988. In 1995, he was appointed group finance director of HSBC Holdings p.l.c. He is chairman of the Financial Reporting Council's review of the Turnbull Guidance on Internal Control. Between 2001 and 2004, he served on the Accounting Standards Board and the Standards Advisory Council of the International Accounting Standards Board.

Dr D S Julius, CBE DeAnne Julius (56) joined BP's board in 2001. She began her career as a project economist with the World Bank in Washington. From 1986 until 1997, she held a succession of posts, including chief economist at British Airways and Royal Dutch Shell Group. From 1997 to 2001, she was a full-time member of the Monetary Policy Committee of the Bank of England. She is chairman of the Royal Institute of International Affairs and a non-executive director of Lloyds TSB Group PLC, Serco and Roche Holdings SA.

Sir Tom McKillop Sir Tom (62) joined BP's board in July 2004. Sir Tom was appointed chief executive of AstraZeneca PLC after the merger of Astra AB and Zeneca Group PLC in 1999. He was a non-executive director of Lloyds TSB Group PLC until 2004 and is chairman of the British Pharma Group.

Dr W E Massey Walter Massey (67) joined BP's board in 1998, having previously been a director of Amoco. He is president of Morehouse College, a non-executive director of Motorola, Bank of America and McDonald's Corporation and a member of President Bush's Council of Advisors on Science & Technology.

H M P Miles, OBE Michael Miles (69) joined BP's board in 1994. In 1988, he became an executive director of John Swire & Sons Ltd. He was chairman of Swire Pacific between 1984 and 1988. He is chairman of Schroders plc, non-executive chairman of Johnson Matthey Plc and a director of BP Pension Trustees Ltd.

M H Wilson Michael Wilson (67) joined BP's board in 1998, having previously been a director of Amoco. He was a member of the Canadian Parliament from 1979 to 1993 and held various ministerial posts, including Finance, Industry, Science, Technology, and International Trade. He is chairman of UBS Canada and a non-executive director of Manufacturers Life Insurance Company. He is an officer of the Order of Canada.

COMPENSATION

The remuneration committee determines the terms of engagement and remuneration of the executive directors and monitors the policies applied by the group chief executive in remunerating other senior executives.

Reward Policy

A key priority for the remuneration committee in 2004 has been its comprehensive and independent review of all elements of remuneration policy for executive directors prior to seeking specific shareholder approval for renewal of the Executive Directors' Incentive Plan, which expires in 2005. This wide-ranging review sought to address the fundamental bases of the remuneration policies and plans for the executive directors. It involved significant academic research as well as seeking the views of plan participants, major shareholders and professional advisers. The committee focused on seeking to ensure that, in determining remuneration policy, there is a clear link between the Company's purpose, the business plans and executive reward.

As part of its review, the committee developed the following key principles to guide its policy:

- Policy for the remuneration of executive directors shall be determined and regularly reviewed independently of executive management and will set the tone for the remuneration of other senior executives.
- The remuneration structure shall support and reflect BP's stated purpose to maximize long-term shareholder value.
- The remuneration structure shall reflect a just system of rewards for the participants.
- The overall quantum of all potential remuneration components shall be determined by the exercise of informed judgement of the independent remuneration committee, taking into account the success of BP and the competitive global market.
- The majority of the remuneration shall be linked to the achievement of demanding performance targets that are independently set and reflect the creation of long-term shareholder value.
- Assessment of performance shall be quantitative and qualitative and shall include exercise of informed judgement by the remuneration committee within a framework that takes account of sector characteristics and is approved by shareholders.
- The committee shall be proactive in obtaining an understanding of shareholder preferences.
- Remuneration policy and practices shall be as transparent as possible both for participants and shareholders.

Key policy decisions

The committee then reviewed the existing remuneration policies and plans against these principles and made the following key policy decisions:

- The overall quantum of remuneration and the general balance between short-term and long-term elements are to be maintained.
- Salary levels will continue to be reviewed regularly by reference to those in Europe-based top global companies and the US oil and gas sector applying the committee's judgement.

The long-term incentives framework of the existing Executive Directors' Incentive Plan (EDIP) remains sound, although some changes to policy and application are now appropriate. Specific shareholder approval is being sought for renewal of the EDIP for a further five years.

The share element of the EDIP will provide the long-term performance-based component of the executive directors' remuneration package. There is no current intention to make further share options grants.

The majority of the value previously attributed to share options is to be redistributed to the share element, with the remainder going to the annual bonus.

The measure of long-term performance for the share element will be relative total shareholder return (TSR) compared with the other oil majors over three-year periods, with underlying relative performance also being assessed by the committee.

A proportion of the share element for the current group chief executive will be based on long-term personal leadership measures.

To simplify the operation of the EDIP and increase transparency, the share element will use performance shares rather than the current performance units and multiples.

The performance shares will accrue dividends during the performance period.

The current shareholding requirement for executive directors is to be maintained at 5 times the director's base salary, to ensure alignment of their interests with those of shareholders.

The current pension approach based on national policies is to be maintained.

The wider scene, including pay and employment conditions elsewhere in the Group, will be taken into account, especially when determining annual salary increases.

Elements of Remuneration

The executive directors' total remuneration will continue to consist of salary, annual bonus, long-term incentives, pensions and other benefits. This reward structure will be regularly reviewed by the committee to ensure that it is achieving its objectives. In 2005, over three-quarters of executive directors' potential direct remuneration will again be performance-related.

Salary

The committee expects to review salaries in 2005. In doing so, the committee considers both Europe-based top global companies and the US oil and gas sector; each of these groups is defined and analysed by the committee's independent external remuneration advisers. The committee then assesses the market information and advice and applies its judgement in setting the salary levels.

Annual Bonus

Each executive director is eligible to participate in an annual performance-based bonus scheme. The committee reviews and sets bonus targets and levels of eligibility annually.

For 2005, the target level will be increased from 100% to 120% of base salary (except for Lord Browne, for whom, as group chief executive, it is considered appropriate to increase his target from 110% to 130%). These increases reflect part of the value previously attributed to the share option element of their remuneration packages. In normal circumstances, the maximum payment level for substantially exceeding targets will continue to be 150% (165% for the group chief executive) of base salary. In exceptional circumstances, outstanding performance may be recognized by bonus payments moderately in excess of the 150% (and 165%) levels at the discretion of the remuneration committee.

Similarly, bonuses may be reduced where the committee considers that this is warranted and, in exceptional circumstances, bonuses can be reduced to zero.

The committee recognizes that it is responsible to shareholders to use its discretion in a reasonable and informed manner in the best interests of the Group and that it has a corresponding duty to be accountable and transparent as to the manner in which it exercises its discretion. The committee will explain any significant exercise of discretion in the subsequent directors' remuneration report.

The key aim of the revised annual bonus is to ensure that it is closely tied to the annual business plan and that it reflects short-term deliverables towards the creation of long-term shareholder value.

Executive directors' annual bonus awards for 2005 will be based on a mix of demanding financial targets, based on the Group's annual plan and leadership objectives established at the beginning of the year, in accordance with the following weightings:

50% financial measures from the annual plan principally on cash flow.

30% annual strategic metrics and milestones taken from the five-year group business plan. There is a wide range of measures, including those relating to people, safety, environment, technology and organization, as well as operational actions and business development.

20% individual performance against leadership objectives and living the values of the Group which incorporates BP's code of conduct.

In assessing the final outcome of the individual bonuses each year, the committee will also carefully review the underlying performance of the Group in the context of the five-year Group business plan, as well as looking at competitor results, analysts' reports and the views from the chairmen of other BP board committees. All the calculations are reviewed by the auditors.

Long-term Incentives

Long-term incentives will continue to be provided under the EDIP. It will continue to have within its framework three elements: a share element, a share option element and a cash element. The committee does not currently intend to use either the share option or cash elements but, in exceptional circumstances, may do so.

Each executive director participates in the EDIP. The committee's policy, subject to unforeseen circumstances, is that this should continue until the EDIP expires or is renewed in 2010.

The committee's policy continues to be that each executive director should hold shares equivalent in value to 5 times the director's base salary within five years of being appointed an executive director. This policy is reflected in the terms of the EDIP, as shares awarded under the share element will only be released at the end of the three-year retention period (as described below) if the minimum shareholding guidelines have been met.

Share Element

The committee may make conditional share awards (performance shares) to executive directors, which will only vest to the extent that a demanding performance condition imposed by the committee is met at the end of a three-year performance period. As explained above, for 2005 and future years, the committee currently intends that the share element alone will provide the long-term performance-based component of the executive directors' package, and award levels have been adjusted to reflect this.

Share element awards have been made in 2001 to 2004 inclusive using performance units that may convert into ordinary shares at a ratio of up to two shares for each performance unit (full details of which are set out in Compensation   2004 Remuneration for Executive Directors   Long-term Performance-based Components in this Item on page 129). To simplify the operation of the plan and

increase transparency, the award of performance shares will, for 2005 and future years, replace performance units. Vesting of performance shares will be at a maximum ratio of one-for-one. This change will not increase the value of the award levels or make performance conditions easier to achieve.

The maximum number of performance shares that may be awarded to an executive director in any one year will be determined at the discretion of the remuneration committee and will not normally exceed 5.5 times base salary and, in the case of the group chief executive, 7.5 times base salary.

In addition to the performance condition described below, the committee will have an overriding discretion, in exceptional circumstances, to reduce the number of shares which vest (or to provide that no shares vest).

The shares which vest will normally be subject to a compulsory retention period determined by the committee, which will not normally be less than three years. This gives executive directors a six-year incentive structure, and is designed to ensure that their interests are aligned with those of shareholders. Where shares vest under awards made in 2005 and future years, the executive director will receive additional shares representing the value of reinvested dividends on these shares.

For share element awards in 2005, the performance condition will relate to BP's TSR performance against the other oil majors (ExxonMobil, Shell, Total and Chevron) over a three-year period. TSR is calculated by taking the share price performance of a company over the period, assuming dividends to be reinvested in the company's shares. All share prices will be averaged over the three months before the beginning and end of the performance period and will be measured in US dollars. At the end of the performance period, the TSR performance of each of the companies will be ranked to establish the relative total return to shareholders over the period. Shares under the award will vest as to 100%, 70% and 35% if BP achieves first, second or third place respectively; no shares will vest if BP achieves fourth or fifth place.

Extensive research was independently commissioned by the committee into alternative measures of business performance. After careful review of the studies, the committee is satisfied that relative TSR is the most appropriate measure of performance for BP's long-term incentives for executive directors as it best reflects the creation of long-term shareholder value. Relative performance of the peer group is particularly key in order to minimize the influence of sector-specific effects, including oil price.

The committee is convinced that this comparator group, while small, has the distinct advantage of being very clearly comprised of BP's global competitors. Consultation with major shareholders confirmed that this is the group already used by most of them, as well as by management, in assessing BP's comparative performance. The committee will have the discretion to amend this peer group in appropriate circumstances, for example, in the case of any significant consolidations in the industry.

The committee is mindful of the possibility that a simple ranking system may in some circumstances give rise to distorted results in view of the broad similarity of the oil majors' underlying businesses, the small size of the comparator group and inherent imperfections in measurement. To counter this, the committee will have the ability to exercise discretion in a reasonable and informed manner to adjust (upwards or downwards) the vesting level derived from the ranking if it considers that the ranking does not fairly reflect BP's underlying business performance relative to the comparator group.

The exercise of this discretion would be made after a broad analysis of the underlying health of BP's business relative to competitors, as shown by a range of other measures including, but not limited to, return on average capital employed (ROACE), earnings per share (EPS) growth, reserves replacement and cash flow. This will enable a more comprehensive review of long-term performance, with the aims of tempering anomalies created by relying solely on a formula-based approach and ensuring that the objectives of the plan are met.

It is anticipated that the need to use discretion is most likely to arise where the TSR performance of some companies is clustered, so that a relatively small difference in TSR performance would produce a major difference in vesting levels. In these circumstances, the committee will have power to adjust the vesting level, normally by determining an average vesting level for the companies affected by the clustering.

In line with its policy on transparency, the committee will explain any adjustment to the relative TSR ranking in the next directors' remuneration report following the vesting.

The committee may amend the performance conditions if events occur that would make the amended condition a fairer measure of performance and provided that any amended condition is no easier to satisfy.

For 2005, all executive directors will receive performance share awards on the above basis, over a maximum number of shares set by reference to 5.5 times base salary. For awards under the share element in future years, the committee may continue with the same performance condition, or may impose a different condition which it considers to be no less demanding.

As group chief executive, Lord Browne is eligible for performance share awards of up to 7.5 times base salary. The committee has determined that, while the largest part of this should relate to the TSR measure described above, it is appropriate that a specific part (up to 2 times base salary) should be based on long-term leadership measures. These will focus on sustaining BP's financial, strategic and organizational health and will include, but not be limited to, maintenance of BP's performance culture and the continued development of BP's business strategy, executive talent and internal organization. As with the TSR part of his award, this part will be measured over three-year performance periods.

Share element awards made in previous years

For outstanding awards of performance units made under the plans for the periods 2002-2004, 2003-2005 and 2004-2006, the existing performance conditions will apply for the three-year performance periods in each of the plans. The primary measure is BP's shareholder return against the market (SHRAM), which accounts for nearly two-thirds of the potential total award, the remainder being assessed on BP's relative return on ROACE and EPS growth.

BP's SHRAM is measured against the companies in the FTSE All World Oil & Gas Index. Companies within the index are weighted according to their market capitalization at the beginning of each three-year period in order to give greatest emphasis to oil majors. BP's ROACE and EPS growth are measured against ExxonMobil, Shell, Total and Chevron. All calculations are reviewed by the auditors to ensure that they meet an independent objective standard. The relative position of the company within the comparator group determines the number of shares awarded per performance unit, subject to a maximum of two shares per unit.

Share Option Element

The share option element of the EDIP permits options to be granted to executive directors at an exercise price no lower than the market value of a share at the date the option is granted. The committee does not currently intend to use this element.

Cash Element

The cash element allows the committee to grant long-term cash-based incentives. This element was not used during the first five years of the EDIP and the committee would only do so in special circumstances.

Pensions

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

Benefits and Other Share Schemes

Executive directors are eligible to participate in regular employee benefit plans and in all-employee share schemes and savings plans applying in their home countries. Benefits in kind are not pensionable.

Resettlement Allowance

Expatriates may receive a resettlement allowance for a limited period.

2004 Remuneration for Executive Directors

Amounts shown are in the currency received by executive directors. For information, the average exchange rate for 2004 was £1=$1.83. Annual bonus is shown in the year it was earned.

	Annual remuneration					Long term Performance Plan (LTPP)				Grants under EDIP	
						2002-2004 LTPP (awarded in Feb 2005)		2001-2003 LTPP (awarded in Feb 2004)		2004-2006 share element (granted in Feb 2004)	Share option element (granted in Feb 2004)
Summary of 2004 remuneration	**Salary '000**	**2004 annual performance bonus '000**	**Other benefits '000**	**2004 total '000**	**2003 total '000**	**Actual award (shares)(a)**	**Value '000(b)**	**Actual award (shares)**	**Value '000(c)**	**(performance units)(d)**	**(options)(e)**
The Lord Browne of Madingley	£1,382	£2,280	£82	£3,744	£3,277	356,667	£1,905	352,750	£1,457	634,447	1,500,000
Dr D C Allen	£410	£ 615	£11	£1,036	£828	60,000	£320	62,518	£258	188,235	275,000
Mr I C Conn(f)	£200	£ 300	£42	£542		51,750	£276				
Dr B E Grote	$ 841	$1,262		$ 2,103	$ 1,950(g)	136,960	$ 1,381	131,750	$ 1,053	212,669	349,998
Dr A B Hayward	£410	£ 615	£36	£1,061	£829	55,125	£294	54,825	£226	188,235	275,000
J A Manzoni(h)	£410	£ 615	£46	£1,071	£878	60,000	£320	51,170	£211	188,235	275,000
Directors who left the board in 2004											
R L Olver(i)	£292	£ 438	£42	£772	£1,354	147,222	£786	144,500	£597		

(a) Gross award of shares based on a performance assessment by the remuneration committee and on the other terms of the plan. Sufficient shares are sold to pay for tax applicable. Remaining shares are held in trust until 2008, when they are released to the individual.

(b) Based on the closing price of BP shares on February 3, 2005 (£5.34 per share) or the cost of acquiring ADSs ($60.49 per ADS).

(c) Based on the average market price on date of award (£4.13 per share/$47.96 per ADS).

(d)

Performance units granted under the 2004-2006 share element of the EDIP are converted to shares at the end of the performance period. Maximum of two shares per performance unit.

(e)
Options granted in February 2004 have a grant price of £4.22 per share. Dr Grote holds options over ADSs; the above numbers reflect calculated equivalents.

(f)
Reflects remuneration received by Mr Conn since appointment as executive director on July 1, 2004.

(g)
Includes resettlement allowances for Dr Grote of $175,000, which expired in 2003.

(h)
Mr Manzoni also received compensation of £50,000 in 2004 relating to expatriate costs prior to his appointment as an executive director.

(i)

Amounts for Mr Olver reflect the period until his retirement in July 1, 2004.

Salary

Following a review of appropriate comparator groups of Europe-based top global companies and the US oil and gas sector, base salaries for Lord Browne, Dr Allen, Dr Hayward and Mr Manzoni were increased by 5% per annum with effect from July 1, 2004. On his appointment to the board in 2004, Mr Conn's salary was determined by reference to the same comparator groups.

In deciding upon these new salary levels the committee applied its judgement, taking into account the modest market movements in Europe and the US and the fact that no salary increases had been received by the three executive directors appointed in February 2003 since that time.

Dr Grote's salary was increased in the context of the comparative market information by approximately 15% with effect from July 1, 2004 to reflect his expanded senior role following the retirement of Mr Olver.

Annual Bonus

Fifty per cent of the annual bonus awards for 2004 is based on a mix of financial targets (primarily cash from operations) and 50% is based on long-run metrics and wide-ranging milestones that drive performance improvement and measure the continuing delivery of strategy (including production and sales levels, efficiency, cost management, business development, project delivery and technology progress). All the targets were established at the beginning of the year by the remuneration committee. 2004 was an extremely good year. The Group met or exceeded its annual plan in all material respects. The primary financial target, cash from operations, was exceeded. All the key metrics and milestones were delivered, along with some notable successes in relation to Russia and exploration in Egypt and the Gulf of Mexico. Assessment of all the results, including those on people, safety, environment and organization, resulted in awards of 150% of salary for the executive directors. The committee determined that, given the year's excellent performance, it was appropriate that Lord Browne receive 165% of salary, reflecting his higher bonus target level. All calculations have been reviewed by the auditors.

Past Directors

Following his retirement from BP p.l.c., Mr Olver was appointed on July 1, 2004 as a consultant to BP in relation to its activities in Russia. He had previously been appointed as a BP-nominated director of TNK-BP Limited, a joint venture company owned 50% by BP, effective April 20, 2004. Under the consultancy agreement, he received £150,000 in fees in 2004 and, as a director, deputy chairman and chairman of the audit committee of the joint venture company, he received $90,000 in fees from TNK-BP Limited.

Following his retirement in May 2003, Mr. Rodney Chase was engaged as a consultant to BP in relation to the TNK-BP transaction and was appointed as a BP-nominated director of TNK-BP-Limited. Mr Chase's consultancy to BP ended in May 2004 and he left the board of TNK-BP Limited in March 2004. Under the consultancy agreement, he received $250,000 in 2004 and as a director, deputy chairman and chairman of the audit committee of TNK-BP Limited he received $30,000 in fees from that company.

Long-term awards for both former directors of BP p.l.c. are in accordance with scheme rules and are outlined in Compensation   2004 Remuneration for Executive Directors   Long-term Performance-based Components in this Item on page 129.

Long-term Performance-based Components

Share Element of EDIP and Long Term Performance Plans (LTPPs)

Under the share element of the EDIP and the Long Term Performance Plans, performance units were granted at the beginning of the three-year period and converted into an award of shares at the end of the period, depending on performance. There is a maximum of two shares per performance unit. For 2005 and future years, a different grant mechanism will apply (as described in Compensation Elements of Remuneration Long-term Incentives Share Element in this Item on page 123).

For the 2002-2004 share element of the EDIP and the LTPPs, BP's performance was assessed in terms of SHRAM, ROACE and EPS growth. BP's three-year SHRAM was measured against the companies in the FTSE All World Oil & Gas Index. Companies within the index are weighted according to their market capitalization at the beginning of each three-year period in order to give greatest emphasis to oil majors. BP's ROACE and EPS were measured against ExxonMobil, Shell, Total and Chevron. Based on a performance assessment of 75 points out of 200 (0 for SHRAM, 50 for ROACE and 25 for EPS growth), the committee made awards of shares to executive directors as highlighted in the 2002-2004 lines of the table below.

The following table summarizes the LTPPs and share elements of the executive directors' remuneration for 2004.

	LTPP/Share element interests						Interests vested		
				Performance Units (b)					
	Performance period (a)	Date of grant of performance units	Market price of each share at date of grant of performance units £	At Jan 1, 2004	Granted 2004	At Dec 31, 2004	Number of ordinary shares awarded (c)	Share award date	Market price of each share at share award date £
The Lord Browne of Madingley	2001-2003	Feb 19, 2001	5.80	415,000			352,750	Feb 12, 2004	4.13
	2002-2004	Feb 18, 2002	5.73	475,556		475,556	356,667	February 9, 2005	5.49
	2003-2005	Feb 17, 2003	3.96	632,512		632,512			
	2004-2006	Feb 25, 2004	4.25		634,447	634,447			
Dr D C Allen	2001-2003	Mar 12, 2001	5.88	73,550			62,518	Feb 12, 2004	4.13
	2002-2004	Mar 6, 2002	5.99	80,000		80,000	60,000	February 9, 2005	5.49
	2003-2005	Feb 17, 2003	3.96	197,044		197,044			
	2004-2006	Feb 25, 2004	4.25		188,235	188,235			
Dr B E Grote	2001-2003	Feb 19, 2001	5.80	155,000			131,750	Feb 12, 2004	4.13
	2002-2004	Feb 18, 2002	5.73	182,613		182,613	136,960	February 9, 2005	5.49
	2003-2005	Feb 17, 2003	3.96	233,638		233,638			
	2004-2006	Feb 25, 2004	4.25		212,669	212,669			
Dr A B Hayward(d)	2001-2003	Mar 12, 2001	5.88	64,500			54,825	Feb 12, 2004	4.13
	2002-2004	Mar 6, 2002	5.99	73,500		73,500	55,125	February 9, 2005	5.49
	2003-2005	Feb 17, 2003	3.96	197,044		197,044			
	2004-2006	Feb 25, 2004	4.25		188,235	188,235			
J A Manzoni(d)	2001-2003	Mar 12, 2001	5.88	60,200			51,170	Feb 12, 2004	4.13
	2002-2004	Mar 6, 2002	5.99	80,000		80,000	60,000	February 9, 2005	5.49
	2003-2005	Feb 17, 2003	3.96	197,044		197,044			
	2004-2006	Feb 25, 2004	4.25		188,235	188,235			
Directors appointed to the board in 2004									
I C Conn	2001-2003	Mar 12, 2001	5.88	60,200(e)			51,170	Feb 12, 2004	4.13
	2002-2004	Mar 6, 2002	5.99	69,000(e)		69,000	51,750	February 9, 2005	5.49
	2003-2005	Feb 17, 2003	3.96	91,000(e)		91,000			
	2004-2006	Feb 25, 2004	4.25		91,000	91,000			
Directors who left the board in 2004									
R L Olver	2001-2003	Feb 19, 2001	5.80	170,000			144,500	Feb 12, 2004	4.13
	2002-2004	Feb 18, 2002	5.73	196,296		196,296(f)	147,222	February 9, 2005	5.49
	2003-2005	Feb 17, 2003	3.96	274,138		274,138(f)			
Former Directors									
R F Chase	2001-2003	Feb 19, 2001	5.80	205,000			174,250	Feb 12, 2004	4.13
	2002-2004	Feb 18, 2002	5.73	237,037		237,037	177,778	February 9, 2005	5.49
	2002-2004	Mar 13, 2002	6.17	34,994		34,994	26,245	February 9, 2005	5.49
Dr J G S Buchanan	1998-2000	Feb 5, 1998	4.05	159,900			351,453(g)	Feb 12, 2004	4.13
	2001-2003	Feb 19, 2001	5.80	165,000			140,250	Feb 12, 2004	4.13
	2002-2004	Feb 18, 2002	5.73	192,593		192,593	144,445	February 9, 2005	5.49
	2002-2004	Mar 13, 2002	6.17	28,433		28,433	21,325	February 9, 2005	5.49

	LTPP/Share element interests				Interests vested		
W D Ford	2001-2003	Feb 19, 2001	5.80	170,000	144,500	Feb 12, 2004	4.13

(a)
Dr Allen, Dr Hayward and Mr Manzoni continue to have performance units for the performance periods 2001-2003 and 2002-2004 granted under LTPPs, and Mr Conn for the periods 2001-2003 to 2004-2006 inclusive. They are not required to relinquish these rights, which were granted prior to their appointments as executive directors. All other units were granted under the EDIP as explained

in Compensation Elements of Remuneration Long-Term Incentives in this Item on pages 123-125. BP's performance is assessed against the oil sector. For 1998-2000, BP's SHRAM was measured against ExxonMobil, Shell, Total and Chevron. For 2001-2003, BP's SHRAM, ROACE and EPS growth were measured against ExxonMobil, Shell, Total, Chevron, ENI and Repsol. For 2004-2006, BP's SHRAM is measured against companies in the All World Oil & Gas Index and BP's ROACE and EPS growth against ExxonMobil, Shell, Total and Chevron. Each performance period ends on 31 December of the third year.

(b) Represents number of performance units, each having a maximum potential of two shares depending on performance.

(c) Represents awards of shares made at the end of the relevant performance period based on performance achieved under rules of the plan.

(d) Dr Hayward and Mr Manzoni elected to defer to 2005 the determination of whether LTPP awards should be made for the 1999-2001 performance period. As this period ended prior to their appointment as directors, the expected awards are not included in the table.

(e) On appointment to the board of BP p.l.c. on July 1, 2004.

(f) On leaving the board of BP p.l.c. on July 1, 2004.

(g) Dr Buchanan elected to defer to 2004 the determination of whether an award should be made for the 1998-2000 period. This number includes dividends.

Share Options

The table below represents the interests of executive directors in options over ordinary shares during 2004.

	Option type	At Jan 1, 2004	Granted	Exercised	At Dec 31, 2004	Option price	Market price at date of exercise	Date from which first exercisable	Expiry date
The Lord Browne of Madingley	SAYE	4,550			4,550	£ 3.50		Sept 1, 08	Feb 28, 09
	EDIP	408,522			408,522	£ 5.99		May 15, 01	May 15, 07
	EDIP	1,269,843			1,269,843	£ 5.67		Feb 19, 02	Feb 19, 08
	EDIP	1,348,032			1,348,032	£ 5.72		Feb 18, 03	Feb 18, 09
	EDIP	1,348,032			1,348,032	£ 3.88		Feb 17, 04	Feb 17, 10
	EDIP		1,500,000		1,500,000	£ 4.22		Feb 25, 05	Feb 25, 11
Dr D C Allen	EXEC	37,000			37,000	£ 5.99		May 15, 03	May 15, 10
	EXEC	87,950			87,950	£ 5.67		Feb 23, 04	Feb 23, 11
	EXEC	175,000			175,000	£ 5.72		Feb 18, 05	Feb 18, 12
	EDIP	220,000			220,000	£ 3.88		Feb 17, 04	Feb 17, 10
	EDIP		275,000		275,000	$ 4.22		Feb 25, 05	Feb 25, 11
Dr B E Grote (a)	SAR	40,800		40,800		$ 16.63	$ 48.67	Mar 25, 97	Mar 25, 04
	SAR	35,600		35,600		$ 19.16	$ 61.60	Feb 28, 98	Feb 28, 05
	SAR	35,200			35,200	$ 25.27		Mar 6, 99	Mar 6, 06
	SAR	40,000			40,000	$ 33.34		Feb 28, 00	Feb 28, 07
	BPA	10,404			10,404	$ 53.90		Mar 15, 00	Mar 14, 09
	BPA	12,600			12,600	$ 48.94		Mar 28, 01	Mar 27, 10
	EDIP	40,182			40,182	$ 49.65		Feb 19, 02	Feb 19, 08
	EDIP	58,173			58,173	$ 48.82		Feb 18, 03	Feb 18, 09
	EDIP	58,173			58,173	$ 37.76		Feb 17, 04	Feb 17, 10
	EDIP		58,333		58,333	$ 48.53		Feb 25, 05	Feb 25, 11
Dr A B Hayward	SAYE	3,302			3,302	£ 5.11		Sept 1, 06	Feb 28, 07
	EXEC	34,000			34,000	£ 5.99		May 15, 03	May 15, 10
	EXEC	77,400			77,400	£ 5.67		Feb 23, 04	Feb 23, 11
	EXEC	160,000			160,000	£ 5.72		Feb 18, 05	Feb 18, 12
	EDIP	220,000			220,000	£ 3.88		Feb 17, 04	Feb 17, 10
	EDIP		275,000		275,000	£ 4.22		Feb 25, 05	Feb 25, 11
J A Manzoni	SAYE	750		750		£ 4.50	£ 5.04	Sept 1, 04	Feb 28, 05
	SAYE	878			878	£ 4.52		Sept 1, 07	Feb 28, 08
	SAYE	2,548			2,548	£ 3.50		Sept 1, 08	Feb 28, 09
	SAYE		847		847	£ 3.86		Sept 1, 09	Feb 28, 10
	EXEC	12,000			12,000	£ 2.04		Feb 28, 98	Feb 28, 05
	EXEC	34,000			34,000	£ 5.99		May 15, 03	May 15, 10
	EXEC	72,250			72,250	£ 5.67		Feb 23, 04	Feb 23, 11
	EXEC	175,000			175,000	£ 5.72		Feb 18, 05	Feb 18, 12
	EDIP	220,000			220,000	£ 3.88		Feb 17, 04	Feb 17, 10
	EDIP		275,000		275,000	£ 4.22		Feb 25, 05	Feb 25, 11
Directors appointed to the board in 2004									
I C Conn	SAYE	1,050(b)		1,050		£ 4.50	£ 5.04	Sept 1, 04	Feb 28, 05
	SAYE	1,355(b)			1,355	£ 4.98		Sept 1, 05	Feb 28, 06
	SAYE	1,456(b)			1,456	£ 3.50		Sept 1, 08	Feb 28, 09
	SAYE		1,186		1,186	£ 3.86		Sept 1, 09	Feb 28, 10
	EXEC	900(b)			900	£ 5.67		Feb 23, 04	Feb 23, 11
	EXEC	71,350(b)			71,350	£ 5.67		Feb 23, 04	Feb 23, 11
	EXEC	4,356(b)			4,356	£ 5.72		Feb 18, 05	Feb 18, 12
	EXEC	125,644(b)			125,644	£ 5.72		Feb 18, 05	Feb 18, 12
	EXEC	160,000(b)			160,000	£ 3.88		Feb 17, 06	Feb 17, 13
	EXEC		126,000(b)		126,000	£ 4.22		Feb 25, 07	Feb 25, 14
Director who left the board in 2004									

	Option type	At Jan 1, 2004	Granted	Exercised	At Dec 31, 2004	Option price	Market price at date of exercise	Date from which first exercisable	Expiry date
R L Olver	SAYE	2,642			2,642(c)	£ 3.50		Sept 1, 06	Feb 28, 07
	EDIP	71,847			71,847(c)	£ 5.99		May 15, 01	May 15, 07
	EDIP	260,319			260,319(c)	£ 5.67		Feb 19, 02	Feb 19, 08
	EDIP	370,956			247,304(c)(d)	£ 5.72		Feb 18, 03	Feb 18, 09
	EDIP	370,956			123,652(c)(d)	£ 3.88		Feb 17, 04	Feb 17, 10
	EDIP		400,000		(c)(d)	£ 4.22			

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The closing market prices of an ordinary share and of an ADS on 31 December 2004 were £5.08 and $58.40 respectively. During 2004, the highest market prices were £5.56 and $62.10 respectively, and the lowest market prices were £4.13 and $46.65 respectively.

EDIP	Executive Directors' Incentive Plan adopted by shareholders in April 2000 as described in Compensation Elements of Remuneration Long-Term Incentives in this Item on pages 123-125. The grants were made taking into consideration the ranking of the company's TSR against the TSR of the FTSE Global 100 group of companies over the three-year period prior to the grant.
BPA	BP Amoco share option plan, which applied to US executive directors prior to the adoption of the EDIP.
SAR	Stock Appreciation Rights under BP America Inc. Share Appreciation Plan. In keeping with the US market practice, none of the options under the BPA and SAR is subject to performance conditions because they were granted under American plans to the relevant individuals.
SAYE	Save As You Earn employee share option scheme. These options are not subject to performance conditions because this is an all-employee share scheme governed by specific tax legislation.
EXEC	Executive Share Option Scheme. These options were granted to the relevant individuals prior to their appointments as directors and are not subject to performance conditions.

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

(b) On appointment to the board of BP p.l.c. on 1 July 2004.

(c) On leaving the board of BP p.l.c. on 1 July 2004.

(d) Remaining options after deduction of those that lapsed on retirement.

Pensions

In the table below, amounts are shown in the currency received. For information, the average exchange rate for 2004 was £1 = $1.83. Lord Browne, Dr Allen, Mr Conn, Dr Hayward and Mr Manzoni accrued pension benefits in pounds sterling (the currency of payment). Similarly, Dr Grote accrued pension benefits in US dollars.

	Service at Dec 31, 2004	Accrued pension entitlement at Dec 31, 2004	Additional pension earned during the year ended Dec 31, 2004	Transfer value of accrued benefit at Dec 31, 2003 (a) A	Transfer value of accrued benefit at Dec 31, 2004 (a) B	Amount of B-A less contributions made by the director in 2004
			(thousand)			
The Lord Browne of Madingley (UK)	38 years	£944	£45	£13,921	£15,189	£1,268
Dr D C Allen (UK)	26 years	£183	£15	£2,089	£2,264	£175
I C Conn (UK)	19 years	£127	£35	£849	£1,217	£368
Dr B E Grote (US)	25 years	$465	$94	$4,814	$5,529	$715
Dr A B Hayward (UK)	23 years	£188	£18	£1,967	£2,255	£288
J A Manzoni (UK)	21 years	£149	£14	£1,395	£1,595	£200
Director who left the board in 2004						
R L Olver (UK) (b)	31 years	£390		£6,271	£9,098	£2,827

(a) Transfer values have been calculated in accordance with version 8.1 of guidance note GN11 issued by the actuarial profession.

(b) Mr Olver retired on July 1, 2004 and elected to take a lump sum of £905,194 in lieu of part of his entitlement. The figures in the table include the allowance for this lump sum.

UK Directors

UK directors are members of the regular BP Pension Scheme. 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; and a dependant's benefit of two-thirds of the member's pension. Bonuses are not pensionable for UK directors. 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.

In accordance with the Company's past practice for executive directors who retire from BP on or after age 55 having accrued at least 30 years' service, Lord Browne remains eligible for consideration for a payment from the company of an ex-gratia lump-sum superannuation payment equal to one year's base salary following his retirement. All matters relating to such superannuation payments are considered by the remuneration committee. Any such payment would be additional to his pension entitlements referred to above. No other executive director is eligible for consideration for a superannuation payment on retirement, as the remuneration committee decided in 1996 that appointees to the board after that time should cease to be eligible for consideration for such a payment.

The UK government has announced important proposals on pensions, the impact of which will be reviewed further by the committee in 2005 in conjunction with studies being carried out by the

Company into the wider effects of the new legislation for employees. The intention is that the approach to the new legislation should be consistent for directors and other employees. The committee will report further on the outcome of these studies in the next remuneration report.

US Directors

Dr Grote as a US director participates in the US BP Retirement Accumulation Plan (US plan), which features a cash balance formula. The current design of the US plan became effective on 1 July 2000.

Consistent with US tax regulations, pension benefits are provided through a combination of tax-qualified and non-qualified benefit restoration plans, as applicable.

The Supplemental Executive Retirement Benefit (supplemental plan) is a non-qualified top-up arrangement that became effective on January 1, 2002 for US employees above a specified salary level.

The benefit formula is 1.3% of final average earnings, which comprise base salary and bonus in accordance with standard US practice (as specified under the qualified arrangement) multiplied by years of service, with an offset for benefits payable under all other BP qualified and non-qualified pension arrangements. This benefit is unfunded and therefore paid from corporate assets.

Dr Grote is an eligible participant under the supplemental plan, and his pension accrual for 2004 includes the total amount that may become payable under all plans.

Executive Directors' Shareholdings

Executive directors' interest in BP ordinary shares or calculated equivalents	At January 1, 2004 or on appointment	At December 31, 2004	At June 28, 2005
Current directors			
Dr D C Allen	371,365	408,342	443,742(a)
The Lord Browne of Madingley	1,816,054	2,031,279	2,241,712(b)
I C Conn	119,098(c)	121,187	153,389(d)
Dr B E Grote	788,313	888,213	969,021(e)
A B Hayward	121,692	206,084	300,691
J A Manzoni	127,821	196,336	271,161

	At January 1, 2004	At retirement
Director who left the board in 2004		
R L Olver	798,326	884,408(f)

(a) Includes 25,368 shares held as ADSs.

(b) Includes 57,471 shares held as ADSs.

(c) On appointment on July 1, 2004.

(d)

Includes 38,244 shares held as ADSs.

(e)
Held as ADSs

(f)
On leaving the board on July 1, 2004.

In disclosing the above interests to the Company under the Companies Act 1985, directors did not distinguish their beneficial and non-beneficial interests.

Executive directors are also deemed to have an interest in such shares of the Company held from time to time by The BP Employee Share Ownership Plan (No. 2) to facilitate the operation of the Company's option schemes.

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.

Remuneration of Non-Executive Directors

Policy

The board sets the level of remuneration for all non-executive directors within the limit approved from time to time by shareholders. In line with BP's governance policies, the remuneration of the chairman is set by the board rather than by the remuneration committee, since the performance of the chairman is a matter for the board as a whole rather than any one committee.

The board has adopted the following policies to guide its current and future decision-making with regard to non-executive directors' remuneration.

- Within the limits set by the shareholders from time to time, remuneration should be sufficient to attract, motivate and retain world-class non-executive talent.
- Remuneration of non-executive directors is set by the board and should be proportional to their contribution towards the interests of the company.
- Remuneration practice should be consistent with recognized best-practice standards for non-executive directors' remuneration.
- Remuneration should be in the form of cash fees, payable monthly.
- Non-executive directors should not receive share options from the Company.
- Non-executive directors should be encouraged to establish a holding in BP shares broadly related to one year's base fee, to be held directly or indirectly in a manner compatible with their personal investment activities, and any applicable legal and regulatory requirements.

Elements of remuneration

Non-executive directors' pay comprises cash fees, paid monthly, with increments for positions of additional responsibility, reflecting additional workload and consequent potential liability. For all non-executive directors, except the chairman, a fixed sum allowance is paid for transatlantic travel undertaken for the purpose of attending a board or board committee meeting. In addition, non-executive directors receive reimbursement of reasonable travel and related business expenses. No share or share option awards are made to any non-executive director in respect of service on the board.

Letters of appointment

Non-executive directors have letters of appointment, which recognize that, subject to the Articles of Association, their service is at the discretion of the shareholders. All directors stand for re-election at each annual general meeting.

Non-Executive Directors' Annual Fee Structure

The fees paid to non-executive directors are set by the board within the limit set by shareholders in accordance with the Articles. Shareholders approved an increase to this limit at the 2004 AGM. All fees are fixed and paid in pounds sterling. Fees payable to non-executive directors were adjusted as from January 1, 2005.

	2005 £	**2004 £**
	(thousands)	**(thousands)**
Chairman	500(a)	390(a)
Deputy chairman	100(b)	85(b)
Board member	75	65
Committee chairmanship fee	20	15
Transatlantic attendance allowance (c)	5	5

(a) The chairman is not eligible for committee chairmanship fees or transatlantic attendance allowance but has the use of a fully maintained office for company business and a chauffeured car.

(b) The deputy chairman receives a £20,000 (2005: £25,000) increment on top of the standard board fee. In addition, he is eligible for committee chairmanship fees and the transatlantic attendance allowance. The deputy chairman is currently chairman of the audit committee.

(c) This allowance is payable to non-executive directors undertaking transatlantic travel for the purpose of attending a board meeting or board committee meeting.

	2004		**2003**	
Remuneration of Non-Executive Directors	**$ (a)**	**£**	**$ (b)**	**£**
	(thousands)			
J H Bryan	183	100	155	95
A Burgmans (c)	97	53	n/a	n/a
E B Davis, Jr	192	105	147	90
Dr D S Julius	137	75	130	80
C F Knight*	165	90	155	95
Sir Tom McKillop (d)	70	38	n/a	n/a
Dr W E Massey	210	115	179	110
H M P Miles (e)	137	75	130	80
Sir Robin Nicholson (f)*	165	90	155	95
Sir Ian Prosser	201	110	187	115
P D Sutherland	714	390	636	390
M H Wilson	174	95	155	95
Director who left the board in 2004				
F A Maljers (g)	29	16	130	80

(a) Sterling payments converted at the average 2004 exchange rate of £1 = $1.83.

(b) Sterling payments converted at the average 2003 exchange rate of £1 = $1.63.

(c) Appointed on February 5, 2004.

(d) Appointed on July 1, 2004.

(e) Also received £600 in 2003 for serving as a director of BP Pension Trustees Limited. These fees are no longer payable to BP non-executive directors.

(f) Also received £20,000 each year for serving as the board's representative on the BP technology advisory council.

(g) Retired at AGM on April 15, 2004.

* Retired at AGM on April 14, 2005.

Long-Term Incentives (Residual)

Non-executive directors of Amoco Corporation were allocated restricted stock in the Amoco Non-Employee Directors' Restricted Stock Plan by way of remuneration for their service on the board of Amoco Corporation prior to its merger with BP in 1998. On merger, interests in Amoco shares in the plan were converted into interests in BP ADSs. Under the terms of the plan, the restricted stock will vest upon the retirement of the non-executive director having reached age 70 or upon earlier retirement at the discretion of the board. Since the merger, no further entitlements have accrued to any director under the plan.

Amoco Non-Employee Directors' Restricted Stock Plan

The table below sets out the residual entitlements of non-executive directors who were formerly non-executive directors of Amoco Corporation under the Amoco Non-Employee Directors' Restricted Stock Plan.

	Interest in BP ADSs at January 1, 2004 and December 31, 2004 (a)	Date on which director reaches age 70 (b)
J H Bryan	5,546	October 5, 2006
E B Davis, Jr	4,490	August 5, 2014
Dr W E Massey	3,346	April 5, 2008
M H Wilson	3,170	November 4, 2007
Director who left the board in 2004		
F A Maljers	2,906	August 12, 2003(c)

(a) No awards were granted and no awards lapsed during 2004.

(b) For the purposes of the regulations, the date on which the director retires from the board at or after the age of 70 is the end of the qualifying period. If the director retires prior to this date, the board may waive the restrictions.

(c) Mr Maljers retired from the board on April 15, 2004 and, in accordance with the terms of the plan, his awards vested on that date (when the BP ADS closing price was $54.16) without payment by him. These awards over BP ADS derived from awards over Amoco shares granted between April 26, 1994 and April 28, 1998. The awards were granted over Amoco stock prior to the merger but their notional weighted average market value at the date of grant (applying the subsequent merger ratio of 0.66167 of a BP ADS for every Amoco share) was $27.87 per BP ADS.

Superannuation Gratuities

In accordance with the Company's long-standing practice, non-executive directors who retire from the board after at least six years' service are, at the time of their retirement, eligible for consideration for a superannuation gratuity. The board is authorized to make such payments under the Company's Articles. The amount of the payment is determined at the board's discretion (having regard to the director's period of service as a director and other relevant factors).

In 2002, the board revised its policy with respect to such payments so that: (i) non-executive directors appointed to the board after July 1, 2002 would not be eligible for consideration for such a payment; and (ii) while non-executive directors in service at July 1, 2002 would remain eligible for consideration for a payment, service after that date would not be taken into account by the board in considering the amount of any such payment.

The board made no superannuation gratuity payments during 2004.

Non-Executive Directors' Shareholdings

Non-Executive Directors' interest in BP ordinary shares or calculated equivalents	At December 31, 2004	At January 1, 2004 or on appointment	Change from December 31, 2004 to June 28, 2005
A Burgmans (b)	10,000	10,000	
J H Bryan	158,760(a)	158,760(a)	
E B Davis, Jr	66,349(a)	65,162(a)	641
D J Flint (c)			15,000
Dr D S Julius	15,000	15,000	
C F Knight*	98,578(a)	95,610(a)	204
Dr W E Massey	49,722(a)	49,261(a)	
Sir Tom McKillop (d)	20,000		
H M P Miles	22,145	22,145	
Sir Robin Nicholson*	4,020	3,897	32
Sir Ian Prosser	16,301	16,301	
P D Sutherland	30,079	30,079	
M H Wilson	60,000(a)	60,000(a)	

(a) Held as ADSs.

(b) Mr. A Burgmans was appointed February 5, 2004.

(c) Mr D J Flint was appointed January 1, 2005

(d) Sir Tom McKillop was appointed July 1, 2004

* Retired at AGM on April 14, 2005.

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.

Total Remuneration

Total remuneration includes salary and benefits earned and paid during the relevant year, plus bonuses, which are paid in the following year, plus for 2004 the value of the awards made under the 2001 to 2003 LTPP in respect of the three years covered by that plan. The total remuneration paid during 2004 to all directors and senior management as a group (22 persons at December 31, 2004) was $32 million. Total share options granted during 2004 to all directors and senior management as a group was 3,539,998; these have an option price of £4.22 and expire in 2011. The amount accrued during 2004 to provide pension benefits to all directors and senior management as a group was $14 million.

During 2005, the Company will introduce a new Medium Term Performance Plan (MTPP) and a new Deferred Annual Bonus Plan (DABP) for Senior Management. Executive Directors will not participate in either plan. Under the MTPP, Performance Units will be granted at the start of a three-year performance period, representing the maximum potential share award. At the end of this period, shares will be awarded based on BP's performance against two measures and the number of Performance Units granted to the individual. Under the DAPB, shares will be awarded to participants annually to reflect a proportion of the annual cash bonus that their performance has earned. The shares will vest after a three-year retention period. Both plans will have effect from January 1, 2005. The MTPP replaces the existing LTPP element of senior management's total remuneration and, with effect from January 1, 2005, senior management no longer receives annual grants of share options under the BP Share Option Plan.

BOARD PRACTICES

Directors' Terms of Office	Date of expiration of current term of office (a)	Period during which the director has served in this office (from appointment to June 2005)
Dr D C Allen	April 2006	2 years 3 months
The Lord Browne of Madingley	April 2006	13 years 9 months
J H Bryan (b)	April 2006	6 years 6 months
A Burgmans	April 2006	1 year 4 months
I C Conn	April 2006	11 months
E B Davis, Jr (b)	April 2006	6 years 6 months
D J Flint	April 2006	5 months
Dr B E Grote	April 2006	4 years 10 months
Dr A B Hayward	April 2006	2 years 4 months
Dr D S Julius	April 2006	3 years 7 months
Sir Tom McKillop	April 2006	11 months
J A Manzoni	April 2006	2 years 4 months
Dr W E Massey (b)	April 2006	6 years 6 months
H M P Miles	April 2006	11 years 0 months
Sir Ian Prosser	April 2006	8 years 1 month
P D Sutherland (c)	April 2006	9 years 11 months
M H Wilson (b)	April 2006	6 years 6 months

(a) Shareholders approved an amendment to the Articles of Association such that at each AGM held after December 31, 2004, all directors shall retire from office and may offer themselves for re-election. Therefore all directors will retire or offer themselves for re-election in accordance with the Articles of Association at the 2005 AGM.

(b) Does not include service on the board of Amoco Corporation

(c) Mr Sutherland previously served as a director from 1990-1993.

Directors' Service Contracts Providing for Benefits upon Termination of Employment

All service contracts expire at normal retirement date and have a notice period of one year.

The service contracts of Dr Allen, Dr Hayward, Mr Manzoni and Mr Conn may also be terminated by the Company at any time with immediate effect on payment in lieu of notice equivalent to one year's salary or the amount of salary that would have been paid if the contract had terminated on the expiry of the remainder of the notice period.

Dr Grote's service contract is with BP Exploration (Alaska) Inc. He is seconded to BP p.l.c. under a secondment agreement dated August 7, 2000. At December 31, 2004, this secondment agreement had an unexpired term of three years. The secondment may be terminated by one month's notice by either party and terminates automatically on the termination of Dr Grote's service contract.

There are no other provisions for compensation payable on early termination of the above contracts. In the event of early termination under any of the above contracts by the Company other than for cause (or under a specific termination payment provision), the relevant director's then current salary and benefits would be taken into account in calculating any liability of the Company.

Since January 2003, the committee has included a provision in new service contracts to allow for severance payments to be phased, where appropriate to do so. It will also consider mitigation to reduce compensation to a departing director, where appropriate to do so.

Governance and the role of our board

Good governance is often defined in terms of the presence or absence of particular practices without reference to the underlying purpose of governance processes. We believe that governance is a more powerful concept.

Governance is not an exercise in compliance nor is it a higher form of management. Governance lies at the heart of all the board does and it is the task our owners entrust to the board. It has a clear objective ensuring the pursuit of the Company's purpose. The board's role is focused on this task, which is unique to it as the representative of BP's owners. This task is discharged by the board through undertaking such activities as are necessary for the effective promotion of shareholder interest.

Governance is the system by which the Company's owners and their representatives on the board ensure that it pursues, does not deviate from and only allocates resources to its defined purpose.

As a Company, we recognize the importance of good governance and that it is a discrete task from management. Clarity of roles is key to our approach. Policies and processes depend upon the people who operate them. Governance requires distinct skills and processes. In the context of BP, governance is overseen by our board while management is delegated to the group chief executive by means of the board governance policies.

Our board governance policies use a coherent, principles-based approach, which anticipated many developments in UK governance regulation. They ensure that our board and management operate within a clear and efficient governance framework that goes beyond regulatory compliance and places shareholder interest at the heart of all we do.

Accountability to shareholders

Our board is accountable in a variety of ways. It 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 interest of our shareholders.

Our board is accountable to shareholders for the performance and activities of the entire BP Group. It embeds shareholder interest in the goals established for the Company.

In carrying out its work in policy-making and monitoring and in its active consideration of Group strategy, our board exercises judgement on how best to further shareholder interest. The board seeks to do so by maximizing the expected value of shareholders' interest in the Company, not by eliminating the possibility of any adverse outcomes.

Reporting

Our board makes use of a number of formal communication channels to account to shareholders for the performance of the Group. These include the Annual Report and Accounts, the Annual Review, the Annual Report on Form 20-F, quarterly Forms 6-K and announcements made through stock exchanges on which BP shares are listed, as well as through the AGM.

Dialogue with directors

Presentations given at appropriate intervals to representatives of the investment community are available to all shareholders by internet broadcast or open conference call. Less formal processes include contacts with institutional shareholders by the chairman and other non-executive directors. This is supported by the dialogue with shareholders concerning the governance and operation of the Group maintained by the company secretary's office, investor relations and other BP teams.

AGM and voting

Given the size and geographical diversity of our shareholder base, the opportunities for shareholder interaction at the AGM are limited. However, the chairman and all board committee chairmen were present at the 2004 and 2005 AGMs to answer shareholders' questions and hear their views during the meeting. Members of the board met informally with shareholders afterwards. All votes at shareholder meetings, whether by proxy or in person, are counted since votes on all matters, except procedural issues, are taken by way of a poll. We have pioneered the use of electronic communications to facilitate the exercise of shareholder control rights and continue to promote the use of electronic voting through our registrar's website and through CREST.

Directors' elections

Directors are required to stand for re-election each year. New directors are subject to election at the first opportunity following their appointment. All names submitted to shareholders for election are accompanied by detailed biographies.

How our board governs the Company

The board's governance policies regulate its relationship with shareholders, the conduct of board affairs and the board's relationship with the group chief executive. The policies recognize the board's separate and unique role as the link in the chain of authority between the shareholders and the group chief executive. It is this unique task that gives the board its central role in governance.

The dual role played by the group chief executive and executive directors as both members of the board and leaders of the executive management is also recognized and addressed. The policies require a majority of the board to be composed of independent non-executive directors. To assure the integrity of the governance process, the relationship between the board and the group chief executive is governed by the non-executive directors, particularly through the work of the board committees they populate.

Recognizing that as a group its capacity is limited, our board reserves to itself the making of broad policy decisions. It delegates 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 activities). The board governs BP through setting general policy for the conduct of business (and critically, by clearly articulating its objective) and by monitoring its implementation by the group chief executive.

To discharge its governance function in the most effective manner, our board has laid down rules for its own activities in a board process policy. The board process policy covers:

- The conduct of members at meetings;
- The cycle of board activities and the setting of agendas;
- The provision of timely 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 evaluation and assessment of board performance;

The remuneration of non-executive directors;

The process for directors to obtain independent advice; and

The appointment and role of the company secretary.

The responsibility for implementation of this policy is placed on the chairman.

The board-executive linkage 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 and required results 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. This policy addresses internal control, risk preferences, financing, ethical behaviour, health, safety, the environment, treatment of employees and political considerations. Through the goals and executive limitations policies, the board shapes BP's values and standards.

Accountability in our business

Our group chief executive outlines how he intends to deliver the required outcome in annual and medium-term plans, which also address a comprehensive assessment of the Group's risks. Progress towards the expected outcome forms the basis of a report to the board that covers actual results and a forecast of results for the current year. This report is reviewed at each board meeting.

The group chief executive is obliged through dialogue and systematic review to discuss with our board all material matters currently or prospectively affecting the Company and its performance and all strategic projects or developments. This key dialogue specifically includes any materially under-performing business activities and actions that breach the executive limitations policy and material matters of a social, environmental and ethical nature.

The board-executive linkage 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 systems set out in the board-executive linkage policy are designed to manage, rather than to 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.

Who is on the board?

Governance policies and processes depend upon the quality and commitment of the people who operate them.

The board is composed of the chairman, 12 non-executive and six executive directors. In total, five nationalities are represented on the board. Directors' biographies are set out in Directors and Senior Management in this Item on pages 118-120. As reported last year, the board is actively engaged in succession planning issues. As a result, the size of the board has increased during the past year despite the departure of Mr Maljers and Mr Olver. Mr Burgmans (February), Sir Tom McKillop (July) and Mr Flint (from January 2005) were appointed as non-executive directors, while Mr Conn joined the board as an executive director in July.

The efficiency and effectiveness of the board are paramount concerns. Our board is large but this is necessary to allow sufficient executive director representation to cover the breadth of the Group's business activities and sufficient non-executive representation to reflect the scale and complexity of BP and to staff our board committees. A board of this size allows orderly succession planning for key roles.

We believe refreshing the composition of the board should be an orderly process of evolution that ensures its continuing effectiveness. New non-executive directors will be appointed over the coming years. Mr Knight and Sir Robin Nicholson retired at the 2005 AGM. Mr Miles will retire in 2006 and subject to their annual re-election, Mr Bryan and Mr Wilson in 2007.

Board independence

The qualification for board membership includes a requirement that all our 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 our non-executive directors fulfil this requirement. It determined all 12 who served during 2004 to be independent directors.

Mr Knight and Sir Robin Nicholson were appointed to the BP board in 1987 and Mr Miles was appointed in 1994. The length of their respective service on the board exceeds the nine years referred to in the Combined Code. The board considers that the experience and long-term perspective of each of these directors on BP's business during its recent period of growth provide a valuable contribution to the board, given the long-term nature of our business. The integrity and independence of character of these directors are beyond doubt. Both Mr Knight and Sir Robin retired at the 2005 AGM. Mr Miles will retire in 2006.

Those directors who joined the BP board in 1998 after service on the board of Amoco Corporation (Messrs Bryan, Massey, Wilson and Davis) are considered independent since the most senior executive management of BP comprises individuals who were not previously Amoco employees. While Amoco businesses and assets are a key part of the Group, the scope and scale of BP since its acquisition of the ARCO, Burmah Castrol and Veba businesses are fundamentally different from those of the former Amoco Corporation.

The board has satisfied itself that there is no compromise to the independence of those directors who serve together as directors on the boards of outside entities (or who have other appointments in outside entities). Where necessary, our board ensures appropriate processes are in place to manage any possible conflict of interest.

Sir Robin Nicholson received fees during 2004 for representing the board on the BP technology advisory council. Since these fees relate to board representation, they did not compromise Sir Robin's independence. Full details of these fees are disclosed in Compensation Remuneration of Non-Executive Directors in this Item on page 136.

Directors' appointments, retirement policies and insurance

The chairman and non-executive directors of BP are elected each year and, subject to BP's Articles of Association, serve on the basis of letters of appointment. Executive directors of BP have service contracts with the Company. Details of all payments to directors are set out in Compensation in this Item on pages 121-138.

Annual elections for all directors and the provision of independent support to our board and board committees underscore our commitment to good governance practice.

BP's policy on directors' retirement is as follows: executive directors retire at age 60, while non-executive directors ordinarily retire at the AGM following their 70th birthday. It is the board's policy that non-executive directors are not generally expected to hold office for more than 10 years.

In accordance with BP's Articles of Association, directors are granted an indemnity from the Company to the extent permitted by law in respect of liabilities incurred as a result of their office. In respect of those liabilities for which directors may not be indemnified, the Company purchased and maintained a directors' and officers' liability insurance policy throughout 2004. This insurance cover was renewed at the beginning of 2005. Neither the Company's indemnity nor insurance provides cover in the event that the director is proved to have acted fraudulently or dishonestly.

Board and committees: meetings and attendance

In addition to the AGM (which all but one director attended), the board met eight times during 2004, five times in the UK, twice in the US and once in continental Europe. Two of these meetings were two-day strategy discussions. 2004 saw an increased number of committee meetings, with no sign that this trend will reverse.

The board requires all members to devote sufficient time to the work of the board to discharge the office of director and to use their best endeavours to attend meetings. During 2004, directors attended at least 75% of meetings, except Mr Burgmans. Several board meetings coincided with commitments entered into by Mr Burgmans before his appointment to the board in February 2004, a matter made known to the board on his appointment. The board and Mr Burgmans are looking forward to his full participation in the years ahead.

Serving as a director: induction, training and evaluation

Induction

Directors receive induction on their appointment to the board as appropriate, covering matters such as the operation and activities of the Group (including key financial, business, social and environmental risks to the Group's activities), the role of the board and the matters reserved for its decision, the tasks and membership of the principal board committees, the powers delegated to those committees, the board's governance policies and practices, and the latest financial information about the Group. The chairman is accountable for the induction of new board members.

Training

Our directors are updated on BP's business, the environment in which it operates and other matters throughout their period in office. We advise directors on their appointment of the legal and other duties and obligations they have as directors of a listed company. The board regularly considers the implications of these duties under our board governance policies. Our non-executive directors receive training specific to the tasks of the particular board committees on which they serve.

Outside appointments

As part of their ongoing development, our executive directors are permitted to take up an external board appointment, subject to the agreement of our board. Executive directors retain any fees received in respect of such external appointments.

Generally outside appointments for executive directors are limited to one outside company board only, although our group chief executive, by exception, serves on two outside company boards. Our board is satisfied that these appointments do not conflict with his duties and commitment to BP. Non-executive directors may serve on a number of outside boards, always provided they continue to demonstrate the requisite commitment to discharge effectively their duties to BP. The nomination committee keeps the extent of directors' other interests under review to ensure that the effectiveness of our board is not compromised.

Evaluation

During 2004, our board continued its ongoing evaluation processes to assess its performance and identify areas in which its effectiveness, policies or processes might be enhanced. The board reviewed the conclusions and actions from the 2003 evaluation and determined that there should be a focus on evaluating the performance of the board committees during 2004.

Regular evaluation of board effectiveness underpins our confidence in BP's governance policies and processes and affords opportunity for their development.

Evaluations of both the audit and the ethics and environment assurance committees took place during 2004. An evaluation of the work of the remuneration committee will take place in 2005 as the review of executive remuneration is concluded and Dr Julius has assumed chairmanship of the committee. Work on a further evaluation of the board and the performance of individual directors has commenced.

The chairman and senior independent director

BP's board governance policies require the chairman and deputy chairman to be non-executive directors; throughout 2004 the posts were held by Mr Sutherland and Sir Ian Prosser respectively. Sir Ian also acts as our senior independent director and is the director whom shareholders may contact if they feel their concerns are not being addressed through normal channels.

Between board meetings, the chairman has responsibility for ensuring the integrity and effectiveness of the board/executive relationship. This requires his interaction with the group chief executive between board meetings, as well as his contact with other board members and shareholders. The chairman represents the views of the board to shareholders on key issues, not least in succession planning issues for both executive and non-executive appointments. The chairman and all the non-executive directors meet periodically as the chairman's committee (see Board Practices Chairman's committee report in this Item on page 149). The performance of the chairman is evaluated each year at a meeting of the chairman's committee, for which item of business he is not present. The company secretary reports to the chairman and is not part of the executive management.

Board committees

The board process policy allocates the tasks of monitoring executive actions and assessing performance to certain board committees. These tasks, rather than any terms of reference, prescribe the authority and the role of the board committees. Reports for each of the committees for 2004 appear below. In common with the board, each committee has access to independent advice and counsel as required and each is supported by the company secretary and his office, which is demonstrably independent of the executive management of the Group.

Audit committee report

Schedule and composition

The committee met 13 times during 2004 and comprised the following directors: Sir Ian Prosser (chairman), J H Bryan, E B Davis, Jr, H M P Miles, M H Wilson.

All members of the audit committee are independent non-executive directors. The board considers that the membership of the audit committee as a whole has sufficient recent and relevant financial experience to discharge its functions, but it has determined that during 2004 no one member of the audit committee had all the attributes of an audit committee financial expert as defined for purposes of disclosure Item 16A of Form 20-F. The Company did not have an audit committee financial expert because the board considered that the membership of the audit committee as a whole had sufficient recent and relevant financial experience to discharge its functions

Douglas Flint joined the board as a non-executive director on January 1, 2005 and joined the audit committee on March 16, 2005. He is group finance director of HSBC Holdings plc, and former member of the Accounting Standards Board and the Standards Advisory Council of the International Accounting Standards Board. The board determined that with effect from March 16, 2005 Mr Flint may be regarded as an audit committee financial expert as defined for purposes of disclosure Item 16A of Form 20-F.

The external auditors' lead partner, the BP general auditor (head of internal audit), together with the group chief financial officer, the chief accounting officer and the group controller, attend each meeting at the request of the committee chairman. At least twice a year, the committee meets with the external auditor without the executive management being present. The committee also meets in private session with the general auditor.

Role and authority

The audit committee's tasks are considered by the committee to be broader than those envisaged under UK Combined Code Provision C.3.2. The committee is satisfied that it addresses each of those matters identified as properly falling within an audit committee's purview. The committee has full delegated authority from the board to address those tasks assigned to it. In common with the board and all committees, it may request any information from the executive management necessary to discharge its functions and may, where it considers necessary, seek independent advice and counsel.

Process

The committee structures its work programme so as to discharge its tasks, which include systematic monitoring and obtaining assurance that the legally required standards of disclosure are being fully and fairly observed and that the executive limitations relating to financial matters are being observed. The committee chairman reports on the committee's activities to the board meeting immediately following a committee meeting. Between meetings, the committee chairman reviews emerging issues with the group chief financial officer, the external auditor and the BP general auditor. He is supported in this task by the company secretary's office.

During 2004, external specialist legal and regulatory advice has also been provided to the committee by Sullivan & Cromwell LLP. With significant changes in accounting practices being introduced in 2005, the committee undertook initial training in the implementation of International Financial Reporting Standards (IFRS) and how these standards are expected to affect the Group's reported results.

Activities in 2004

Financial reports

During the year, the committee reviewed all annual and quarterly financial reports before recommending their publication on behalf of the board. In particular, the committee discussed significant accounting policies, estimates and judgements that had been applied in preparing these reports and received independent advice from the external auditors.

Accounting treatment

The committee also received during the year separate reports concerning the Group's environmental and decommissioning provisions, tax exposures, pension assumptions and the status of current litigation. The committee gained assurance that such liabilities and contingencies were appropriately reflected in the financial results.

System of internal control

Each year, specific reports on risk management and internal control within selected business and functional activities are considered. During 2004, the Exploration and Production and Petrochemicals segments were reviewed, along with accounting issues of the supply and trading function that services all BP's businesses. Given the increased public and regulatory attention to hydrocarbon reserves reporting, the committee sought and received additional assurance that BP's management and recording processes are applied in a consistent and coherent manner throughout the Group. Following the adoption of the US Sarbanes-Oxley Act of 2002, an increased regulatory requirement has been placed on all companies that offer shares by listing on US stock exchanges. The committee has monitored the Company's response to the applicable requirements of this Act and, in particular, its progress in evaluating internal controls as required by rules pursuant to Section 404 of the Act.

Employee concerns reporting/whistleblowing

The committee receives regular reports of the matters raised through the employee concerns programme (OpenTalk) and, through this process, is alerted to instances of potential fraud or matters of concern raised related to the finances and financial accounting policies of the Group.

Auditor independence and rotation

The committee reviews on behalf of the board the independence, objectivity and viability of the auditors before an appointment recommendation is made to shareholders at the AGM. A new lead audit partner is appointed every five years and other senior audit staff are rotated every seven years.

Policy on non-audit services provided by the auditor

To safeguard the independence of the audit process, non-audit services provided by the auditor are limited to defined audit-related work and tax services that fall within specific categories. Additionally, all such services must be pre-approved by the committee. These services have been substantially reduced in 2004 but overall fees paid to Ernst & Young have increased, since audit fees have risen significantly across the market due to the increased regulatory burden on listed companies.

Internal audit

The committee considers the internal auditor's programme and its effectiveness twice a year. It receives regular reports of work undertaken, actions recommended and the executive management's responses to those recommendations.

Performance evaluation

Each year the committee critically reviews its own performance and considers where improvements can be made. During 2004, the committee strengthened its tracking of outstanding issues and clarified the scope of its role and relationship with that of the ethics and environment assurance committee. It also allocated additional time to training, not least on the implications of the introduction of IFRS. To accommodate all such matters and discharge its ongoing tasks the committee increased the number of meetings from nine in 2003 to 13 in 2004.

Ethics and environment assurance committee report

Schedule and composition

The committee met six times during 2004 and comprised the following directors: Dr W E Massey (chairman), A Burgmans (from October 2004), F A Maljers (to April 2004), H M P Miles, M H Wilson.

All members of the ethics and environment assurance committee are independent non-executive directors. The external auditors' lead partner and the BP general auditor (head of internal audit) attend each meeting at the request of the committee chairman. The committee met once during 2004 with the general auditor and external auditor but without the executive management being present.

Role and authority

The task of the committee is to monitor matters relating to the executive management's processes to address environmental, health and safety, security and ethical behaviour issues. The committee monitors the observance of the executive limitations relating to non-financial risks to the Group.

Process and activities in 2004

At each meeting, the committee considered a report from executive management on current developments in business and functional areas giving rise to ongoing and emergent non-financial risks to the Group's activities. In particular, during the course of 2004, the committee directed its attention to the BTC pipeline project and operations in Alaska and Russia. The committee's work programme also addressed:

Environmental liabilities

Including a review of the Group's approach to remediation at operational and disused sites, encompassing all businesses ranging from mining activities to oil terminals to service stations.

Health, safety and environmental performance

Greenhouse gas and other emissions, spills and containment practices and safety at work issues, both group-wide and in specific businesses and locations (for example, shipping, road safety and the operational integrity of plant and equipment).

Security

Group preparedness and mitigation plans in respect of identified and potential security threats to staff, physical infrastructure and the digital infrastructure of the Group.

Employees

The results of the annual People Assurance Survey, employee health and welfare and the impact of HIV/AIDS on our business.

Ethical behaviour

Matters arising from the annual ethics certification process and OpenTalk (BP's employee concerns reporting programme), as well as other conduct and compliance issues.

Disaster recovery and business continuity planning and capability

Development of the Group's capacity and capability to respond to catastrophic events and to maintain its business activities.

Performance evaluation

The committee addressed the nature of its remit and authority, its interface with the audit committee and the scope and focus of its activities, as well as its overall effectiveness and refinements to its processes. The committee increased the number of its meetings from five in 2003 to six in 2004.

Remuneration committee report

Schedule and composition

The committee met seven times during 2004 and comprised the following directors: Sir Robin Nicholson (chairman, retired at the 2005 AGM), Dr D S Julius (chairman elect), E B Davis, C F Knight (retired at the 2005 AGM), Sir Ian Prosser, J H Bryan (from November 2004), Sir Tom McKillop (from November 2004).

All members of the remuneration committee are non-executive directors and are considered by the board to be independent. The chairman of the board also attends committee meetings. The committee is independently advised.

Role and authority

The committee's main task is to determine the terms of engagement and remuneration of the executive directors. A key priority for the committee in 2004 was its review of executive directors' remuneration policy in preparation for the renewal of the long-term incentive plan for executive directors at the 2005 AGM.

Remuneration Committee Report

Full details of executive directors' remuneration is set out in Compensation in this Item on pages 121-138.

Chairman's committee report

Schedule and composition

The chairman's committee met three times during 2004 and comprised all the non-executive directors.

Role and authority

The task of the committee is to consider broad issues of governance, including the performance of the chairman and the group chief executive, succession planning, the organization of the Group and any matters referred to it for an opinion from another board committee.

Process and activities in 2004

At its various meetings, the committee evaluated the performance of the chairman and the group chief executive, considered the plan for executive succession and considered a number of other broad matters of governance, including the future governance of the Olefins and Derivatives business as it is prepared for its planned disposal. Additionally, the committee addressed non-executive succession planning issues in co-ordination with the nomination committee.

Nomination committee report

Schedule and composition

The committee met twice during 2004 and comprised the following directors: P D Sutherland (chairman), Dr W E Massey, Sir Robin Nicholson, Sir Ian Prosser. All members of the nomination committee are considered by the board to be independent.

Role and authority

The task of the nomination committee is to identify and evaluate candidates for appointment and reappointment as director or company secretary of BP.

Process

During the year, the nomination committee carried out a detailed review of the skills and expertise of the non-executive directors as part of the board succession planning described earlier. The committee receives external assistance as required. The committee consults with the group chief executive concerning the identification and appointment of new executive directors.

Activities in 2004

The committee considered the composition of the board and board committees in the context of forthcoming work programmes, BP's strategy and business activities and retirements from the board. Board and committee evaluation processes informed its work in identifying the skills and experience sought from potential candidates.

External search consultants were retained in the UK, continental Europe and the US to assist the committee in the identification of potential candidates as non-executive directors. In close co-ordination with the chairman's committee (all the non-executive directors), the nomination committee recommended the appointment of the following directors during the year: Sir Tom McKillop, I C Conn and D J Flint.

EMPLOYEES

	UK	Rest of Europe	USA	Rest of World	Total
Number of employees at December 31, 2004					
Exploration and Production	2,900	650	5,000	7,100	15,650
Refining and Marketing	10,200	18,800	25,300	12,950	67,250
Petrochemicals	2,350	5,750	3,500	800	12,400
Gas, Power and Renewables	200	800	1,450	1,600	4,050
Other businesses and corporate	1,750		1,700	100	3,550
	17,400	26,000	36,950	22,550	102,900
2003					
Exploration and Production	3,000	650	4,650	6,850	15,150
Refining and Marketing	10,050	17,850	25,700	12,550	66,150
Petrochemicals	2,500	5,950	6,150	1,350	15,950
Gas, Power and Renewables	200	800	1,350	1,400	3,750
Other businesses and corporate	1,300		1,250	150	2,700
	17,050	25,250	39,100	22,300	103,700
2002					
Exploration and Production	3,500	800	5,300	7,000	16,600
Refining and Marketing	9,950	22,250	28,100	12,000	72,300
Petrochemicals	2,800	5,800	6,650	3,700	18,950
Gas, Power and Renewables	250	1,000	1,700	1,650	4,600
Other businesses and corporate	1,250		1,450	100	2,800
	17,750	29,850	43,200	24,450	115,250

Employee numbers decreased in 2003 compared with 2002, with 21% of the decrease resulting from the disposal of Fosroc Mining, 20% from the reduction of service station staff in the US, 17% from the transfer of employees in Russia into TNK-BP and 12% from reorganization of Refining and Marketing operation in Germany.

The Company seeks to maintain constructive relationships with labour unions.

SHARE OWNERSHIP

Directors and Senior Management

As at June 28, 2005 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:

Dr D C Allen	443,742	436,623(b)
The Lord Browne of Madingley	2,241,712	2,006,767(b)
I C Conn	153,389	415,832(b)
Dr B E Grote	969,021	501,780(b)
Dr A B Hayward	300,691	436,623(b)
J A Manzoni	271,161	436,623(b)
J H Bryan	158,760	
A Burgmans	10,000	
E B Davis, Jr	66,990	
D J Flint	15,000	
Dr D S Julius	15,000	
Dr W E Massey	49,722	
Sir Tom McKillop	20,000	
H M P Miles	22,145	
Sir Ian Prosser	16,301	
P D Sutherland	30,079	
M H Wilson	60,000	

As at June 28, 2005, 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:

Dr D C Allen	794,950
The Lord Browne of Madingley	5,878,979
I C Conn	492,247
Dr B E Grote	1,427,190(a)
Dr A B Hayward	769,702
J A Manzoni	780,523

(a) In addition to the above, Dr Grote holds 75,200 Stock Appreciation Rights (equivalent to 451,200 ordinary shares).

(b) Performance shares awarded on April 28, 2005 under the BP Executive Directors Incentive Plan. These represent the maximum possible vesting levels. The actual number of shares/ADSs which vest will depend on the extent to which performance conditions have been satisfied over a three year period.

There are no directors or members of senior management who own more than 1% of the ordinary Shares outstanding. At June 28, 2005, all directors and senior management as a group held interests in 10,788,278 ordinary shares or their calculated equivalent and 12,416,830 options for ordinary shares or their calculated equivalent under the BP Group share options schemes.

Additional details regarding the options granted, including exercise price and expiry dates, are found in this item under the heading 'Compensation Share Options.'

Employee Share Plans

	2004	2003	2002
	(options thousands)		
Employee share options granted during the year (a)			
Executive Directors' Incentive Plan	2,783	2,728	2,068
BP Share Option Plan	71,750	78,109	66,771
Savings-related schemes	5,861	23,922	9,719
	80,394	104,759	78,558

(a) The exercise prices for BP options granted during the year were £4.22/$7.73 (weighted average price) for Executive Directors' Incentive Plan (2,783,333 options); £4.38/$8.01 (weighted average price) for 71,750,436 options granted under the BP Share Option Plan; and £3.86/$7.06 (5,860,991 options) for savings-related and similar plans.

BP offers most of its employees the opportunity to acquire a shareholding in the Company through savings-related and/or matching share plan arrangements. Such arrangements are now in place in more than 80 countries. BP also uses long-term performance plans (see Item 18 Financial Statements Note 39 on page F-79) and the granting of share options as elements of remuneration for executive directors and senior employees.

During 2004, share options were granted to the executive directors under the EDIP. For these options, the option exercise price was the market value (as determined in accordance with the plan rules) on the grant date. The options granted to executive directors reflect BP's performance in terms of total shareholder return, 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 as well as the underlying health of the business and the competitive marketplace. Options have not been granted in any year unless the criteria for an award of shares under the share element of the EDIP (see Item 18 Financial Statements Note 39 on page F-79) have been met. Options vest over three years (one-third each after one, two and three years respectively) and have a life of seven years after the grant.

Share options were also granted in 2004 under the BP Share Option Plan to certain categories of employees. Subject to certain vesting requirements, the options are exercisable between the third and 10th 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 plan), employees save on a monthly basis 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.

Under 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 70 other countries.

The Company sponsors a number of savings plans covering most US employees. Under these plans, most employees may contribute up to 100% of their salary subject to certain regulatory limits. Most employees are eligible for a dollar-for-dollar Company-matched contribution for the first 7% of eligible pay contributed on a before-tax or after-tax basis, or a combination of both. The precise arrangement may vary in certain business units. Plan participants may invest contributions in more than 200 investment options, including a fund comprised primarily of BP ADSs. The Company's contributions generally vest over a period of three years (0% for years one and two and 100% after completion of three years). Company contributions to savings plans during the year were $138 million ($130 million).

An Employee Share Ownership Plan (ESOP) was established in 1997 to acquire BP shares to satisfy future requirements of employee share plans. The Company provides funding to the ESOP. Until such time as the Company's own shares held by the ESOP trust vest unconditionally in employees, the amount paid for those shares is deducted in arriving at shareholders' interest (see Item 18 Financial Statements Note 35 on page F-72). Other assets and liabilities of the ESOP are recognized as assets and liabilities of the Company. The ESOP has waived its rights to dividends.

During 2004, the ESOP released 14,156,047 shares (16,892,853 shares) for the matching share plans. The cost of shares released for these plans has been charged in BP's accounts. At December 31, 2004, the ESOP held 2,682,860 shares (7,811,544 shares), which had a market value of $26 million ($63 million).

Pursuant to the various BP Group share option schemes, the following options for Ordinary Shares of the Company were outstanding at June 28, 2005:

Options outstanding	Expiry dates of options	Exercise price per share
(shares)		
478,416,804	2005-2015	$4.22-$10.63

Further details on share options appear in Item 18 Financial Statements Note 38 on page F-75.

ITEM 7 MAJOR SHAREHOLDERS AND RELATED PARTY TRANSACTIONS

MAJOR SHAREHOLDERS

At June 28, 2005, the Company has been notified that JPMorgan Chase Bank, as depositary for American Depositary Shares (ADSs), holds interests through its nominee, Guaranty Nominees Limited, in 7,004,020,650 ordinary shares (33.07% 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 (3.32% of the Company's ordinary share capital). The KIO does not have any different voting rights from the rights of other ordinary shareholders. At the same date, Barclays plc holds interests in 750,956,107 ordinary shares (3.52% of the Company's ordinary share capital) and Legal and General holds interests in 768,172,570 ordinary shares (3.57% of the Company's share capital).

At the date of this report the Company has also been notified of the following interests in preference shares. Co-operative Insurance Society Limited holds interests in 1,475,538 8% 1st preference shares (20.40% of that class) and 1,789,796 9% 2nd preference shares (32.70% of that class). The National Farmers Mutual Insurance Society Ltd holds 945,000 8% 1st preference shares (13.07% of that class) and 987,000 2nd preference shares (18.03% of that class). Prudential plc holds interests in 528,150 8% 1st preference shares (7.30% of that class) and 644,450 9% 2nd preference shares (11.77% of that class). Royal & SunAlliance Insurance plc holds interests in 287,500 8% 1st preference shares (3.97% of that class) and 250,000 2nd preference shares (4.57% of that class). Ruffer Limited Liability Partnership holds interests in 750,000 9% preference shares (13.70% of that class).

RELATED PARTY TRANSACTIONS

The Group had no material transactions with joint ventures and associated undertakings during the period commencing January 1, 2004 to the date of this filing. Transactions between the Group and its significant joint ventures and associated undertakings are summarized in Item 18 Financial Statements Note 42 on page F-82.

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, 2004 to June 28, 2005.

ITEM 8 FINANCIAL INFORMATION

CONSOLIDATED STATEMENTS AND OTHER FINANCIAL INFORMATION

Financial Statements

See Item 18 Financial Statements.

Dividends

The total dividends announced for 2004 were $6,371 million, compared with $5,753 million in 2003 and $5,375 million in 2002. Dividends per share for 2004 were 29.45 cents, compared with 26.00 cents per share in 2003 (an increase of 13%) and 24.00 cents per share in 2002 (an increase of 8.3% over 2002). For information on our policy on distributions to shareholders, refer to Item 5 Operating and Financial Review Liquidity and Capital Resources Dividends and Other Distributions to Shareholders and Gearing on page 101.

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 Atlantic Richfield. 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, Atlantic Richfield Company, 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 Atlantic Richfield. Atlantic Richfield (and in one case two of its affiliates) 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 lawsuit against Atlantic Richfield has been settled or tried to conclusion. The amounts claimed and, if such suits were successful, the costs of implementing the remedies sought in the various cases could be substantial. While it is not possible to predict the outcome of these legal actions, Atlantic Richfield believes that it has valid defenses and it intends to defend such actions vigorously and thus the incurrence of liability by Atlantic Richfield is remote. Consequently, BP believes that the impact of these lawsuits on the Group's results of operations, financial position or liquidity will not be material.

For certain information regarding environmental proceedings see Item 4 Environmental Protection United States Regional Review on page 75.

For certain information regarding the explosion and fire at the Texas City Refinery on March 23, 2005, see Item 4 Refining and Marketing on page 45 and Item 4 Environmental Protection Health, Safety and Environmental Regulation on page 73.

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 (LSE). 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 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 JPMorgan Chase Bank is the depositary (the Depositary) and transfer agent. The Depositary's address is 1 Chase Manhattan Plaza, 40th Floor, New York, NY 10081, USA. Each ADS represents six 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 certificated or book entry form.

The following table sets forth for the periods indicated the highest and lowest middle market quotations for the Ordinary shares of BP p.l.c. for 2000, 2001, 2002, 2003 and 2004. 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.

		Ordinary shares		American Depositary Shares (a)	
		High	Low	High	Low
		(Pence)		(Dollars)	
Year ended December 31,					
2000		671.00	444.50	60.63	43.13
2001		647.00	491.50	54.86	43.23
2002		625.00	392.50	53.88	36.78
2003		454.50	356.50	49.59	34.67
2004		556.50	413.50	62.10	46.65
Year ended December 31,					
2003:	First quarter	429.25	356.50	41.94	34.67
	Second quarter	446.00	395.00	45.34	37.75
	Third quarter	449.50	404.25	43.54	39.25
	Fourth quarter	454.50	404.75	49.59	41.65
2004:	First quarter	457.00	413.50	51.48	46.65
	Second quarter	500.50	455.50	54.99	50.75
	Third quarter	539.00	481.00	59.04	51.95
	Fourth quarter	556.50	500.50	62.10	57.31
2005:	First quarter	576.00	504.00	66.65	56.60
	Second quarter (through June 28)	595.00	523.00	64.94	57.95
Month of					
December 2004		532.00	500.50	61.92	57.93
January 2005		533.00	504.00	60.39	56.60
February 2005		568.00	534.00	66.05	59.95
March 2005		576.00	547.00	66.65	61.00
April 2005		570.00	523.00	64.49	58.75
May 2005		560.50	528.00	62.50	57.95
June 2005 (through June 28)		595.00	558.00	64.94	60.48

(a) An ADS is equivalent to six Ordinary Shares.

Market prices for the 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 June 28, 2005, 1,167,336,775 ADSs (equivalent to 7,004,020,650 ordinary shares or some 33.07% of the total) were outstanding and were held by approximately 160,118 ADR holders. Of these, about 158,241 had registered addresses in the USA at that date. One of the registered holders of ADSs represents some 824,600 underlying holders.

On June 28, 2005 there were approximately 334,287 holders of record of ordinary shares. Of these holders, around 1,399 had registered addresses in the USA and held a total of some 3,455,341 ordinary shares.

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.

On April 24, 2003, the shareholders of BP voted at the AGM to adopt new Articles of Association to consolidate amendments which have been necessary to implement legislative changes since the previous Articles of Association were adopted in 1983.

At the AGM held on April 15, 2004, shareholders approved an amendment to the Articles of Association such that at each AGM held after December 31, 2004, all directors shall retire from office and may offer themselves for re-election. There have been no further amendments to the Articles of Association.

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 1% 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 definition of 'interest' now includes the interests of spouses, children, companies and Trusts. 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 AGM. 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 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.

The directors have the power to declare and pay dividends in any currency provided that a sterling equivalent is announced. It is not the Company's intention to change its current policy of paying dividends in US dollars.

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 £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, JPMorgan Chase Bank, 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 AGM at which it is proposed to put a special or ordinary resolution requires 21 days' notice. An extraordinary resolution put to the AGM 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.

At the AGM held on April 15, 2004, shareholders approved an amendment to the Articles of Association such that at each AGM held after December 31, 2004, all directors shall retire from office and may offer themselves for re-election.

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 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 resolutions, by determination of the directors), and may issue shares which are to be 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 a 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 AGM of shareholders will be held within 15 months after the preceding AGM. All other general meetings of shareholders shall be called Extraordinary General Meetings and all general meetings shall be held 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. Powers exist for action to be taken either before or at the meeting by authorized officers to ensure its orderly conduct and safety of those attending.

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

None.

EXCHANGE CONTROLS AND OTHER LIMITATIONS AFFECTING SECURITY HOLDERS

There are currently no UK foreign exchange controls or restrictions on remittances of dividends on the 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

This section describes the material United States federal income tax and UK taxation consequences of owning ordinary shares or ADSs to a US holder that holds the ordinary shares or ADSs as capital assets for tax purposes. It does not apply, however, to members of special classes of holders subject to special rules and holders that, directly or indirectly, hold 10% or more of the Company's voting stock.

A US holder is any beneficial owner of ordinary shares or ADSs that is for United States federal income tax purposes (i) a citizen or resident of the United States, (ii) a United States domestic corporation, (iii) an estate whose income is subject to United States federal income taxation regardless of its source, or (iv) a trust if a United States court can exercise primary supervision over the trust's administration and one or more United States persons are authorized to control all substantial decisions of the trust.

This section is based on the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed regulations thereunder, published rulings and court decisions, and the taxation laws of the United Kingdom, all as currently in effect, as well as on the income tax convention between the United States and the United Kingdom entered into force in 1980 (the 'Old Treaty') and the income tax convention between the United States and the United Kingdom that entered into force on March 31, 2003 (the 'New Treaty'). These laws are subject to change, possibly on a retroactive basis.

For purposes of the Old Treaty, the New Treaty, and the estate and gift tax Convention (the Estate Tax Convention), and for United States federal income tax and UK taxation purposes, a holder of ADRs evidencing ADSs will be treated as the owner of the Company's ordinary shares represented by those ADRs. Exchanges of ordinary shares for ADRs, and ADRs for ordinary shares, generally will not be subject to United States federal income tax or to UK taxation, other than stamp duty or stamp duty reserve tax, as described below.

This section is further based in part upon the representations of the Depositary and assumes that each obligation in the Deposit Agreement and any related agreement will be performed in accordance with its terms.

Investors should consult their own tax advisor regarding the United States federal, state and local, the UK and other tax consequences of owning and disposing of ordinary shares and ADSs in their particular circumstances, and in particular whether they are eligible for the benefits of the Old Treaty and the New Treaty.

Taxation of Dividends

United Kingdom Taxation

Under current UK taxation law, no withholding tax will be deducted from dividends paid by the Company. A shareholder that is a company resident for tax purposes in the United Kingdom generally will not be taxable on a dividend it receives from the Company. A shareholder who is an individual resident for tax purposes in the United Kingdom is entitled to a tax credit on cash dividends paid on ordinary shares or ADSs of the Company equal to one-ninth of the cash dividend.

Under the Old Treaty, a US holder entitled to its benefits was entitled to a refund from the UK Inland Revenue equal to the amount of the tax credit available to a shareholder resident in the United Kingdom (i.e., one-ninth of the dividend received), but the amount of the dividend plus the amount of the refund was also subject to withholding tax in an amount equal to the amount of the tax credit. Such US holder therefore did not receive any payment from the UK Inland Revenue in respect of a dividend from the Company and had no further UK tax to pay in respect of that dividend. Under the Old Treaty, special rules applied for determining the tax credit available to a corporation that, either alone or together with one or more associated corporations, controlled, directly or indirectly, 10% or more of the Company's voting stock.

Under the New Treaty, a US holder is not entitled to a tax credit from the UK Inland Revenue in respect of dividends in the manner described above. However, dividends received by the US holder from the Company generally are not subject to a withholding tax by the United Kingdom.

Generally, the New Treaty is effective in respect of taxes withheld at source for amounts paid or credited on or after May 1, 2003. Other provisions of the New Treaty, however, took effect for UK tax purposes for individuals on April 6, 2003 (April 1, 2003, for UK companies), and took effect for United States federal income tax purposes on January 1, 2004. The rules of the Old Treaty remained applicable until these effective dates. An eligible US holder could have elected to have the Old Treaty apply in its entirety for a period of twelve months after the applicable effective dates of the New Treaty, in which case it may have been eligible for the tax credit in respect of dividends noted above.

United States Federal Income Taxation

A US holder is subject to United States federal income taxation on the gross amount of any dividend paid by the Company out of its current or accumulated earnings and profits (as determined for United States federal income tax purposes). Dividends paid to a non-corporate US holder in taxable years beginning after December 31, 2002, and before January 1, 2009, that constitute qualified dividend income will be taxable to the holder at a maximum tax rate of 15%, provided that the holder has a holding period in the ordinary shares or ADSs of more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meets other holding period requirements. Dividends paid by the Company with respect to the shares or ADSs will generally be qualified dividend income.

A US holder that was eligible for the benefits of the Old Treaty could include in the gross amount of any dividend paid the UK tax deemed withheld from the dividend payment pursuant to the Old Treaty, as described above in 'United Kingdom Taxation'. Subject to certain limitations, the United Kingdom tax withheld in accordance with the Old Treaty and effectively paid over to the UK Inland Revenue was creditable against the US holder's United States federal income tax liability, provided the US holder was eligible for the benefits of the Old Treaty and appropriately filed Internal Revenue Form 8833. Special rules applied in determining the foreign tax credit limitation with respect to dividends that were subject to the maximum 15% tax rate.

As noted above in 'United Kingdom Taxation', a US holder will not be entitled to a UK tax credit under the New Treaty, but also will not be subject to UK withholding tax. Under the New Treaty, the US holder will include in gross income for United States federal income tax purposes only the amount of the dividend actually received from the Company, and the receipt of a dividend will not entitle the US holder to a foreign tax credit.

For United States federal income tax purposes, a dividend must be included in income when the US holder, in the case of ordinary shares, or the Depositary, in the case of ADSs, actually or constructively receives the dividend, and will not be eligible for the dividends-received deduction generally allowed to United States corporations in respect of dividends received from other United States corporations. Dividends will be income from sources outside the United States, and generally will be 'passive income' or, in the case of certain US holders, 'financial services income', which is treated separately from other types of income for purposes of computing the allowable foreign tax credit.

The amount of the dividend distribution on the ordinary shares or ADSs that is paid in pounds sterling will be the US dollar value of the pounds sterling payments made, determined at the spot pounds sterling/US dollar rate on the date the dividend distribution is includible in income, regardless of whether the payment is in fact converted into US dollars. Generally, any gain or loss resulting from currency exchange fluctuations during the period from the date the pounds sterling dividend payment is includible in income to the date the payment is converted into US dollars will be treated as ordinary income or loss. The gain or loss generally will be income or loss from sources within the United States for foreign tax credit limitation purposes.

Distributions in excess of the Company's earnings and profits, as determined for United States federal income tax purposes, will be treated as a return of capital to the extent of the US holder's basis in the ordinary shares or ADSs and thereafter as capital gain, subject to taxation as described below in 'Taxation of Capital Gains-United States Federal Income Taxation'.

Taxation of Capital Gains

United Kingdom Taxation

A US holder may be liable for both United Kingdom and United States tax in respect of a gain on the disposal of ordinary shares or ADSs if the US holder is (i) a citizen of the United States resident or ordinarily resident in the United Kingdom, (ii) a United States domestic corporation resident in the United Kingdom by reason of its business being managed or controlled in the United Kingdom or (iii) a citizen of the United States or a corporation that carries on a trade or profession or vocation in the United Kingdom through a branch or agency or, in respect of corporations for accounting periods beginning on or after January 1, 2003, through a permanent establishment, and that have used, held, or acquired the ordinary shares or ADSs for the purposes of such trade, profession or vocation of such branch, agency or permanent establishment. However, subject to applicable limitations and provisions of the Old Treaty, such persons may be entitled to a tax credit against their United States federal income tax liability for the amount of United Kingdom capital gains tax or UK corporation tax on chargeable gains (as the case may be) which is paid in respect of such gain.

Under the New Treaty, capital gains on dispositions of ordinary shares or ADSs generally will be subject to tax only in the jurisdiction of residence of the relevant holder as determined under both the laws of the United Kingdom and the United States and as required by the terms of the New Treaty.

Under the New Treaty, individuals who are residents of either the United Kingdom or the United States and who have been residents of the other jurisdiction (the United States or the United Kingdom, as the case may be) at any time during the six years immediately preceding the relevant disposal of ordinary shares or ADSs may be subject to tax with respect to capital gains arising from a disposition of ordinary shares or ADSs of the Company not only in the jurisdiction of which the holder is resident at the time of the disposition, but also in the other jurisdiction.

United States Federal Income Taxation

A US holder that sells or otherwise disposes of ordinary shares or ADSs will recognize a capital gain or loss for United States federal income tax purposes equal to the difference between the US dollar value of the amount realized and the holder's tax basis, determined in US dollars, in the ordinary shares or ADSs. Capital gain of a noncorporate US holder that is recognized on or after May 6, 2003, and before January 1, 2009, is generally taxed at a maximum rate of 15% if the holder's holding period for such ordinary shares or ADSs exceeds one year. The gain or loss will generally be income or loss from sources within the United States for foreign tax credit limitation purposes. The deductibility of capital losses is subject to limitations.

Additional Tax Considerations

UK Inheritance Tax

The Estate Tax Convention applies to inheritance tax. ADSs held by an individual who is domiciled for the purposes of the Estate Tax Convention in the US and is not for the purposes of the Estate Tax Convention a national of the UK will not be subject to UK inheritance tax on the individual's 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 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 payable in the

US to be credited against tax payable in the UK or for tax paid in the UK to be credited against tax payable in the US, 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 ordinary shares, as opposed to ADSs, through the CREST system of paperless share transfers will be subject to stamp duty reserve tax at 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 ordinary shares even if the agreement is made outside the UK between two non-residents. Purchases of ordinary shares outside the CREST system are subject either to stamp duty at a rate of 50 pence per £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 ordinary shares to the Depositary's nominee will give rise to further stamp duty at the rate of £1.50 per £100 (or part) or stamp duty reserve tax at the rate of 1.5% of the value of the ordinary shares at the time of the transfer.

A transfer of the underlying 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 £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 100 F Street NE, Washington, DC 20549. 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 or commodity instruments, indices or prices which are defined in the contract. The Group also trades derivatives in conjunction with risk management activities.

The Group's supply and trading activities in oil, natural gas, power and financial markets are managed within a single integrated function. This has the responsibility for ensuring high and consistent standards of control, making investments in the necessary systems and supporting infrastructure and providing professional management oversight. In market risk management and trading, conventional exchange-traded derivative instruments such as futures and options are used, as well as conventional 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 realized and unrealized gains and losses, are recognized in the period in which they occur.

All derivative activity, whether for risk management or trading, is carried out by specialist teams that have the appropriate skills, experience and supervision. These teams are subject to close financial and management control. The appropriate governance, control framework and reporting processes are in place to oversee these internal control activities. On an ongoing basis, an independent control function monitors compliance with BP's policies that are in line with generally accepted industry practice, reflecting the principles of the Group of Thirty Global Derivatives Study. 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.

Further information about BP's use of derivatives, their characteristics, and the accounting treatment thereof is given in Item 18 Financial Statements Note 1 and Note 28 on pages F-12 and F-48.

The Group's accounting policies under UK GAAP do not satisfy the criteria for hedge accounting under SFAS No. 133 'Accounting for Derivative Instruments and Hedging Activities'. See Item 18 Financial Statements Note 50 on page F-113 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, the capital expenditure and operational requirements, mainly in the UK, the sterling cash flow requirements for UK Corporation Tax and the net euro cash inflows mainly relating to downstream and petrochemicals in Europe. In addition, most of the Group's borrowings are in US dollars or are hedged with respect to the US dollar. At December 31, 2004, the total of foreign currency borrowings not swapped into US dollars amounted to $595 million. The principal elements of this are $297 million of borrowings in euros, $96 million in sterling, $88 million in Canadian dollars and $87 million in Trinidad and Tobago dollars.

The following table provides information about the Group's foreign currency derivative financial instruments. These include foreign currency forward exchange agreements (forwards), cylinder option contracts (cylinders), and purchased call options 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 cross currency swaps such that currency risk is completely eliminated, neither the borrowing nor the derivative are included in the table.

For forwards, the tables present 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 sterling forwards relate mainly to sterling-based capital leases which effectively convert the lease obligation from sterling into dollars and to payments for capital expenditure. The pay euro forwards relate mainly to net cash inflows from operations and the sale of business assets. The receive euro forwards relate mainly to payments for capital expenditure. The Norwegian krone forwards relate mainly 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.

Cylinders consist of purchased call option and written put option contracts. For cylinders and purchased call options, the tables present the notional amounts of the option contracts at December 31, 2004 and the weighted average strike rates. The receive sterling cylinders and purchased call options relate to the Group's expected sterling tax payments and to payments for capital and operational expenditure.

The fair values for the foreign exchange contracts in the table below are based on market prices of comparable instruments (forwards) and pricing models which take into account relevant market data (options). 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							
	2005	2006	2007	2008	2009	Beyond 2009	Total	Fair value asset/ (liability)
					($ million)			
At December 31, 2004								
Forwards								
Receive sterling/pay US dollars								
Contract amount	2,559	136	61	21	9	35	2,821	253
Weighted average contractual exchange rate	1.75							
Receive sterling/pay euro								
Contract amount	24	29	15				68	(2)
Weighted average contractual exchange rate	£ 0.72							
Receive euro/pay US dollars								
Contract amount	237	78	28	11	10	36	400	69
Weighted average contractual exchange rate	1.18							
Pay euro/receive US dollars								
Contract amount	1,829	5					1,834	(5)
Weighted average contractual exchange rate	1.35							
Receive Norwegian krone/ pay US dollars								
Contract amount	232	4					236	22
Weighted average contractual exchange rate (a)	6.66							
Cylinders								
Receive sterling/pay US dollars								
Purchased call								
Contract amount	904						904	32
Weighted average strike price	1.87							
Sold put								
Contract amount	904						904	(3)
Weighted average strike price	1.75							
Purchased call options								
Receive sterling/pay US dollars								
Purchased call								
Contract amount	1,467						1,467	18
Weighted average strike price	1.97							
Receive euro/pay US dollars								
Purchased call								
Contract Amount	1,182						1,182	9
Weighted average strike price	1.44							

(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.

	Notional amount by expected maturity date							
	2004	2005	2006	2007	2008	Beyond 2008	Total	Fair value asset/ (liability)
	($ million)							
At December 31, 2003								
Forwards								
Receive sterling/pay US dollars								
Contract amount	2,177	95	36	15	11	45	2,379	307
Weighted average contractual exchange rate	1.57							
Receive sterling/pay euro								
Contract amount	340	26	27	14			407	(4)
Weighted average contractual exchange rate	£ 0.70							
Receive euro/pay US dollars								
Contract amount	255	100	16	12	11	45	439	74
Weighted average contractual exchange rate	1.08							
Pay euro/receive US dollars								
Contract amount	206	19	5				230	(16)
Weighted average contractual exchange rate	1.18							
Receive Norwegian krone/pay US dollars								
Contract amount	170	21	1				192	16
Weighted average contractual exchange rate (a)	7.31							
Cylinders								
Receive sterling/pay US dollars								
Purchased call								
Contract amount	1,363						1,363	12
Weighted average strike price	1.80							
Sold put								
Contract amount	1,363						1,363	(3)
Weighted average strike price	1.66							
Purchased call options								
Receive sterling/pay US dollars								
Purchased call								
Contract amount	779						779	14
Weighted average strike price	1.80							

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. The proportion of floating rate debt at December 31, 2004 was 96% of total finance debt outstanding.

The following table shows, by major currency, the Group's finance debt at December 31, 2004 and 2003 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	Total
	(%)	(years)	($ million)	(%)	($ million)	($ million)
At December 31, 2004						
US dollar	7	11	707	3	21,789	22,496
Sterling				5	96	96
Other currencies	9	15	167	4	332	499
Total loans			874		22,217	23,091
At December 31, 2003						
US dollar	8	14	578	2	20,991	21,569
Sterling				4	107	107
Other currencies	9	15	141	3	508	649
Total loans			719		21,606	22,325

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, 2004. 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, 2005, the Group's 2005 earnings before taxes would decrease by approximately $215 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, 2004 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 certain exposures in respect of its equity share of production and certain of its refinery and marketing activities. To this end, BP's supply and trading function uses the full range of oil price-related 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. Thus the value-at-risk calculation for oil price exposure includes derivative 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)	
2004				
Oil price contracts	11	1	6	10
2003				
Oil price contracts	9	5	7	7
2002				
Oil price contracts	13	11	12	11

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 certain specific sales and purchases contracts from fixed prices to floating prices. Swaps are also used to hedge exposure to price differentials between locations.

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 fixed price and the year-end forward price related to the settlement month for swaps.

At December 31, 2004, in addition to the swaps contracts shown in the table there were options contracts with aggregate notional amounts of $130 million (December 31, 2003 $174 million and December 31, 2002 $11 million) and terms of up to one year.

			Fair value		Weighted average price	
	Quantity	**Contract amount**	**Asset**	**Liability**	**Receive**	**Pay**
	(btu trillion)(a)	**($ million)**	**($ million)**		**($ per mmbtu)(b)**	
At December 31, 2004						
Maturing in 2005						
Swaps						
Receive variable/pay fixed	20	113	5	(9)	5.67	5.90
Receive fixed/pay variable	19	115	17	(1)	6.07	5.24
Receive and pay variable	732	4,304	25	(16)	5.88	5.87
Maturing in 2006						
Swaps						
Receive variable/pay fixed		2		(1)	5.02	6.23
Receive fixed/pay variable	9	50	6	(1)	5.85	5.19
Receive and pay variable	142	871	7	(8)	6.12	6.13
Maturing in 2007						
Swaps						
Receive variable/pay fixed		2			5.04	5.84
Receive fixed/pay variable	2	10	3		5.85	3.99
Receive and pay variable	71	390	7	(6)	5.50	5.49
Maturing in 2008						
Swaps						
Receive variable/pay fixed						
Receive fixed/pay variable	1	7	2		5.54	4.05
Receive and pay variable	52	269	6	(6)	5.21	5.21
Maturing in 2009						
Swaps						
Receive variable/pay fixed						
Receive fixed/pay variable						
Receive and pay variable	49	241	7	(6)	4.94	4.92
Maturing beyond 2009						
Swaps						
Receive variable/pay fixed	1	5			4.85	4.71
Received fixed/pay variable						
Receive and pay variable	46	221	6	(5)	4.78	4.74

	Quantity	Contract amount	Fair value		Weighted average price	
			Asset	Liability	Receive	Pay
	(btu trillion)(a)	($ million)	($ million)		($ per mmbtu)(b)	
At December 31, 2003						
Maturing in 2004						
Swaps						
Receive variable/pay fixed	30	152	29	(2)	4.61	5.07
Receive fixed/pay variable	26	128		(18)	4.84	4.74
Receive and pay variable	758	3,991	51	(47)	5.27	5.27
Maturing in 2005						
Swaps						
Receive variable/pay fixed	5	22	3		4.06	4.48
Receive fixed/pay variable	8	36		(5)	4.56	3.97
Receive and pay variable	212	1,035	23	(22)	4.88	4.89
Maturing in 2006						
Swaps						
Receive variable/pay fixed	2	8	2		3.94	4.72
Receive fixed/pay variable		1			4.72	4.32
Receive and pay variable	88	404	5	(11)	4.62	4.56
Maturing in 2007						
Swaps						
Receive variable/pay fixed	2	8	1		3.99	4.63
Receive fixed/pay variable		1			4.63	4.36
Receive and pay variable	64	279	3	(8)	4.44	4.36
Maturing in 2008						
Swaps						
Receive variable/pay fixed	1	6	1		4.05	4.58
Receive fixed/pay variable						
Receive and pay variable	49	214	2	(6)	4.40	4.31
Maturing beyond 2008						
Swaps						
Receive variable/pay fixed						
Received fixed/pay variable	1	5			4.58	4.85
Receive and pay variable	88	385	3	(7)	4.41	4.36

(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, commodity derivatives and physical instruments. 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 function undertakes trading in the full range of conventional derivative financial and commodity instruments and physical cargoes available in the energy markets. The Group also uses financial and commodity derivatives in its trading activities. These activities are monitored and are subject to maximum value-at-risk limits authorized by the board.

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, 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 approximately 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 models take account of derivative financial instruments such as interest rate forward and futures contracts and swap agreements; foreign exchange forward and futures contracts and swap agreements; and oil, natural gas and power price futures and swap agreements. Financial assets and liabilities and physical crude oil and refined products that are treated as trading positions are also included in these calculations. For options, a linear approximation is included in the value-at-risk models. The value-at-risk calculation for oil, natural gas and power 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)	
2004				
Interest rate trading	1			
Foreign exchange trading	4	1	1	1
Oil price trading	55	18	29	45
Natural gas price trading	23	6	13	10
Power price trading	10	1	4	4
2003				
Interest rate trading	1			
Foreign exchange trading	4		2	1
Oil price trading	34	17	26	27
Natural gas price trading	29	4	16	18
Power price trading	13		4	6
2002				
Interest rate trading				
Foreign exchange trading	2		1	
Oil price trading	34	14	23	19
Natural gas price trading	18	1	6	9
Power price trading	9	1	4	3

The following tables show the changes during the year in the net fair value of instruments held for trading purposes for the years 2004 and 2003.

	Fair value interest rate contracts	Fair value exchange rate contracts	Fair value oil price contracts	Fair value natural gas price contracts	Fair value power price contracts
			($ million)		
Fair value of contracts at January 1, 2004		(24)	(81)	147	34
Contracts realized or settled in the year		9	84	321	(30)
Fair value of new contracts when entered into during the year			(25)	61	22
Other changes in fair values		(39)	5	(302)	150
Fair value of contracts at December 31, 2004		(54)	(17)	227	176
Fair value of contracts at January 1, 2003		12	22	157	19
Contracts realized or settled in the year		(12)	(29)	185	16
Fair value of new contracts when entered into during the year			(43)	(62)	36
Other changes in fair values		(24)	(31)	(133)	(37)
Fair value of contracts at December 31, 2003		(24)	(81)	147	34

The following tables show the net fair value of contracts held for trading purposes at December 31, 2004 and 2003 analyzed by maturity period and by methodology of fair value estimation.

	Fair value of contracts at December 31, 2004				
	Maturity less than 1 year	Maturity 1-3 years	Maturity 4-5 years	Maturity over 5 years	Total fair value
			($ million)		
Prices actively quoted	340	(47)	48		341
Prices provided by other external sources	(35)	(10)	10	12	(23)
Prices based on models and other valuation methods	14				14
	319	(57)	58	12	332

	Fair value of contracts at December 31, 2003				
	Maturity less than 1 year	Maturity 1-3 years	Maturity 4-5 years	Maturity over 5 years	Total fair value
			($ million)		
Prices actively quoted	93	53	4		150
Prices provided by other external sources	(81)	(5)		(5)	(91)
Prices based on models and other valuation methods	9	8			17
	21	56	4	(5)	76

	Fair value of contracts at December 31, 2003

ITEM 12 DESCRIPTION OF SECURITIES OTHER THAN EQUITY SECURITIES

Not applicable

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.

ITEM 15 CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

The Company maintains 'disclosure controls and procedures' as such term is defined in Exchange Act Rule 13a-15(e), that are designed to ensure that information required to be disclosed in reports the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including the Company's group chief executive and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, our management, including the group chief executive and chief financial officer, recognize that any controls and procedures, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. Further, in the design and evaluation of our disclosure controls and procedures our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures. Also, we have investments in certain unconsolidated entities. As we do not control these entities, our disclosure controls and procedures with respect to such entities are necessarily substantially more limited than those we maintain with respect to our consolidated subsidiaries. Because of the inherent limitations in a cost-effective control system, mis-statements due to error or fraud may occur and not be detected. The Company's disclosure controls and procedures have been designed to meet, and management believe that they meet, reasonable assurance standards.

During 2005, a review was undertaken into the accounting treatment under US GAAP for OTC forward contracts in oil, gas, NGLs and power in the context of the review undertaken for final transition to IFRS. As a result of this review the Group reassessed its recognition of revenues associated with these contracts under US GAAP and determined that these contracts should be reported net. (See Item 18 Financial Statements Note 50 on page F-103.) Under the provisions of APB 20 the Company's management concluded that the change represented the correction of an accounting error and as a result revenues and cost of sales for US GAAP have been restated. Because under UK GAAP these transactions were reported gross, a difference in accounting treatment is now disclosed in Item 18 Financial Statements Note 50 on page F-103. In addition, in connection with the preparation of this Form 20-F/A, the Group identified additional transactions which should also have been presented net under US GAAP.

In light of this subsequent restatement, the Company's management, including the group chief executive and the chief financial officer, re-evaluated the Company's disclosure controls and procedures as in effect at the end of 2004. Although the restatement for US GAAP purposes did not impact the Group's profit for the year as adjusted to accord with US GAAP, profit per ordinary share, cash flow or financial position, the group chief executive and the chief financial officer have determined, due to the change in the US GAAP accounting treatment for OTC forward contracts, that the Company's disclosure controls and procedures at the end of the period were not effective to provide reasonable assurance that information required to be disclosed in the Company's reports filed or submitted under the Exchange Act was recorded, processed, summarized and reported within the time period specified in the rules and forms of the SEC.

Apart from the failure to account for OTC forward contracts on a net basis under US GAAP, the Company's management has not identified any other deficiencies that would have led the Company's management to conclude that the Group's disclosure controls and procedures were ineffective for the period covered by this annual report. The Company is not currently required to report on management's assessment of the effectiveness of the Group's internal controls over financial reporting and the Company has not undertaken the kind of review of such controls that would be required in order to make such a report.

Following the review of the accounting treatment for OTC forward contracts under US GAAP, the Group has improved its disclosure controls and procedures by changing its US GAAP accounting policy for OTC forward contracts to conform to US GAAP, training the accounting staff regarding the policy change, implementing changes in its internal reporting systems to process and report sale and purchase contracts in accordance with Group US GAAP accounting policy for such transactions and increasing management oversight of compliance therewith.

Changes in Internal Controls

There were no changes in the Company's internal controls over financial reporting that occurred during the period covered by this Form 20-F that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

ITEM 16A AUDIT COMMITTEE FINANCIAL EXPERT

The Board determined that during 2004 no one member of the audit committee had all the attributes of an audit committee financial expert as defined for purposes of disclosure Item 16A of Form 20-F. The Company did not have an audit committee financial expert because the board considered that the membership of the audit committee as a whole had sufficient recent and relevant financial experience to discharge its functions.

Douglas Flint joined the board as a non-executive director on January 1, 2005 and joined the audit committee on March 16, 2005. He is group finance director of HSBC Holdings p.l.c., and a former member of the Accounting Standards Board and the Standards Advisory Council of the International Accounting Standards Board. The Board determined that with effect from March 16, 2005 Mr Flint may be regarded as an audit committee financial expert as defined for purposes of disclosure Item 16A of Form 20-F.

ITEM 16B CODE OF ETHICS

The Company has adopted a Code of Ethics for its group chief executive, deputy group chief executive, chief financial officer, the general auditor, group chief accounting officer and group controller as required by the provisions of Section 406 of the Sarbanes-Oxley Act of 2002 and the rules issued by the SEC. There have been no amendments to, or waivers from, the code of ethics relating to any of those officers. The code of ethics has been filed as an exhibit to this report.

In June 2005, BP published a Code of Conduct which is applicable to all employees.

ITEM 16C PRINCIPAL ACCOUNTANT FEES AND SERVICES

The Audit Committee has established policies and procedures for the engagement of the independent registered public accounting firm, Ernst & Young LLP, to render audit and certain assurance and tax services. The policies provide for pre-approval by the audit committee of specifically defined audit, audit-related, tax and other services that are not prohibited by regulatory or other professional requirements. Ernst & Young is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. 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.

Under the policy, pre-approval is given for specific services within the following categories; advice on accounting, auditing and financial reporting matters; internal accounting and risk management control reviews (excluding any services relating to information systems design and implementation); non-statutory audit; project assurance and advice on business and accounting process improvement (excluding any services relating to information systems design and implementation relating to BP's financial statements or accounting records); due diligence in connection with acquisitions, disposals and joint ventures; income tax and indirect tax compliance and advisory services; and employee tax services (excluding tax services that could impair independence). Additionally, any proposed service not included in the pre-approved services, must be approved in advance prior to commencement of the engagement. The audit committee has delegated to the Chair of the Audit Committee authority to approve permitted services provided that the Chair reports any decisions to the committee at its next scheduled meeting.

	Years ended December 31,		
	2004	**2003**	**2002**
		($ million)	
Audit fees			
Group audit	27	18	15
Audit-related regulatory reporting	7	5	4
Statutory audit of subsidiaries	16	13	10
	50	36	29
Audit-related fees			
Acquisition and disposal due diligence	7	9	13
Pension scheme audits	1	1	1
Other further assurance services	9	9	8
	17	19	22
Tax fees			
Compliance services	13	17	23
Advisory services	1	2	4
	14	19	27
Other fees			1
Total non-audit fees	31	38	50

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 keeps under review the scope and results of audit work, its cost-effectiveness and the independence and objectivity of the auditors. It requires the auditors to rotate their lead audit partner every five years.

Other further assurance services within Audit-related fees include $3 million (2003 $2 million and 2002 $4 million) in respect of advice on accounting, auditing and financial reporting matters; $1 million (2003 $1 million and 2002 $3 million) in respect of internal accounting and risk management control reviews; $3 million (2003 $2 million and 2002 nil) in respect of non-statutory audits and $2 million (2003 $3 million and 2002 $1 million) in respect of project assurance and advice on business and accounting process improvement.

The tax compliance services relate to income tax and indirect tax compliance and employee tax services.

Other fees in 2002 relate to a working capital review.

Fees paid to major firms of accountants other than Ernst & Young for other services amount to $82 million (2003 $44 million and 2002 $33 million).

ITEM 16D EXEMPTIONS FROM THE LISTING STANDARDS FOR AUDIT COMMITTEES

Not applicable.

ITEM 16E PURCHASES OF EQUITY SECURITIES BY THE ISSUER AND AFFILIATED PURCHASERS

The following table provides details of ordinary shares repurchased.

	Total number of shares purchased (a)	Average price paid per share	Total number of shares purchased as part of publicly announced programmes	Maximum number of shares that may yet be purchased under the programme (b)
		($)		
2004				
January				
February	62,884,938	7.93	62,884,938	
March	91,850,000	8.17	91,850,000	
April	36,996,257	8.79	36,996,257	
May	116,371,153	8.87	116,371,153	
June	71,550,915	8.98	71,550,915	
July	95,143,683	9.18	95,143,683	
August	97,182,890	9.29	97,182,890	
September	49,173,524	9.64	49,173,524	
October	70,840,000	9.85	70,840,000	
November	79,546,000	9.97	79,546,000	
December	55,731,000	10.04	55,731,000	
2005				
January	57,900,000	9.71	57,900,000	
February (c)	69,500,000	10.41	69,500,000	
March (d)	65,725,000	10.86	65,725,000	
April (d)	62,656,000	10.38	62,656,000	
May (d)	63,627,000	10.13	63,627,000	
June (through June 28 (d)	66,985,000	10.52	66,985,000	

(a) All share purchases were open market transactions.

(b) At the AGM on April 14, 2005, authorization was given to repurchase up to 2.1 billion ordinary shares in the period to the next AGM or July 13, 2006, the latest date by which an AGM must be held. This authorization is renewed annually at the AGM.

(c) Includes 18,900,000 shares repurchased for cancellation and 50,600,000 shares held in treasury.

(d) Held in treasury.

The following table provides details of share purchases made by ESOP Trusts.

	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced programmes (a)	Maximum number of shares that may yet be purchased under the programme (a)
		($)		
2004				
January	107,819	8.34		
February	1,854,878	7.65		
March	5,920	7.60		
April				
May	9,864	8.20		
June	5,000,000	8.85		
July	9,654,519	9.02		
August	203	8.91		
September				
October	5,498	9.71		
November	8,581	8.83		
December	205	9.50		
2005				
January	143,789	9.79		
February	7,128,864	10.47		
March	6,271,709	10.39		
April	1,219	9.64		
May				
June				

(a) No shares were repurchased pursuant to a publicly announced plan. Transactions represent the purchase of ordinary shares by ESOP Trusts to satisfy future requirements of employee share schemes.

PART III

ITEM 17 FINANCIAL STATEMENTS

Not applicable.

ITEM 18 FINANCIAL STATEMENTS

The following financial statements, together with the reports of the Independent Registered Public Accounting Firm thereon, are filed as part of this annual report:

	Page
Report of Independent Registered Public Accounting Firm	F-1
Consent of Independent Registered Public Accounting Firm	F-2
Consolidated Statement of Income for the Years Ended December 31, 2004, 2003, and 2002	F-3
Consolidated Balance Sheet at December 31, 2004 and 2003	F-4
Consolidated Statement of Cash Flows for the Years Ended December 31, 2004, 2003, and 2002	F-5
Statement of Total Recognized Gains and Losses for the Years Ended December 31, 2004, 2003, and 2002	F-6
Statement of Changes in BP Shareholders' Interest for the Years Ended December 31, 2004, 2003, and 2002	F-7
Notes to Financial Statements	F-10
The following supplementary information is filed as part of this annual report:	
Supplementary Oil and Gas Information (Unaudited)	S-1
Schedule for the Years Ended December 31, 2004, 2003, and 2002 Schedule II Valuation and Qualifying Accounts	S-26

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
Exhibit 11.	Code of Ethics*
Exhibit 12.	Rule 13a - 14(a) Certifications
Exhibit 13.	Rule 13a - 14(b) Certifications**

* Incorporated by reference to the Company's Annual Report on Form 20-F for the year ended December 31, 2003.

** Furnished only.

Previously filed on June 30, 2005 as an exhibit to the Company's Annual Report on Form 20-F for the year ended December 31, 2004.

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.

BP p.l.c. AND SUBSIDIARIES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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, 2004 and 2003, 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, 2004. 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 United Kingdom auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

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, 2004 and 2003, and the consolidated results of its operations and its consolidated cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United Kingdom which differ in certain respects from those generally accepted in the United States of America (see Note 50 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.

As discussed in Note 46 of Notes to Financial Statements, in the year ended December 31, 2004 the Company changed its method of accounting for retirement benefits and employee share ownership plan trusts.

As discussed in Note 50(s) of Notes to the Financial Statements, the turnover and cost of sales, reported under accounting principles generally accepted in the United States of America, have been restated.

/s/ ERNST & YOUNG LLP

Ernst & Young LLP

London, England
February 7, 2005
Except for Note 50(s),
as to which the date is
June 13, 2006

BP p.l.c. AND SUBSIDIARIES

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference of our report dated February 7, 2005, except for Note 50(s), as to which the date is June 13, 2006 with respect to the consolidated financial statements and schedule of BP p.l.c. included in Amendment No. 1 to the Annual Report (Form 20-F) for the year ended December 31, 2004 in the following Registration Statements:

Registration Statements (Form F-3 Nos. 333-9790, 333-65996 and 333-110203) of BP p.l.c.;

Registration Statement (Form F-3 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 (Form S-8 Nos. 333-21868, 333-9020, 333-9798, 333-79399, 333-34968, 333-67206, 333-74414, 333-102583, 333-103923, 333-103924, 333-119934, 333-123482, 333-123483, 333-132619, 333-131583, 333-131584 and 333-132619) of BP p.l.c.

/s/ ERNST & YOUNG LLP

London, England
June 13, 2006

Ernst & Young LLP

BP p.l.c. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF INCOME

	Note	2004	2003	2002
		Years ended December 31,		
		($ million, except per share amounts)		
Turnover		294,849	236,045	180,186
Less: Joint ventures		9,790	3,474	1,465
Group turnover	2	285,059	232,571	178,721
Cost of sales		247,110	201,335	154,615
Production taxes	3	2,149	1,723	1,274
Gross profit		35,800	29,513	22,832
Distribution and administration expenses	4	14,988	14,072	12,632
Exploration expense		637	542	644
		20,175	14,899	9,556
Other income	5	675	786	641
Group operating profit		20,850	15,685	10,197
Share of profits of joint ventures		2,943	924	347
Share of profits of associated undertakings		634	514	617
Total operating profit		24,427	17,123	11,161
Profit (loss) on sale of businesses or termination of operations	7	(695)	(28)	(33)
Profit (loss) on sale of fixed assets	7	1,510	859	1,201
Profit before interest and tax		25,242	17,954	12,329
Interest expense	8	642	644	1,067
Other finance expense	9	357	547	73
Profit before taxation		24,243	16,763	11,189
Taxation	14	8,282	6,111	4,317
Profit after taxation		15,961	10,652	6,872
Minority shareholders' interest		230	170	77
Profit for the year*		15,731	10,482	6,795
Dividend requirements on preference shares*		2	2	2
Profit for the year applicable to ordinary shares*		15,729	10,480	6,793
Profit per ordinary share cents				
Basic	17	72.08	47.27	30.33
Diluted	17	70.79	46.83	30.19
Dividends per ordinary share cents	16	29.45	26.00	24.00

	Years ended December 31,		
Average number outstanding of 25 cents ordinary shares (in thousands)	21,820,535	22,170,741	22,397,126

* 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 50.

The Notes to Financial Statements are an integral part of this Statement.

BP p.l.c. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

	Note	December 31, 2004		December 31, 2003	
		($ million)			
Fixed assets					
Intangible assets	21		12,076		13,642
Tangible assets	22		96,748		91,911
Investments					
Joint ventures					
Gross assets		18,244		15,265	
Gross liabilities		6,316		5,111	
Minority shareholders' interest		542		365	
	23	11,386		9,789	
Loans	23	1,065		1,220	
Net investment			12,451		11,009
Associated undertakings	23		5,488		4,870
Other	23		467		1,579
			18,406		17,458
Total fixed assets			127,230		123,011
Current assets					
Inventories	24	15,698		11,617	
Trade receivables	25	31,223		23,487	
Other receivables falling due					
Within one year	25	13,172		7,897	
After more than one year	25	2,301		2,518	
Investments	26	328		185	
Cash at bank and in hand		1,156		1,947	
		63,878		47,651	
Current liabilities falling due within one year					
Finance debt	30	10,184		9,456	
Trade payables	31	28,340		20,858	
Other accounts payable and accrued liabilities	31	26,001		20,270	
		64,525		50,584	
Net current assets (liabilities)			(647)		(2,933)
Total assets less current liabilities			126,583		120,078
Noncurrent liabilities					
Finance debt	30	12,907		12,869	
Accounts payable and accrued liabilities	31	4,505		6,030	
Provisions for liabilities and charges					
Deferred taxation	14	15,050		14,371	
Other	32	9,608		8,599	
			42,070		41,869

		December 31,	
Net assets excluding pension and other postretirement benefit balances		84,513	78,209
Defined benefit pension plan surpluses	33	1,475	1,146
Defined benefit pension plan deficits	33	(5,863)	(5,005)
Other postretirement benefit plan deficit	34	(2,126)	(2,630)
Net assets		77,999	71,720
Minority shareholders' interest equity		1,343	1,125
BP shareholders' interest*		76,656	70,595
Represented by:			
Capital shares			
Preference		21	21
Ordinary		5,382	5,531
Paid in surplus	35	6,366	4,480
Merger reserve	35	27,162	27,077
Other reserves	35	44	129
Shares held by ESOP trusts	35	(82)	(96)
Retained earnings	35/36	37,763	33,453
		76,656	70,595

* 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 50.

The Notes to Financial Statements are an integral part of this Balance Sheet.

BP p.l.c. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note	Years ended December 31, 2004	2003	2002
			($ million)	
Net cash inflow from operating activities	37	28,554	21,698	19,342
Dividends from joint ventures		1,908	131	198
Dividends from associated undertakings		291	417	368
Servicing of finance and returns on investments				
Interest received		332	175	231
Interest paid		(694)	(1,006)	(1,204)
Dividends received		53	140	102
Dividends paid to minority shareholders		(33)	(20)	(40)
Net cash outflow from servicing of finance and returns on investments		(342)	(711)	(911)
Taxation				
UK corporation tax		(1,447)	(1,185)	(979)
Overseas tax		(4,931)	(3,619)	(2,115)
Tax paid		(6,378)	(4,804)	(3,094)
Capital expenditure and financial investment				
Payments for tangible and intangible fixed assets		(13,035)	(12,368)	(12,049)
Payments for fixed assets investments			(9)	(49)
Proceeds from the sale of fixed assets	20	4,323	6,253	2,470
Net cash outflow for capital expenditure and financial investment		(8,712)	(6,124)	(9,628)
Acquisitions and disposals				
Acquisitions, net of cash acquired		(1,503)	(211)	(4,324)
Proceeds from the sale of businesses	20	725	179	1,974
Acquisition of investment in TNK-BP joint venture		(1,250)	(2,351)	
Net investment in other joint ventures		(272)	(178)	(354)
Investments in associated undertakings		(942)	(987)	(971)
Proceeds from sale of investment in Ruhrgas	20			2,338
Net cash outflow for acquisitions and disposals		(3,242)	(3,548)	(1,337)
Equity dividends paid		(6,041)	(5,654)	(5,264)
Net cash inflow (outflow)		6,038	1,405	(326)
Financing	37	6,777	1,129	(163)
Management of liquid resources	37	132	(41)	(220)

		Years ended December 31,		
Increase (decrease) in cash	37	(871)	317	57
		6,038	1,405	(326)

For a cash flow statement and a statement of comprehensive income prepared on the basis of US GAAP see Note 50 US generally accepted accounting principles.

The Notes to Financial Statements are an integral part of this Statement.

BP p.l.c. AND SUBSIDIARIES

STATEMENT OF TOTAL RECOGNIZED GAINS AND LOSSES

	Years ended December 31,		
	2004	**2003**	**2002**
		($ million)	
Profit for the year	15,731	10,482	6,795
Currency translation differences	2,351	3,681	3,426
Actuarial gain (loss) relating to pensions and other postretirement benefits	107	76	(7,829)
Unrealized gain on acquisition of further investment in equity-accounted investments	94		
Tax on currency translation differences	(208)	(37)	(142)
Tax on actuarial gain (loss) relating to pensions and other postretirement benefits	96	(16)	2,459
Total recognized gains and losses relating to the year	18,171	14,186	4,709
Prior year adjustment change in accounting policy	(132)		
Total recognized gains and losses since last annual accounts	18,039		

The Notes to Financial Statements are an integral part of this Statement.

BP p.l.c. AND SUBSIDIARIES

STATEMENT OF CHANGES IN BP SHAREHOLDERS' INTEREST

The Company's authorized ordinary share capital at December 31, 2004, 2003 and 2002 was 36 billion shares of 25 cents each, amounting to $9 billion. In addition the Company has authorized preference share capital of 12,750,000 shares of £1 each ($21 million). Details of movements in share capital are shown in Note 35.

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 £1 each at December 31, 2004, 2003 and 2002	7,250,000	7,232,838	12
9% cumulative second preference shares of £1 each at December 31, 2004, 2003 and 2002	5,500,000	5,473,414	9
Equity ordinary shares of 25 cents each			
Authorized			
December 31, 2004, 2003 and 2002	36,000,000,000		

	Years ended December 31,					
	2004		**2003**		**2002**	
Issued	**Shares of 25 cents each**	**Amount**	**Shares of 25 cents each**	**Amount**	**Shares of 25 cents each**	**Amount**
	(thousands)	**($ million)**	**(thousands)**	**($ million)**	**(thousands)**	**($ million)**
January 1	22,122,610	5,531	22,378,651	5,595	22,432,077	5,608
Employee share schemes (a)	62,224	16	32,889	8	33,821	9
Atlantic Richfield (b)	29,288	7	9,786	2	12,894	3
Issue of ordinary share capital for TNK-BP (c)	139,096	35				
Repurchase of ordinary share capital (d)	(827,240)	(207)	(298,716)	(74)	(100,141)	(25)
December 31	21,525,978	5,382	22,122,610	5,531	22,378,651	5,595
Paid in surplus						
January 1		4,480		4,243		4,014
Premium on shares issued:						
Employee share schemes (a)		311		127		129
Atlantic Richfield (b)		153		36		54
Issue of ordinary share capital for TNK-BP (c)		1,215				
Repurchase of ordinary share capital (d)		207		74		25

	Years ended December 31,		
Qualifying Employee Share Ownership Trust (e)			21
December 31	6,366	4,480	4,243

The Notes to Financial Statements are an integral part of this Statement.

	Years ended December 31,		
	2004	2003	2002
	($ million)		
Merger reserve			
January 1	27,077	27,033	26,983
Atlantic Richfield (b)	85	44	50
December 31	27,162	27,077	27,033
Other reserves			
January 1	129	173	223
Atlantic Richfield (b)	(85)	(44)	(50)
December 31	44	129	173
Shares held by ESOP trusts			
January 1	(96)	(159)	
Prior year adjustment change in accounting policy			(266)
As restated	(96)	(159)	(266)
Currency translation differences	(7)	(8)	(19)
Purchase of shares by ESOP trusts	(147)	(63)	(18)
Release of shares by ESOP trusts	168	134	144
December 31	(82)	(96)	(159)
Retained earnings			
January 1	33,453	26,928	28,312
Prior year adjustment change in accounting policy			116
As restated	33,453	26,928	28,428
Currency translation differences (net of tax)	2,143	3,644	3,284
Repurchase of ordinary share capital	(7,548)	(1,999)	(750)
Actuarial gain (loss) (net of tax)	203	60	(5,370)
Unrealized gain on acquisition of further investment in equity-accounted investments	94		
Charge for long-term performance plans and employee share schemes	226	225	81
Release of shares by ESOP trusts	(168)	(134)	(144)
Qualifying Employee Share Ownership Trust (e)			(21)
Profit for the year	15,731	10,482	6,795
Dividends (f)			
Preference (non-equity)	(2)	(2)	(2)
Ordinary (equity)	(6,369)	(5,751)	(5,373)
December 31	37,763	33,453	26,928

(a) Employee share schemes. During the year 62,224,092 ordinary shares were issued under the BP, Amoco and Burmah Castrol employee share schemes.

(b)

Atlantic Richfield. 29,288,178 ordinary shares were issued in respect of Atlantic Richfield employee share option schemes.

(c) Issue of ordinary share capital for TNK-BP. The Company issued 139,095,888 ordinary shares as the first tranche of deferred consideration for the acquisition of the investment in TNK-BP.

(d) Repurchase of ordinary share capital. The Company purchased for cancellation 827,240,360 ordinary shares for a total consideration of $7,548 million.

(e) See Note 38 Employee share plans.

(f) See Note 16 Dividends per ordinary share.

(g) See Note 36 Retained earnings.

(h) 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 £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.

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS

Note 1 Accounting policies

Accounting standards

These accounts are prepared in accordance with applicable UK accounting standards.

In preparing the financial statements for the current year, the Group has adopted Financial Reporting Standard No. 17 'Retirement Benefits' (FRS 17) and Urgent Issues Task Force Abstract No. 38 'Accounting for Employee Share Ownership Plan (ESOP) Trusts' (Abstract No. 38). The adoption of FRS 17 and Abstract No. 38 has resulted in changes in accounting policy for pensions and other postretirement benefits and the accounting of ESOP trusts.

In addition to the requirements of accounting standards, the accounting for exploration and production activities is governed by the Statement of Recommended Practice ('SORP') 'Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities' issued by the UK Oil Industry Accounting Committee on June 7, 2001. These accounts have been prepared in accordance with the provisions of the SORP.

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, 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, interest expense, taxation, gross assets, gross liabilities and minority shareholders' interest 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 on a straight-line basis over its estimated useful economic life, which is usually 10 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.

Accounting convention

The accounts are prepared under the historical cost convention, except as explained under inventory valuation.

Inventory valuation

Inventories, other than inventory held for trading purposes, 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 valued at cost to the Group mainly using the average method or net realizable value, whichever is the lower.

Inventory held for trading purposes is marked-to-market and any gains or losses are recognized in the income statement rather than the statement of total recognized gains and losses. The directors consider that the nature of the Group's trading activity is such that, in order for the accounts to show a true and fair view of the state of affairs of the Group and the results for the year, it is necessary to depart from the requirements of Schedule 4 to the Companies Act 1985. Had the treatment in Schedule 4 been followed, the profit and loss account reserve would have been reduced by $100 million (2003 $150 million and 2002 $209 million) and a revaluation reserve established and increased accordingly.

Revenue recognition

Revenues associated with the sale of oil, natural gas, LNG, petroleum and chemical products and all other items are recognized when the title passes to the customer. Supply buy/sell arrangements with common counterparties are reported net, as are physical exchanges. Oil, natural gas, NGL and power over-the-counter forward sales contracts where the Group acts as principal rather than agent are reported gross and included in turnover. The Group was deemed to be the principal in the over-the-counter forward sales transactions because: (i) the Group was the primary obligator in the arrangement; (ii) the Group had discretion to set the selling price with the customer; (iii) the Group had discretion to select the supplier; (iv) the Group took title to the commodity, albeit often for a short period of time; and (v) the Group was invoiced for the full amount of the transaction and had this liability to a third party, although master netting agreements mitigated the credit risk. 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 currency transactions

Foreign currency transactions by Group companies are booked in the functional currency at the exchange rate ruling on the date of transaction, or at the forward rate if hedged by a forward exchange contract. Foreign currency monetary assets and liabilities are translated into the functional currency at rates of exchange ruling at the balance sheet date, or at the forward rate. Exchange differences are included in operating profit.

Assets and liabilities of overseas subsidiary and associated undertakings and joint ventures, including related goodwill, are translated into US dollars at rates of exchange ruling at the balance sheet date. The results and cash flows of overseas subsidiary and associated undertakings and joint ventures are translated into US dollars using average rates of exchange. Exchange adjustments arising when the opening net assets and the profits for the year retained by overseas subsidiary and associated undertakings and joint ventures are translated into US dollars are taken directly to reserves and reported in the statement of total recognized gains and losses. 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.

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, natural gas and power 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.

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, natural gas and power 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 and power 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 and power 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.

The effect of these policies on the accounts is described as follows:

Reporting in the income statement. Gains and losses on oil price contracts held for trading and for risk management purposes and natural gas and power price contracts held for trading purposes that are settled for difference in cash 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 borrowings 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 and power price derivatives held for risk management purposes 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 debtors or creditors 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 six 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 three years 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.

For oil, natural gas and power price futures and options traded on regulated exchanges, gains and losses are settled on a daily basis, while exchange liquidity requirements are funded through letters of credit or cash deposits. 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 used to manage interest rate exposures 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, natural gas and power price derivatives and all traded derivatives are included in net cash inflow from operating activities.

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.

Oil and natural gas exploration and development expenditure

Oil and natural gas exploration and development expenditure is accounted for using the successful efforts method of accounting.

Licence and property acquisition costs. Exploration and property leasehold acquisition costs are capitalized within intangible fixed assets and amortized on a straight-line basis over the estimated period of exploration. Each property is reviewed on an annual basis to confirm that drilling activity is planned and it is not impaired. If no future activity is planned the remaining balance of the licence and property acquisition costs is written off. Upon determination of economically recoverable reserves ('proved reserves' or 'commercial reserves'), amortization ceases and the remaining costs are aggregated with exploration expenditure and held on a field-by-field basis as proved properties awaiting approval within intangible fixed assets. When development is approved internally, the relevant expenditure is transferred to tangible production assets.

Exploration expenditure. Geological and geophysical exploration costs are charged against income as incurred. Costs directly associated with an exploration well are capitalized as an intangible asset until the drilling of the well is complete and the results have been evaluated. These costs include employee remuneration, materials and fuel used, rig costs, delay rentals and payments made to contractors. If hydrocarbons are not found, the exploration expenditure is written off as a dry hole. If hydrocarbons are found, and, subject to further appraisal activity which may include the drilling of further wells (exploration or exploratory-type stratigraphic test wells), are likely to be capable of commercial development, the costs continue to be carried as an asset. All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off. When proved reserves of oil and natural gas are determined and development is sanctioned, the relevant expenditure is transferred to tangible production assets.

Development expenditure. Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including unsuccessful development or delineation wells, is capitalized within tangible production assets.

Decommissioning

Provision for decommissioning is recognized in full on the installation of oil and natural gas production facilities. 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.

Depreciation

Oil and natural gas production assets are depreciated using a unit-of-production method. The cost of producing wells is amortized over proved developed reserves. Licence acquisition, decommissioning and field development costs are amortized over total proved reserves. The field development costs subject to amortization are expenditures incurred to date together with sanctioned future development expenditure.

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.

Petroleum revenue tax

The charge for petroleum revenue tax is calculated using a unit-of-production method.

Note 1 Accounting policies (continued)

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 (capital leases) are capitalized as tangible fixed assets at the estimated present value of underlying lease payments. The corresponding capital lease obligation is included within finance debt. Rentals under operating leases are charged against income as incurred.

Research

Expenditure on research is written off in the year in which it is incurred.

Interest

Interest is capitalized gross of related tax relief 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

For defined benefit pension and other postretirement benefit schemes, scheme assets are measured at fair value and scheme liabilities are measured on an actuarial basis using the projected unit method and discounted at an interest rate equivalent to the current rate of return on a high-quality corporate bond of equivalent currency and term to the scheme liabilities. Full actuarial valuations are obtained at least every three years and are updated at each balance sheet date. The resulting surplus or deficit, net of taxation thereon, is presented separately above the total for net assets on the face of the balance sheet.

The service cost of providing pension and other postretirement benefits to employees for the year is charged to the income statement. The cost of making improvements to pension and other postretirement benefits is recognized in the income statement on a straight-line basis over the period during which the increase in benefits vests. To the extent that the improvements in benefits vest immediately, the cost is recognized immediately. These costs are recognized as an operating expense.

A charge representing the unwinding of the discount on the scheme liabilities during the year is included within other finance expense. A credit representing the expected return on the scheme assets during the year is included within other finance expense. This credit is based on the market value of the scheme assets, and expected rates of return, at the beginning of the year.

Actuarial gains and losses may result from: differences between the expected return and the actual return on scheme assets; differences between the actuarial assumptions underlying the scheme liabilities and actual experience during the year; or changes in the actuarial assumptions used in the valuation of the scheme liabilities. Actuarial gains and losses, and taxation thereon, are recognized in the statement of total recognized gains and losses. For defined contribution schemes, contributions payable for the year are charged to the income statement as an operating expense.

Deferred taxation

Deferred tax is recognized in respect of all timing differences that have originated but not reversed at the balance sheet date where transactions or events have occurred at that date that will result in an obligation to pay more, or a right to pay less, tax in the future. In particular:

Provision is made for tax on gains arising from the disposal of fixed assets that have been rolled over into replacement assets, only to the extent that, at the balance sheet date, there is a binding agreement to dispose of the replacement assets concerned. However, no provision is made where, on the basis of all available evidence at the balance sheet date, it is more likely than not that the taxable gain will be rolled over into replacement assets and charged to tax only where the replacement assets are sold.

Provision is made for deferred tax that would arise on remittance of the retained earnings of overseas subsidiaries, joint ventures and associated undertakings only to the extent that, at the balance sheet date, dividends have been accrued as receivable.

Deferred tax assets are recognized only to the extent that it is considered more likely than not that there will be suitable taxable profits from which the underlying timing differences can be deducted. Deferred tax is measured on an undiscounted basis at the tax rates that are expected to apply in the periods in which timing differences reverse, based on tax rates and laws enacted or substantively enacted at the balance sheet date.

Discounting

The unwinding of the discount on provisions is included within other finance expense. Any change in the amount recognized for environmental and other provisions arising through changes in discount rates is included within other finance expense.

Use of estimates

The preparation of accounts in conformity with generally accepted accounting practice requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of accounts and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from these estimates.

Comparative figures

Information for 2003 and 2002 has been restated to reflect the transfer of natural gas liquids activities from Exploration and Production to Gas, Power and Renewables. In addition, certain prior year figures have been restated to conform with the 2004 presentation.

Note 2 Turnover

	Years ended December 31,		
	2004	2003	2002
	($ million)		
Sales and operating revenue	352,316	278,859	222,231
Customs duties and sales taxes	67,257	46,288	43,510
	285,059	232,571	178,721

Note 3 Production taxes

	Years ended December 31,		
	2004	2003	2002
	($ million)		
UK petroleum revenue tax	335	300	309
Overseas production taxes	1,814	1,423	965
	2,149	1,723	1,274

Note 4 Distribution and administration expenses

	Years ended December 31,		
	2004	2003	2002
	($ million)		
Distribution	13,577	12,559	11,431
Administration	1,411	1,513	1,201
	14,988	14,072	12,632

Note 5 Other income

	Years ended December 31,		
	2004	2003	2002
	($ million)		
Income from other fixed asset investments	76	157	139
Other interest and miscellaneous income	599	629	502
	675	786	641
Income from investments publicly traded included above	21	60	58

Note 6 Auditors' remuneration

	Years ended December 31,					
	2004		2003		2002	
	UK	Total	UK	Total	UK	Total
	($ million)					
Audit fees Ernst & Young						
Group audit	13	27	8	18	6	15
Audit-related regulatory reporting	4	7	2	5	2	4
Statutory audit of subsidiaries	4	16	3	13	2	10
	21	50	13	36	10	29
Fees for other services Ernst & Young						
Further assurance services						
Acquisition and disposal due diligence	6	7	9	9	9	13
Pension scheme audits		1		1		1
Other further assurance services	6	9	5	9	5	8
Tax services						
Compliance services	3	13	3	17	3	23
Advisory services		1		2	2	4
Other services					1	1
	15	31	17	38	20	50

Group audit fees include $4 million (2003 $2 million and 2002 $2 million) in respect of the parent company. Audit fees are included in the income statement within distribution and administration expenses.

The audit committee has established pre-approval policies and procedures for the engagement of Ernst & Young to render audit and certain assurance and tax services.

The audit fees payable to Ernst & Young are reviewed by the audit committee in the context of other global companies for cost effectiveness.

Ernst & Young performed further assurance and tax services which were not prohibited by regulatory or other professional requirements and were pre-approved by the committee. Ernst & Young is engaged for these services when their expertise and experience of BP are important.

Most of this work is of an audit nature. 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 paid to major firms of accountants other than Ernst & Young for other services amount to $82 million (2003 $44 million and 2002 $33 million).

Note 7 Exceptional items

Exceptional items comprise profit (loss) on sale of fixed assets and the sale of businesses or termination of operations, as follows:

		Years ended December 31,		
		2004	**2003**	**2002**
			($ million)	
Profit on sale of businesses or termination of operations	Group			195
Loss on sale of businesses or termination of operations	Group	(695)	(28)	(228)
		(695)	(28)	(33)
Profit on sale of fixed assets	Group	1,829	1,894	2,736
	Associated undertakings			2
Loss on sale of fixed assets	Group	(319)	(1,035)	(1,537)
		1,510	859	1,201
Exceptional items		815	831	1,168
Taxation credit (charge)				
Sale of businesses or termination of operations		238		45
Sale of fixed assets		23	(123)	(170)

	Years ended December 31,		
Exceptional items (net of tax)	1,076	708	1,043

Profit on sale of businesses or termination of operations

Refining and Marketing nil (2003 nil and 2002 $130 million). The profit in 2002 relates mainly to the disposal of the Group's retail network in Cyprus.

Gas, Power and Renewables nil (2003 nil and 2002 $65 million). The profit in 2002, arises principally from the sale of the Group's UK contract energy management business.

Loss on sale of businesses or termination of operations

Refining and Marketing $132 million (2003 $28 million and 2002 $12 million). The closure of the lubricants operation of the Coryton refinery in the UK and of refining operations at the ATAS refinery in Mersin, Turkey. For 2003, the sale of the Group's European oil speciality products business.

Gas, Power and Renewables nil (2003 nil and 2002 $69 million). For 2002, the withdrawal from solar thin film manufacturing.

Petrochemicals $563 million (2003 nil and 2002 $147 million). The sale of the speciality intermediate chemicals business; the sale of the Fabrics and Fibres business; the closure of two manufacturing plants at Hull, UK, which produced acids; and the closure of the linear alpha-olefins production facility at Pasadena, Texas. For 2002, the disposal of our plastic fabrications business; the sale of the former Burmah Castrol speciality chemicals business Fosroc Construction; and the provision for the loss on divestment of the former Burmah Castrol speciality chemicals businesses Sericol and Fosroc Mining.

Profit on sale of fixed assets

Exploration and Production $379 million (2003 $1,591 million and 2002 $531 million). The Group divested interests in a number of oil and natural gas properties in all three years. For 2004, this included interests in oil and natural gas properties in Australia, Canada and the Gulf of Mexico, and the reversal of the provision for the loss on sale of $217 million for the Desarrollo Zuli Occidental (DZO) and Boqueron fields in Venezuela (see below). For 2003, the divestment of a further 20% interest in BP Trinidad and Tobago LLC to Repsol; the sale of the Group's 96.14% interest in the Forties oil field in the UK North Sea; the sale of a package of UK Southern North Sea gas fields; and the divestment of our interest in the In Amenas gas condensate project in Algeria to Statoil. The significant element of the profit for 2002 is the gain on the redemption of certain preferred limited partnership interests BP retained following the Altura Energy common interest disposal in 2000 in exchange for BP loan notes held by the partnership.

Refining and Marketing $107 million (2003 $89 million and 2002 $561 million). The sale of the Cushing and other pipeline interests in the US and the churn of retail assets. In 2003, the divestment of pipeline interests in the US. For 2002, the profit on the sale of the Group's interest in the Colonial pipeline in the US and the profit on the sale of a US downstream electronic payment system.

Gas, Power and Renewables $56 million (2003 $11 million and 2002 $1,556 million). The divestment of BP's interest in two natural gas liquids plants in Canada. For 2003, the sale and leaseback of rail cars. The major part of the profit during 2002 arises from the divestment of the Group's shareholding in Ruhrgas.

Petrochemicals nil (2003 $55 million and 2002 $27 million). For 2003, the sale of our interest in AG International Chemical Company, a purified isophthalic acid associated undertaking in Japan and other minor divestments. In 2002, the divestment of two-thirds of our interest in the European ethylene pipeline company, ARG.

Other businesses and corporate $1,287 million (2003 $148 million and 2002 $63 million). The divestment of the Group's investments in PetroChina and Sinopec. In 2003, the Group sold its 50% interest in Kaltim Prima Coal, an Indonesian company, and certain other investments.

Loss on sale of fixed assets

Exploration and Production $227 million (2003 $678 million and 2002 $1,257 million). The Group divested interests in a number of oil and natural gas properties in all three years. For 2004, this included interests in oil and natural gas properties in Indonesia and the Gulf of Mexico. In 2003, this included losses on exploration and production properties in China, Norway and the US and the provision for losses on sale in early 2004 of exploration and production properties in Canada and Venezuela. In respect of Venezuela, the sales agreement for our interests in the DZO and Boqueron fields lapsed in early 2004, and the fields have been retained. The provision for a loss on disposal of $217 million recognized in 2003 was reversed in 2004 and an impairment charge of $186 million was recognized. The major element of the loss on sale of fixed assets for 2002 relates to provisions for losses on the sale of oil and natural gas properties in the US announced in early 2003.

Refining and Marketing $92 million (2003 $274 million and 2002 $67 million). The divestment of the Singapore refinery and retail churn. For 2003, retail churn and the sale of refinery and retail interests in Germany and Central Europe.

Gas, Power and Renewables nil (2003 $17 million and 2002 nil).

Petrochemicals nil (2003 $17 million and 2002 $136 million). For 2002, the closure of our polypropylene production facility at Cedar Bayou, Texas, a high density polyethylene unit at Deer Park, Texas, and one of four polypropylene units at Chocolate Bayou, Texas.

Other businesses and corporate nil (2003 $49 million and 2002 $77 million). For 2003 and 2002 the divestment of a number of minor investments.

Additional information on the sale of businesses and fixed assets is given in Note 20 Disposals.

Note 8 Interest expense

	Years ended December 31,		
	2004	**2003**	**2002**
		($ million)	
Bank loans and overdrafts	34	38	134
Other loans (a)	573	628	852
Capital leases	37	34	40
	644	700	1,026
Capitalized at 3% (2003 3% and 2002 4%) (b)	208	190	100
Group	436	510	926
Joint ventures	158	89	58
Associated undertakings	48	45	83
Total charged against profit	642	644	1,067

(a) Interest expense for 2003 includes a charge of $31 million (2002 $15 million) relating to early redemption of debt.

(b) Tax relief on capitalized interest is $73 million (2003 $68 million and 2002 $36 million).

Note 9 Other finance expense

	Years ended December 31,		
	2004	2003	2002
	($ million)		
Interest on pension and other postretirement benefit plan liabilities	2,012	1,840	1,671
Expected return on pension and other postretirement benefit plan assets	(1,983)	(1,500)	(1,810)
Interest net of expected return on plan assets	29	340	(139)
Unwinding of discount on provisions	196	173	170
Unwinding of discount on deferred consideration for acquisition of investment in TNK-BP	91	34	
Change in discount rate for provisions (a)	41		42
Total charged against profit	357	547	73

(a)

Revaluation of environmental and other provisions at a lower discount rate.

Note 10 Depreciation and amounts provided

Included in the income statement under the following headings:

	Years ended December 31,		
	2004	2003	2002
	($ million)		
Depreciation and amortization of goodwill and other intangibles			
Cost of sales	11,109	9,748	9,346
Distribution	1,334	1,044	952
Administration	128	148	90
	12,571	10,940	10,388
Amounts provided against fixed asset investments			
Cost of sales	12		13
	12,583	10,940	10,401
Depreciation of capitalized leased assets included above	164	46	49

The charge for depreciation and amortization of goodwill and other intangibles in 2004 includes asset write-downs and impairment charges of $1,743 million in total. Exploration and Production recognized a charge of $621 million for the impairment of certain assets. During the year, as a result of impairment triggers, reviews were conducted which have resulted in impairment charges of $83 million in respect of King's Peak in the Gulf of Mexico, $20 million in respect of two fields in the Gulf of Mexico Shelf Matagorda Island area and $184 million in respect of various US onshore fields. A charge of $88 million was reflected in respect of a gas processing plant in the US and a charge of $60 million following the blowout of the Temsah platform in Egypt. In addition, following the lapse of the sale agreement for DZO and Boqueron in Venezuela, an impairment charge of $186 million was reflected. In connection with the Solvay transactions, the Group has recognized impairment charges of $325 million

for goodwill and $306 million for tangible fixed assets in BP Solvay Polyethylene Europe. As part of a restructuring of the North American Olefins and Derivatives businesses, decisions were taken to exit certain businesses and facilities resulting in impairments and write-downs of $291 million. With the formation of Olefins and Derivatives and its planned divestment, certain agreements and assets have been restructured to reflect the arm's-length relationship that will exist in the future. This has resulted in a $188 million impairment of the facilities at Hull, UK. Other businesses and corporate recognized an impairment charge of $12 million for certain investments.

The 2003 charge for depreciation and amortization of goodwill and other intangibles includes asset write-downs and impairment charges on exploration and production properties of $738 million. This includes a charge of $296 million for four fields in the Gulf of Mexico following technical reassessment and re-evaluation of future investment options; charges of $133 million and $49 million respectively for the Miller and Viscount fields in the UK North Sea as a result of a decision not to proceed with waterflood and gas import options and a reserve write-down respectively; a charge of $105 million for the Yacheng field in China; a charge of $108 million for the Kepodang field in Indonesia; and $47 million for the Eugene Island/West Cameron fields in the US as a result of reserve write-downs following completion of our routine full technical reviews.

The charge for depreciation and amortization of goodwill and other intangibles in 2002 includes asset write-downs and impairment charges of $1,390 million in total. Exploration and Production recognized a charge of $1,091 million for the impairment of Shearwater in the North Sea, Rhourde El Baguel in Algeria, LL652 and Boqueron in Venezuela, Pagerungan in Indonesia and Badami in Alaska, following full technical reassessments and evaluations of future investment opportunities. In addition, the business took a $94 million write-off in respect of its Gas-to-Liquids plant in Alaska. Petrochemicals wrote down the value of its Indonesian manufacturing assets by $140 million following a review of immediate prospects and opportunities for future growth in a highly competitive regional market. Gas, Power and Renewables incurred an impairment charge of $30 million in respect of a cogeneration power plant in the UK. Refining and Marketing recognized an impairment charge of $35 million for its retail business in Venezuela.

In assessing the value in use of potentially impaired assets, a nominal discount rate of 9% before tax has been used. Asset values are determined by deriving the net present value of the future cash flows; the cash flows are adjusted for the risks specific to the asset.

Note 11 Rental expense under operating leases

	Years ended December 31,		
	2004	**2003**	**2002**
		($ million)	
Minimum rentals:			
Tanker charters	747	440	397
Plant and machinery	428	457	621
Land and buildings	555	548	342
	1,730	1,445	1,360
Less: Rentals from sub-leases	(109)	(128)	(166)
	1,621	1,317	1,194

Note 12 Research

Expenditure on research amounted to $439 million (2003 $349 million and 2002 $373 million).

Note 13 Currency exchange gains and losses

Accounted net foreign currency exchange gain included in the determination of profit for the year amounted to $41 million (2003 $171 million gain and 2002 $66 million gain).

Note 14 Taxation

Tax on profit on ordinary activities

	Years ended December 31,		
	2004	**2003**	**2002**
		($ million)	
Current tax:			
UK corporation tax	8,917	11,435	1,304
Overseas tax relief	(7,078)	(10,293)	(301)
	1,839	1,142	1,003
Overseas	5,070	3,525	1,883
Group	6,909	4,667	2,886
Joint ventures	880	158	75
Associated undertakings	119	94	187
	7,908	4,919	3,148
Deferred tax:			
UK	(140)	289	390
Overseas	340	931	779
Group	200	1,220	1,169
Joint ventures	170	(14)	
Associated undertakings	4	(14)	
	374	1,192	1,169
Tax on profit on ordinary activities	8,282	6,111	4,317

Included in the charge for the year is a credit of $261 million (2003 $123 million charge and 2002 $125 million charge) relating to exceptional items.

Tax included in statement of total recognized gains and losses

	Years ended December 31,		
	2004	2003	2002
	($ million)		
Current tax:			
UK	43		57
Overseas	(20)	(11)	(54)
	23	(11)	3
Deferred tax:			
UK	165	64	(1,105)
Overseas	(76)		(1,215)
	89	64	(2,320)
Tax included in statement of total recognized gains and losses	112	53	(2,317)

Factors affecting current tax charge

The following table provides a reconciliation of the UK statutory corporation tax rate to the effective current tax rate of the Group on profit before taxation.

	Years ended December 31,		
	2004	2003	2002
	($ million)		
Analysis of profit before taxation:			
UK	7,671	4,990	2,678
Overseas	16,572	11,773	8,511
	24,243	16,763	11,189
Taxation	8,282	6,111	4,317
Effective tax rate	34%	36%	39%
	(% of profit before tax)		
UK statutory corporation tax rate	30	30	30
Increase (decrease) resulting from:			
UK supplementary and overseas taxes at higher rates	8	10	9
Tax credits		(1)	(3)
Restructuring benefits	(2)	(2)	
Current year losses unrelieved (prior year losses utilized)	(2)	(3)	1

	Years ended December 31,		
No relief for inventory holding losses (inventory holding gains not taxed)	(2)	(1)	(2)
Acquisition amortization	3	4	7
Other	(1)	(1)	(3)
Effective tax rate	34	36	39
Current year timing differences	(1)	(6)	(11)
Effective current tax rate	33	30	28

Current year timing differences arise mainly from the excess of tax depreciation over book depreciation.

From January 1, 2005, the Group has adopted International Financial Reporting Standards (IFRS). As a consequence, there will be a change in the basis of providing deferred taxation in such areas as business combinations and the valuation of inventory, which will lead to changes to certain of the factors described below and may lead to a change in the Group's effective tax rate.

The Group earns income in many different countries and, on average, pays taxes at rates higher than the UK statutory rate. The overall impact of these higher taxes, which include the supplementary charge of 10% on UK North Sea profits, is subject to changes in enacted tax rates and the country mix of the Group's income. However, it is not expected to increase or decrease substantially in the near term.

The tax charge in 2002 reflected a benefit from US 'non-conventional fuel credits' which are no longer available after December 31, 2002. The effect of the loss of these credits on the overall tax charge was offset in 2003 by benefits from restructuring and planning initiatives.

The Group has around $7.7 billion ($4.5 billion) of carry-forward tax losses in the UK and Germany, which would be available to offset against future taxable income. At the end of 2004, no tax assets were recognized on these losses (at the end of 2003, $285 million of assets were recognized). Tax assets are recognized only to the extent that it is considered more likely than not that suitable taxable income will arise. Carry-forward losses in other taxing jurisdictions have not been recognized as deferred tax assets, and are unlikely to have a significant effect on the Group's tax rate in future years.

The Group's profit before taxation includes inventory holding gains or losses. These gains (or losses) are not taxed (or deductible) in certain jurisdictions in which the Group operates, and therefore give rise to decreases or increases in the effective tax rate. The impact of this item will be reduced under IFRS.

The impact on the tax rate of acquisition amortization (non-deductible depreciation and amortization relating to the fixed asset revaluation adjustments and goodwill consequent upon the Atlantic Richfield and Burmah Castrol acquisitions) is likely to be eliminated when the Group reports its results under IFRS.

The major component of timing differences in the current year is accelerated tax depreciation. Based on current capital investment plans, the Group expects to continue to be able to claim tax allowances in excess of depreciation in future years at a level similar to the current year.

Deferred tax

	At December 31, 2004	At December 31, 2003
	($ million)	
Analysis of provision:		
Depreciation	15,936	15,613
Other taxable timing differences	2,090	1,882
Petroleum revenue tax	(578)	(601)
Decommissioning and other provisions	(2,142)	(2,256)
Pensions and other postretirement benefits	(1,720)	(1,652)
Tax credit and loss carry forward	(51)	(105)
Other deductible timing differences	(205)	(162)
Deferred tax provision	13,330	12,719
of which UK	3,932	4,179
Overseas	9,398	8,540
Analysis of movements during the year:		
At January 1	12,719	10,894
Exchange adjustments	329	541
Charge for the year on ordinary activities	200	1,220
Charge for the year in the statement of total recognized gains and losses	89	64
Deletions/transfers	(7)	
At December 31	13,330	12,719
offset against Pensions	147	172
Other postretirement benefits	1,573	1,480
Disclosed as deferred taxation on the balance sheet	15,050	14,371

	Years ended December 31, 2004	2003	2002
	($ million)		
The charge for deferred tax on ordinary activities:			
Origination and reversal of timing differences	200	1,220	814
Effect of the introduction of supplementary UK corporation tax of 10% on opening liability			355
	200	1,220	1,169
The charge (credit) for deferred tax in statement of total recognized gains and losses:			
Origination and reversal of timing differences	89	64	(2,320)

	Years ended December 31,		

Note 15 Quarterly results of operations (unaudited)

	Group turnover	Profit before interest and tax	Profit for the period	Profit per ordinary share
		($ million)		(cents)
Year ended December 31, 2004				
First quarter	68,461	6,912	4,818	21.81
Second quarter	70,473	6,368	3,896	17.80
Third quarter	68,515	6,885	4,483	20.67
Fourth quarter	77,610	5,077	2,534	11.80
Total	285,059	25,242	15,731	72.08
Year ended December 31, 2003				
First quarter	62,031	6,332	4,219	18.90
Second quarter	54,426	3,665	1,585	7.19
Third quarter	58,250	4,113	2,344	10.62
Fourth quarter	57,864	3,844	2,334	10.56
Total	232,571	17,954	10,482	47.27
Year ended December 31, 2002				
First quarter	36,290	2,369	1,284	5.73
Second quarter	43,655	4,099	2,046	9.12
Third quarter	49,054	3,803	2,828	12.62
Fourth quarter	49,722	2,058	637	2.86
Total	178,721	12,329	6,795	30.33

Note 16 Dividends per ordinary share

	Years ended December 31,								
	2004	2003	2002	2004	2003	2002	2004	2003	2002
	(pence per share)			(cents per share)			($ million)		
First quarterly	3.807	3.947	4.051	6.75	6.25	5.75	1,483	1,386	1,290
Second quarterly	3.860	4.039	3.875	7.10	6.50	6.00	1,535	1,433	1,346
Third quarterly	3.910	3.857	3.897	7.10	6.50	6.00	1,530	1,438	1,340
Fourth quarterly	4.522	3.674	3.815	8.50	6.75	6.25	1,821	1,494	1,397
	16.099	15.517	15.638	29.45	26.00	24.00	6,369	5,751	5,373

Note 17 Profit per ordinary share

	Years ended December 31,		
	2004	2003	2002
	(cents per share)		
Basic earnings per share	72.08	47.27	30.33
Diluted earnings per share	70.79	46.83	30.19

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 outstanding during the year. The profit attributable to ordinary shareholders is $15,729 million (2003 $10,480 million and 2002 $6,793 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, adjusted for the unwinding of the discount on the deferred consideration for the acquisition of our interest in TNK-BP, of $15,793 million (2003 $10,504 million and 2002 $6,793 million). The number of shares outstanding is adjusted to show the potential dilution if employee share options are converted into ordinary shares, and for the ordinary shares issuable, in two further annual tranches, in respect of the TNK-BP joint venture. The number of ordinary shares outstanding for basic and diluted earnings per share may be reconciled as follows:

	Years ended December 31,		
	2004	2003	2002
	(shares thousand)		
Weighted average number of ordinary shares	21,820,535	22,170,741	22,397,126
Potential dilutive effect of ordinary shares issuable under employee share schemes	74,775	71,651	107,322
Potential dilutive effect of ordinary shares issuable as consideration for BP's interest in the TNK-BP joint venture	415,016	186,980	
	22,310,326	22,429,372	22,504,448

Note 18 Operating lease commitments

Annual commitments under operating leases were as follows:

	December 31,			
	2004		2003	
	Land and buildings	Other	Land and buildings	Other
	($ million)			
Expiring within: 1 year	79	359	70	186
2 to 5 years	180	261	173	388
Thereafter	268	387	262	291
	527	1,007	505	865

The minimum future lease payments (after deducting related rental income from operating sub-leases of $496 million) were as follows:

	December 31, 2004
	($ million)
2005	1,483
2006	1,106
2007	944
2008	858
2009	754
Thereafter	3,209
	8,354

Note 19 Acquisitions

	Year ended December 31, 2004		
	Book value on acquisitions	Fair value adjustments	Fair value
	($ million)		
Intangible fixed assets	15		15
Tangible fixed assets	703	636	1,339
Current assets (excluding cash)	721		721
Cash at bank and in hand	36		36
Other creditors	(329)		(329)
Pension liability	(3)		(3)
Net investment in equity-accounted entities transferred to full consolidation	(547)	(94)	(641)
Net assets acquired	596	542	1,138
Negative goodwill			(61)
Goodwill			328
Consideration			1,405

Acquisitions in 2004

On November 2, 2004, Solvay exercised its option to sell its interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America to BP. Solvay held 50% of BP Solvay Polyethylene Europe and 51% of BP Solvay Polyethylene North America. On completion, the two entities, which manufacture and market high-density polyethylene, became wholly owned subsidiaries of BP. The total consideration for the acquisition was $1,391 million. The consideration is subject to final closing adjustments. Other minor acquisitions were made for a total consideration of $14 million. All business combinations have been accounted for using the acquisition method of accounting. The fair value of the tangible fixed assets has been estimated by determining the net present value of future cash flows. No significant adjustments were made to the other assets and liabilities acquired. The assets and liabilities acquired as part of the 2004 acquisitions are shown in aggregate in the table above.

During the year, BP China and Sinopec announced the establishment of the BP-Sinopec (Zhejiang) Petroleum Co. Ltd, a retail joint venture between BP and Sinopec. Based on the existing service station network of Sinopec, the new joint venture will build, operate and manage a network of 500 service stations in Hangzhou, Ningbo and Shaoxing. Also during the year, BP China and PetroChina announced the establishment of BP-PetroChina Petroleum Company Limited. Located in Guangdong, one of the most developed provinces in China, the joint venture will acquire, build, operate and manage 500 service stations in the province. The initial investment in both joint ventures amounted to $106 million.

Acquisitions in 2003

BP made a number of minor acquisitions in 2003 for a total consideration of $82 million. All these business combinations were accounted for using the acquisition method of accounting. No significant fair value adjustments were made to the acquired assets and liabilities. Goodwill of $5 million arose on these acquisitions. In addition the Group redeemed the outstanding stock in CH-Twenty, Inc., a subsidiary undertaking, for $150 million.

TNK-BP

On August 29, 2003 BP and the Alfa Group and Access-Renova (AAR) combined certain of their Russian and Ukranian oil and gas businesses to create TNK-BP, a new company owned and managed 50:50 by BP and AAR. TNK-BP is a joint venture and accounted for under the gross equity method. BP contributed its 29% interest in Sidanco, its 29% interest in Rusia Petroleum and its holding in the BP Moscow retail network. There was additional consideration from BP to AAR comprising an immediate $2,604 million in cash (which was subsequently reduced by receipt of pre-acquisition dividends net of other adjustments, of $298 million) together with annual tranches of $1,250 million in BP shares payable in 2004, 2005 and 2006. There were costs of $45 million in connection with the transaction. The first tranche was issued in September 2004. BP also agreed with AAR to incorporate AAR's 50% interest in Slavneft into TNK-BP in return for $1,418 million in cash (which was subsequently reduced by receipt of pre-acquisition dividends of $64 million to $1,354 million). This transaction was completed on January 16, 2004.

Acquisitions in 2002

During the year BP acquired the whole of Veba Oil (Veba) from E.ON in two stages. Veba owns Aral, Germany's biggest fuels retailer. In February BP paid $1,072 million to subscribe for new shares issued by Veba and acquired $1,520 million of outstanding loans from E.ON to Veba in return for a 51% interest in and operational control of Veba. In addition, there were acquisition expenses of $30 million. Subsequently, on June 30, BP paid E.ON a further $2,386 million to acquire the remaining 49% of Veba. There were further acquisition expenses of $30 million. The total consideration of $5,038 million was subject to final closing adjustments. As well as a refining and marketing business, Veba also had an exploration and production business. With the exception of the Cerro Negro field in Venezuela, the whole of these activities was sold in May 2002, mainly to Petro-Canada. These activities represent the Businesses held for resale in the table set out below.

Other transactions in 2002 included buying our co-venturers' 15% interest in the Atlantic Richfield polypropylene joint venture and acquiring the 51% BP did not own in certain Chinese LPG ventures. All these business combinations have been accounted for using the acquisition method of accounting. The assets and liabilities acquired as part of the 2002 acquisitions are shown in aggregate in the table below. The identifiable assets and liabilities of Veba were not revalued on the acquisition of the 49% minority interest in June, as the difference between the fair values and the carrying amounts of the assets and liabilities was not material. Additional goodwill of $203 million was originally recognized on the acquisition of the minority interest in Veba. This has been reduced to $61 million following the revisions to the fair values described below.

The fair values of the assets and liabilities of Veba included in the accounts for the year ended December 31, 2002 have been subject to further investigation and review during 2003, as permitted by Financial Reporting Standard No. 7 'Fair Values in Acquisition Accounting'. The revisions to the previously reported fair values are as set out below.

	Fair value as previously reported	Revisions	Final fair value
		($ million)	
Intangible fixed assets			
Tangible fixed assets	4,945	(76)	4,869
Fixed assets Investments	122		122
Businesses held for resale	1,369		1,369
Current assets (excluding cash)	3,031		3,031
Cash at bank and in hand	1,118		1,118
Finance debt	(1,002)		(1,002)
Other creditors	(3,394)	365	(3,029)
Deferred taxation	(6)		(6)
Other provisions	(1,107)		(1,107)
Net investment in equity-accounted entities transferred to full consolidation	(191)		(191)
Net assets acquired	4,885	289	5,174
Minority interests	(2,201)	(142)	(2,343)
Goodwill	342	(147)	195
Consideration	3,026		3,026

Note 20 Disposals

As part of the strategy to upgrade the quality of its asset portfolio, the Group has an active programme to dispose of non-strategic assets. In the normal course of business in any particular year, the Group may sell interests in exploration and production properties, service stations and pipeline interests as well as non-core businesses. Disposal proceeds also include monies received from the repayment of loans.

Cash received during the year from disposals amounted to $5.0 billion (2003 $6.4 billion and 2002 $6.8 billion). The major transactions in 2004 which generated over $2.3 billion of proceeds were the sale of the Group's investments in PetroChina and Sinopec.

For 2003, the major disposals representing over $3.0 billion of the proceeds were the divestment of a further 20% interest in BP Trinidad and Tobago LLC; the sale of 50% of our interest in the In Amenas gas condensate project and 49% of our interest in the In Salah gas development in Algeria; and the sale of the UK North Sea Forties oil field, together with a package of 61 shallow-water assets in the Gulf of Mexico. The major asset transactions during 2002, generating proceeds of over $4.7 billion included the sale of the Group's shareholding in Ruhrgas, the sale of the Veba exploration and production operations and the divestment of certain US downstream assets. The principal transactions generating the proceeds for each segment are described below.

Exploration and Production $921 million (2003 $4,867 million and 2002 $794 million). The Group divested interests in a number of oil and natural gas properties in all three years. During 2004, in the US we sold 45% of our interest in King's Peak in the deepwater Gulf of Mexico to Marubeni Oil & Gas; divested our interest in Swordfish; and additionally, we sold various properties including our interest in the South Pass 60 property in the Gulf of Mexico Shelf. In Canada, BP sold various assets in Alberta to Fairborne Energy. In Indonesia, we disposed of our interest in the Kangean Production Sharing Contract and our participating interest in the Muriah Production Sharing Contract. In 2003, the UK North Sea Forties oil field, together with a package of 61 shallow-water assets in the Gulf of Mexico, were sold to Apache. A 12.5% interest in the Tangguh liquefied natural gas project in Indonesia was sold to CNOOC. Interests in 14 UK Southern North Sea gas fields, together with associated pipelines and onshore processing facilities, including the Bacton terminal, were sold to Perenco. BP sold 50% of its interest in the In Amenas gas condensate project and 49% of its interest in the In Salah gas development in Algeria to Statoil. In January 2003, Repsol exercised its option to acquire a further 20% interest in BP Trinidad and Tobago LLC. BP's interest in the company is now 70%. In February 2003, BP called its $420 million Exchangeable Bonds which were exchangeable for Lukoil American Depositary Shares (ADSs). Bondholders converted to ADSs before the redemption date. During 2002, the Group sold a number of minor oil and natural gas properties and completed the divestment of the Group's interest in the Kashagan discovery in Kazakhstan.

Refining and Marketing $906 million (2003 $1,053 million and 2002 $1,580 million). The churn of retail assets represents a significant element of the total in all three years. In addition, for 2004, major asset transactions included the sale of the Singapore refinery, and the Cushing and other pipeline interests in the US. As a condition of the approval of the acquisition of Veba in 2002, BP was, amongst other things, required to divest approximately 4% of its retail market share in Germany and a significant portion of its Bayermoil refining interests. The sale of 494 retail sites in the northern and northeastern part of Germany to PKN Orlen and the sale of retail and refinery assets in Germany and Central Europe to OMV in 2003 completed the divestments required. In addition, for 2002, the major transactions were the sale of a US downstream electronic payment system, the Group's interest in the Colonial pipeline in the USA, the refinery at Yorktown, Virginia and the downstream retail business in Cyprus.

Petrochemicals $717 million (2003 $236 million and 2002 $207 million). In 2004, these related principally to the sale of the speciality intermediate chemicals and Fabrics and Fibres businesses. For 2003, the proceeds related mainly to the completion of the divestment of the former Burmah Castrol speciality chemicals business Sericol and Fosroc Mining. In 2002, the Group sold its plastic fabrication business. In addition BP sold two-thirds of its interest in the European ethylene pipeline company, ARG, in accordance with EU Commission requirements in relation to the Veba acquisition.

Gas, Power and Renewables $144 million (2003 $67 million and 2002 $2,551 million). In 2004, the Group sold its interest in two Canadian natural gas liquids plants. In 2003, the Group entered into a sale and leaseback transaction for NGL railcars and received certain loan repayments. For 2002 in addition to the sale of the Group's interest in Ruhrgas, proceeds were received from the sale and leaseback of a solar manufacturing facility in Spain and an LNG tanker.

Other businesses and corporate $2,360 million (2003 $209 million and 2002 $1,650 million). The disposal of the Group's investments in PetroChina and Sinopec were the major transactions in 2004. In 2003, the Group sold its 50% interest in PT Kaltim Prima Coal, an Indonesian company. For 2002, the principal transaction was the sale in May of the Veba exploration and production operations acquired earlier in the year.

Total proceeds received for disposals represent the following amounts shown in the cash flow statement:

	Years ended December 31,		
	2004	2003	2002
		($ million)	
Proceeds from the sale of businesses	725	179	1,974
Proceeds from the sale of fixed assets	4,323	6,253	2,470
Proceeds from the sale of investment in Ruhrgas			2,338
	5,048	6,432	6,782

	Years ended December 31,		
	2004	2003	2002
The disposals comprise the following:		($ million)	
Intangible assets	215	322	205
Tangible assets (a)	2,549	6,212	2,545
Fixed asset Investments	1,197	890	1,769
Net assets of businesses held for resale			1,369
Finance debt		(420)	(1,135)
Current assets less current liabilities	417	(498)	533
Other provisions	(105)	(971)	(109)
	4,273	5,535	5,177
Profit (loss) on sale of businesses or termination of operations	(695)	(28)	(33)
Profit (loss) on sale of fixed assets	1,510	859	1,199
Total consideration	5,088	6,366	6,343
Decrease (increase) in amounts receivable from disposals	(40)	66	439
Net cash inflow	5,048	6,432	6,782

(a) 2003 includes provision for loss on disposal of $275 million (2002 $1,204 million).

Note 21 Intangible assets

	Goodwill	Negative goodwill	Total goodwill	Exploration expenditure	Other intangibles	Total
			($ million)			
Cost						
At January 1, 2004	14,384		14,384	4,977	833	20,194
Exchange adjustments	451		451	41	57	549
Acquisitions	328	(61)	267		15	282
Additions				754	246	1,000
Transfers				(1,036)		(1,036)
Deletions	(96)		(96)	(425)		(521)
At December 31, 2004	15,067	(61)	15,006	4,311	1,151	20,468
Depreciation						
At January 1, 2004	5,215		5,215	741	596	6,552
Exchange adjustments	194		194	1	40	235
Charge for the year	1,761		1,761	274	72	2,107
Transfers				(196)		(196)
Deletions	(36)		(36)	(270)		(306)
At December 31, 2004	7,134		7,134	550	708	8,392
Net book amount						
At December 31, 2004	7,933	(61)	7,872	3,761	443	12,076
At December 31, 2003	9,169		9,169	4,236	237	13,642

Note 22 Tangible assets

Property, plant and equipment:

	Land	Buildings	Oil and gas properties	Plant, machinery and equipment	Fixtures fittings and office equipment	Transport-ation	Oil depots storage tanks and service stations	Total	Of which: Assets under construction
					($ million)				
Cost									
At January 1, 2004	4,442	3,745	96,991	46,413	3,482	11,738	8,969	175,780	13,957
Exchange adjustments	493	71	1,641	2,461	37	182	718	5,603	158
Acquisitions	10			1,329				1,339	
Additions	308	121	8,048	2,201	513	852	861	12,904	10,084
Transfers			1,036					1,036	(8,879)
Deletions	(123)	(415)	(3,749)	(2,770)	(314)	(365)	(688)	(8,424)	(282)
At December 31, 2004	5,130	3,522	103,967	49,634	3,718	12,407	9,860	188,238	15,038
Depreciation									
At January 1, 2004	702	1,351	50,028	19,590	1,793	6,324	4,081	83,869	
Exchange adjustments	90	9	948	1,064	3	83	365	2,562	
Charge for the year	50	116	5,871	3,182	334	278	907	10,738	
Transfers			196					196	
Deletions	(89)	(285)	(3,031)	(1,539)	(370)	(202)	(359)	(5,875)	
At December 31, 2004	753	1,191	54,012	22,297	1,760	6,483	4,994	91,490	
Net book amount									
At December 31, 2004	4,377	2,331	49,955	27,337	1,958	5,924	4,866	96,748	15,038
At December 31, 2003	3,740	2,394	46,963	26,823	1,689	5,414	4,888	91,911	13,957

Assets held under capital leases, capitalized interest, decommissioning assets and land at net book amount included above:

	Leased assets			Capitalized interest		
	Cost	Depreciation	Net	Cost	Depreciation	Net
	($ million)			($ million)		
At December 31, 2004	2,831	1,127	1,704	3,881	2,547	1,334
At December 31, 2003	2,737	955	1,782	3,281	2,127	1,154

	Decommissioning asset		
	Cost	Depreciation	Net
	($ million)		
At December 31, 2004	4,425	1,908	2,517
At December 31, 2003	3,686	1,606	2,080

		Leasehold land	
	Freehold land	Over 50 years unexpired	Other
	($ million)		
At December 31, 2004	4,177	116	84
At December 31, 2003	3,466	71	203

Note 23 Fixed assets investments

	Joint ventures		Associated undertakings					
	Net assets (liabilities)	Loans	Net assets (liabilities)	Loans	Other Loans	Listed investments (a)	Other (b)	Total
	($ million)							
Cost								
At January 1, 2004	9,789	1,220	3,992	1,076	129	1,284	179	17,669
Exchange adjustments	18		44	9	1	20	6	98
Additions and net movements in joint ventures and associated undertakings	494	(155)	117	682				1,138
Acquisitions	1,472							1,472
Transfers	(387)		20	(180)				(547)
Deletions			(73)	(57)	(55)	(1,041)	(28)	(1,254)
At December 31, 2004	11,386	1,065	4,100	1,530	75	263	157	18,576
Amounts provided								
At January 1, 2004			21	177	2		11	211
Exchange adjustments			1				3	4
Provided in the year							12	12
Transfers								
Deletions				(57)				(57)
At December 31, 2004			22	120	2		26	170
Net book amount								
At December 31, 2004	11,386	1,065	4,078	1,410	73	263	131	18,406
At December 31, 2003	9,789	1,220	3,971	899	127	1,284	168	17,458

(a) The market value of listed investments at December 31, 2004 was $543 million ($3,212 million at December 31, 2003).

(b) Other investments are not publicly traded.

Note 24 Inventories

	At December 31, 2004	At December 31, 2003
	($ million)	
Petroleum	9,612	6,623
Chemicals	1,771	1,165
Other	474	961
	11,857	8,749
Stores	925	938
	12,782	9,687
Trading stocks	2,916	1,930
	15,698	11,617
Replacement cost	15,765	11,717

Note 25 Receivables

	December 31, 2004		December 31, 2003	
	Within 1 year	After 1 year (a)	Within 1 year	After 1 year (a)
	($ million)			
Trade receivables	31,223		23,487	
Other receivables:				
Joint ventures	14		44	
Associated undertakings	210	23	337	53
Prepayments and accrued income	7,188	1,874	3,445	2,023
Taxation recoverable	157	2	78	14
Other	5,603	402	3,993	428
	13,172	2,301	7,897	2,518

Provisions for doubtful debts deducted from Trade receivables amounted to $526 million ($441 million at December 31, 2003).

(a) See Note 50 US generally accepted accounting principles.

Note 26 Current assets investments

	At December 31,	
	2004	2003
	($ million)	
Publicly traded UK	21	42
Foreign	42	37
	63	79
Not publicly traded	265	106
	328	185
Stock exchange value of publicly traded investments	63	79

Note 27 Financial instruments

Financial instruments comprise primary financial instruments (cash, fixed and current asset investments, receivables, payables, finance debt and provisions) and derivative financial instruments (interest rate contracts, foreign exchange contracts, oil price contracts and natural gas price contracts and power price contracts). Interest rate contracts include futures contracts, swap agreements and options. Foreign exchange contracts include forwards, futures contracts, swap agreements and options. Oil, natural gas and power price contracts are those that require settlement in cash and include futures contracts, swap agreements and options. Oil, natural gas and power price contracts that require physical delivery are not financial instruments. However, if it is normal market practice for a particular type of oil, natural gas and power contract, despite having contract terms that require settlement by delivery, to be extinguished other than by physical delivery (e.g., by cash payment) it is called a cash-settled commodity contract. Contracts of this type are included with derivatives in the disclosures in Notes 28 and 29.

With the exception of the table of currency exposures shown on page F-46, short-term receivables and payables that arise directly from the Group's operations have been excluded from the disclosures contained in this note, as permitted by Financial Reporting Standard No. 13 'Derivatives and Other Financial Instruments: Disclosures'.

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.

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, 2004			December 31, 2003		
		Finance debt	Other financial liabilities	Total	Finance debt	Other financial liabilities	Total
		($ million)					
Due within:	1 year	10,184		10,184	9,456		9,456
	1 to 2 years	3,046	2,049	5,095	2,702	2,087	4,789
	2 to 5 years	6,105	744	6,849	5,105	1,834	6,939
	Thereafter	3,756	1,577	5,333	5,062	1,990	7,052
		23,091	4,370	27,461	22,325	5,911	28,236

Interest rate and currency of financial liabilities

The interest rate and currency profile of the financial liabilities of the Group, at December 31, 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	Amount	Total
	(%)	(Years)	($ million)	(%)	($ million)	(Years)	($ million)	($ million)
At December 31, 2004								
Finance debt								
US dollar	7	11	707	3	21,789			22,496
Sterling				5	96			96
Other currencies	9	15	167	4	332			499
			874		22,217			23,091
Other financial liabilities								
US dollar	3	2	1,522	5	573	5	1,847	3,942
Sterling						4	193	193
Other currencies	4	4	15	2	46	4	174	235
			1,537		619		2,214	4,370
Total			2,411		22,836		2,214	27,461
At December 31, 2003								
Finance debt								
US dollar	8	14	578	2	20,991			21,569
Sterling				4	107			107
Other currencies	9	15	141	3	508			649
			719		21,606			22,325
Other financial liabilities								
US dollar	3	3	2,899	5	242	4	1,817	4,958
Sterling						5	267	267
Other currencies	5	4	303			6	383	686
			3,202		242		2,467	5,911
Total			3,921		21,848		2,467	28,236

	December 31, 2004	December 31, 2003
	($ million)	
Analysis of the above financial liabilities by balance sheet caption:		
Current liabilities falling due within one year		
Finance debt	10,184	9,456
Noncurrent liabilities		
Finance debt	12,907	12,869
Accounts payable and accrued liabilities	2,978	4,480
Provisions for liabilities and charges		
Other	1,392	1,431
	27,461	28,236

The other financial liabilities comprise various accruals, sundry creditors and provisions relating to the Group's normal commercial operations, with payment dates spread over a number of years.

The proportion of floating rate debt at December 31, 2004 was 96% of total finance 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 finance debt and hedges described above, it is estimated that a change of 1% in the general level of interest rates on January 1, 2005 would change 2005 profit before tax by approximately $215 million.

Interest rate swaps and futures are used by the Group to modify the interest characteristics of its long-term finance debt 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 as at December 31.

	December 31, 2004	December 31, 2003
	($ million except percentages)	
Receive fixed rate swaps notional amount	8,182	7,432
Average receive fixed rate	3.1%	3.1%
Average pay floating rate	2.3%	1.1%

Currency exchange rate risk

The monetary assets and monetary liabilities of the Group in currencies other than in the functional currency of individual operating units are summarized below. These currency exposures arise from normal trading activities.

	Net foreign currency monetary assets (liabilities)				
	US dollar	Sterling	Euro	Other	Total
	($ million)				
At December 31, 2004					
US dollar		374	2	(942)	(566)
Sterling	314		380	66	760
Other	(269)	(51)	(25)	(237)	(582)
	45	323	357	(1,113)	(388)
At December 31, 2003					
US dollar		191	(24)	39	206
Sterling	67		308	34	409
Other	(1,148)	(25)	(27)	(131)	(1,331)
	(1,081)	166	257	(58)	(716)

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 table in Note 29.

Interest rate and currency of financial assets

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	Amount	Total
	(%)	(Years)	($ million)	(%)	($ million)	(Years)	($ million)	($ million)
At December 31, 2004								
US dollar	10	11	72	4	186	5	252	510
Sterling	8	2	101	2	292	3	242	635
Other currencies				2	510	1	695	1,205
			173		988		1,189	2,350
At December 31, 2003								
US dollar				2	656	2	154	810
Sterling	8	2	91	3	907	2	257	1,255
Other currencies	3	2	19	1	189	1	1,866	2,074
			110		1,752		2,277	4,139

	December 31,	
	2004	2003
	($ million)	
Analysis of the above financial assets by balance sheet caption:		
Fixed assets Investments	464	1,579
Current assets		
Receivables amounts falling due after more than one year	402	428
Investments	328	185
Cash at bank and in hand	1,156	1,947
	2,350	4,139

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

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, natural gas and power prices. In addition, the Group trades derivatives in conjunction with these risk management activities.

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.

	Not recognized in the accounts			Carried forward in the balance sheet		
	Gains	Losses	Total	Gains	Losses	Total
	($ million)					
Gains and losses at January 1, 2004	331	(130)	201	1,003	(425)	578
of which accounted for in income in 2004	98	(28)	70	438	(75)	363
Gains and losses at December 31, 2004	487	(408)	79	1,063	(364)	699
of which expected to be recognized in income in 2005	259	(267)	(8)	265	(77)	188
Gains and losses at January 1, 2003	526	(450)	76	352	(28)	324
of which accounted for in income in 2003	96	(51)	45	200	(14)	186
Gains and losses at December 31, 2003	331	(130)	201	1,003	(425)	578
of which expected to be recognized in income in 2004	98	(28)	70	438	(75)	363

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, 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.

	December 31,			
	2004		2003	
	Fair value asset	Fair value liability	Fair value asset	Fair value liability
	($ million)			
Interest rate contracts				
Foreign exchange contracts	36	(90)	30	(54)
Oil price contracts	1,162	(1,177)	586	(667)
Natural gas price contracts	802	(624)	858	(711)
Power price contracts	82	(12)	548	(514)
	2,082	(1,903)	2,022	(1,946)

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.

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, natural gas and power 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, natural gas and power price exposure also includes cash-settled commodity contracts such as forward contracts.

The following table shows values at risk for trading activities.

	Years ended December 31,							
	2004				2003			
	High	Low	Average	Year end	High	Low	Average	Year end
	($ million)							
Interest rate trading	1				1			
Foreign exchange trading	4	1	1	1	4		2	1
Oil price trading	55	18	29	45	34	17	26	27
Natural gas price trading	23	6	13	10	29	4	16	18
Power price trading	10	1	4	4	13		4	6

The presentation of trading results shown in the table below includes certain activities of BP's trading units which involves the use of derivative financial instruments in conjunction with physical and paper trading of oil, natural gas and power. It is considered that a more comprehensive representation of the Group's oil, natural gas and power price trading activities is given by aggregating the gain or loss on such derivatives together with the gain or loss arising from the physical and paper trades to which they relate, representing the net result of the trading portfolio.

	Years ended December 31,	
	2004	2003
	Net gain (loss)	Net gain (loss)
	($ million)	
Interest rate trading	4	9
Foreign exchange trading	136	118
Oil price trading	1,371	825
Natural gas price trading	461	341
Power price trading	160	119
	2,132	1,412

Note 29 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. Interest rate contracts include futures contracts, swap agreements and options. Foreign exchange contracts include forward and futures contracts, swap agreements and options. Oil, natural gas and power price contracts include futures contracts, swap agreements and options and cash-settled commodity contracts such as forward contracts.

Short-term receivables and payables that arise directly from the Group's operations have been excluded from the disclosures contained in this note, as permitted by Financial Reporting Standard No. 13 'Derivatives and Other Financial Instruments: Disclosures'.

The fair value and carrying amounts of finance debt shown below 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 table below include debt that matures in the year from December 31, 2004, 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.

		December 31,			
		2004		2003	
		Net fair value asset (liability)	Net carrying amount asset (liability)	Net fair value asset (liability)	Net carrying amount asset (liability)
		($ million)			
Primary financial instruments					
Fixed assets	Investments	748	464	3,507	1,579
Current assets					
Other receivables	amounts falling due after more than one year	402	402	428	428
Investments		328	328	185	185
Cash at bank and in hand		1,156	1,156	1,947	1,947
Finance debt					
Short-term borrowings		(5,003)	(5,003)	(5,059)	(5,059)
Long-term borrowings		(16,800)	(16,344)	(16,190)	(15,559)
Net obligations under capital leases		(2,608)	(2,579)	(2,479)	(2,452)
Noncurrent liabilities					
Accounts payable and accrued liabilities		(2,978)	(2,978)	(4,480)	(4,480)
Provisions for liabilities and charges					
Other		(1,392)	(1,392)	(1,431)	(1,431)
Derivative financial or commodity instruments					
Risk management	interest rate contracts	(73)		5	
	foreign exchange contracts	1,084	835	941	745
	oil price contracts	7	7	(5)	(5)
	natural gas price contracts.	35	35	(5)	(5)
	power price contracts			(10)	(10)
Trading	interest rate contracts				
	foreign exchange contracts	(54)	(54)	(24)	(24)
	oil price contracts	(15)	(15)	(81)	(81)
	natural gas price contracts.	178	178	147	147
	power price contracts	70	70	34	34

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 capital 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. Deferred consideration for the acquisition of our interest in TNK-BP is discounted to the present value of the future payments. The carrying value thus approximates the fair value. The remaining 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 instruments and cash-settled commodity contracts. 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, natural gas and power price contracts (futures contracts, swap agreements, options and forward contracts) are based on market prices.

Note 30 Finance debt

	December 31, 2004			December 31, 2003		
	Within 1 year (a)	After 1 year	Total	Within 1 year (a)	After 1 year	Total
	($ million)					
Bank loans	250	457	707	205	253	458
Other loans	9,819	10,167	19,986	9,161	10,524	19,685
Total borrowings	10,069	10,624	20,693	9,366	10,777	20,143
Net obligations under capital leases	115	2,283	2,398	90	2,092	2,182
	10,184	12,907	23,091	9,456	12,869	22,325

(a) Amounts due within one year include current maturities of long-term debt.

Where finance debt is swapped into another currency, the finance debt is accounted in the swap currency and not in the original currency of denomination. Total finance debt includes an asset of $835 million (an asset of $745 million at December 31, 2003) 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 $2,487 million (December 31, 2003 $2,503 million) with maturity periods ranging up to 34 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 finance debt.

At December 31, 2004, the Group had substantial amounts of undrawn borrowing facilities available, including committed facilities of $4,500 million expiring in 2005 ($3,700 million expiring in 2004). These facilities are with a number of international banks and borrowings under them would be at pre-agreed rates. The Group expects to renew the facilities on an annual basis. Certain of these facilities support the Group's commercial paper programme.

At December 31, 2004, the Group's share of third party finance debt of joint ventures and associated undertakings was $2,821 million (December 31, 2003 $2,151 million) and $1,048 million (December 31, 2003 $922 million) respectively. These amounts are not reflected in the Group's debt on the balance sheet.

Analysis of borrowing by year of repayment		December 31, 2004			December 31, 2003		
		Bank loans	Other loans	Total	Bank loans	Other loans	Total
		($ million)					
Due after	10 years	1	773	774		721	721
Due within	10 years	29	1	30		17	17
	9 years	20	5	25		337	337
	8 years	22	365	387		291	291
	7 years	28	286	314			
	6 years	36	99	135	7	1,700	1,707
	5 years	33	1,691	1,724	7	938	945
	4 years	29	1,510	1,539	8	1,291	1,299
	3 years	251	2,431	2,682	193	2,593	2,786
	2 years	8	3,006	3,014	38	2,636	2,674
		457	10,167	10,624	253	10,524	10,777
	1 year	250	9,819	10,069	205	9,161	9,366
		707	19,986	20,693	458	19,685	20,143

Amounts included above repayable by instalments, part of which falls due after five years from December 31, are as follows:

	At December 31,	
	2004	2003
	($ million)	
After five years	204	14
Within five years	76	82
	280	96

Interest rates on borrowings repayable wholly or partly more than five years from December 31, 2004 range from 1% to 12% with a weighted average of 4%. The weighted average interest rate on finance debt is 3%.

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, 2004
	($ million)
2005	152
2006	254
2007	258
2008	268
2009	280
Thereafter	3,540
	4,752
Less: amount representing lease interest	(2,354)
Present value of net minimum capital lease payments	2,398
of which due within one year	117
due after one year	2,281

The following information is presented in compliance with the requirements of US GAAP.

Bank and other loans long term

	Weighted average interest rate at December 31,		December 31,	
	2004	2003	2004	2003
	(%)		($ million)	
US dollar	3	3	10,374	10,427
Sterling	5	4	25	30
Other currencies	7	5	225	320
			10,624	10,777

Bank and other loans short term

	December 31,	
	2004	2003
	($ million)	
Current maturities of long-term debt	2,622	1,874
Commercial paper	4,180	4,243
Bank loans	250	205
Other	3,017	3,044

Bank and other loans short term

	December 31,	
	10,069	9,366

	Weighted average interest rate at December 31, 2004	2003
	(%)	
Commercial paper	2	1
Bank loans and other borrowings	2	2
US Industrial Revenue/Municipal bonds	2	1

Note 31 Accounts payable and accrued liabilities

	December 31, 2004		December 31, 2003	
	Within 1 year	After 1 year	Within 1 year	After 1 year
	($ million)			
Trade payables	28,340		20,858	
Other accounts payable and accrued liabilities:				
Joint ventures	137		126	
Associated undertakings	364	5	322	4
Production taxes	517	1,520	421	1,544
Taxation on profits	4,131		3,441	
Social security	122		96	
Accruals and deferred income	9,569	1,000	6,411	1,321
Dividends	1,822		1,495	
Other	9,339	1,980	7,958	3,161
	26,001	4,505	20,270	6,030

Note 32 Other provisions

	Decommissioning	Environmental	Other	Total
	($ million)			
At January 1, 2004	4,720	2,298	1,797	8,815
Prior year adjustment change in accounting policy			(216)	(216)
As restated	4,720	2,298	1,581	8,599
Exchange adjustments	213	21	25	259
New provisions	294	588	298	1,180
Write-back of unused provisions		(151)	(64)	(215)
Unwinding of discount	118	55	23	196
Change in discount rate	434	40	1	475
Utilized/deleted	(199)	(393)	(294)	(886)
At December 31, 2004	5,580	2,458	1,570	9,608

The Group makes full provision for the future cost of decommissioning oil and natural gas production facilities and related pipelines on a discounted basis on the installation of those facilities. At December 31, 2004, the provision for the costs of decommissioning these production facilities and pipelines at the end of their economic lives was $5,580 million (2003 $4,720 million). The provision has been estimated using existing technology, at current prices and discounted using a real discount rate of 2.0% (2003 2.5%). 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 and timing of incurring these costs. The estimated aggregate costs used in assessing the provision were $8,247 million.

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, 2004 was $2,458 million (2003 $2,298 million). The provision has been estimated using existing technology, at current prices and discounted using a real discount rate of 2.0% (2003 2.5%). The majority of these costs are expected to be incurred over the next 10 years. 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 liability. The estimated aggregate costs used in assessing the provision were $2,620 million.

The Group also holds provisions for expected rental shortfalls on surplus properties, litigation 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 either a nominal discount rate of 4.5% (2003 4.5%) or a real discount rate of 2.0% (2003 2.5%), as appropriate.

Note 33 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, cash balance and other types of schemes with committed pension payments). 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' 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. The pension plans in the UK and US are reviewed annually by the independent actuaries and subject to a formal actuarial valuation at least every three years. The date of the latest actuarial valuation for the UK and US plans was January 1, 2003 and January 1, 2004 respectively. The date of the most recent actuarial reviews was December 31, 2004.

During 2004, contributions of $249 million ($258 million) and $30 million ($2,189 million) were made to the UK plans and US plans respectively. In addition, contributions of $116 million ($86 million) were made to other funded defined benefit plans. The aggregate level of contributions in 2005 is expected to be approximately $600 million.

The pension assumptions for the principal plans are set out below. The assumptions used to evaluate accrued pension benefits at December 31 in any year are used to determine pension expense for the following year, that is, the assumptions at December 31, 2004 are used to determine the pension liabilities at that date and the pension cost for 2005.

	At December 31,		
	2004	2003	2002
	(%)		
UK plans:			
Discount rate for plan liabilities	5.25	5.5	5.75
Rate of increase in salaries	4.0	4.0	4.0
Rate of increase for pensions in payment	2.5	2.5	2.5
Rate of increase in deferred pensions	2.5	2.5	2.5
Inflation	2.5	2.5	2.5
US plans:			
Discount rate for plan liabilities	5.75	6.0	6.75
Rate of increase in salaries	4.0	4.0	4.0
Rate of increase for pensions in payment	nil	nil	nil
Rate of increase in deferred pensions	nil	nil	nil
Inflation	2.5	2.5	2.5
Other plans:			
Discount rate for plan liabilities	5.0	5.5	5.75
Rate of increase in salaries	4.0	4.0	4.0
Rate of increase for pensions in payment	2.5	2.5	2.5
Rate of increase in deferred pensions	2.5	2.5	2.5
Inflation	2.5	2.5	2.5

The assumed rate of investment return and discount rate have a significant effect on the amounts reported. A one percentage point change in these assumptions for the Group's plans would have the following effects:

	1-Percentage point increase	1-Percentage point decrease
	($ million)	
Investment return:		
Effect on pension expense in 2005	(312)	314
Discount rate:		
Effect on pension expense in 2005	(87)	88
Effect on pension obligation at December 31, 2004	(4,508)	5,575

The expected long-term rates of return and market values of the various categories of asset held by the significant defined benefit plans at December 31, are set out below.

	At December 31,					
	2004		2003		2002	
	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)
UK plans:						
Equities	7.5	17,329	7.5	14,642	7.5	10,815
Bonds	4.5	2,859	4.75	2,477	5.0	2,263
Property	6.5	1,660	6.5	1,336	6.5	1,352
Cash	4.0	459	4.0	769	4.0	708
	7.0	22,307	7.0	19,224	7.0	15,138
Present value of plan liabilities		20,399		17,766		14,822
Surplus in the plans		1,908		1,458		316
Deferred tax		(572)		(437)		(95)
At December 31		1,336		1,021		221
US plans:						
Equities	8.5	6,043	8.5	5,650	8.5	3,371
Bonds	4.75	1,057	4.75	1,018	5.5	720
Property	8.0	28	8.0	41	8.0	49
Cash	3.0	55	3.5	148	3.5	66
	8.0	7,183	8.0	6,857	8.0	4,206
Present value of plan liabilities		7,826		7,709		6,765
Deficit in the plans		(643)		(852)		(2,559)
Deferred tax		231		307		921
At December 31		(412)		(545)		(1,638)
Other plans:						
Equities	8.0	933	7.5	686	7.5	515
Bonds	4.25	857	4.75	737	5.0	672
Property	5.25	114	6.5	129	6.5	101
Cash	3.5	288	4.0	187	4.0	159
	6.0	2,192	6.0	1,739	6.0	1,447
Present value of plan liabilities		8,044		6,376		5,141
Deficit in the plans		(5,852)		(4,637)		(3,694)
Deferred tax		540		302		249
At December 31		(5,312)		(4,335)		(3,445)

	At December 31,		

	At December 31, 2004		
	Surplus	Deficit	Net
	($ million)		
UK plans	1,465	(129)	1,336
US plans		(412)	(412)
Other plans	10	(5,322)	(5,312)
	1,475	(5,863)	(4,388)

	At December 31, 2003		
	Surplus	Deficit	Net
	($ million)		
UK plans	1,093	(72)	1,021
US plans		(545)	(545)
Other plans	53	(4,388)	(4,335)
	1,146	(5,005)	(3,859)

	At December 31, 2002		
	Surplus	Deficit	Net
	($ million)		
UK plans	348	(127)	221
US plans		(1,638)	(1,638)
Other plans	40	(3,485)	(3,445)
	388	(5,250)	(4,862)

	Year ended December 31, 2004			
	UK	US	Other	Total
	($ million)			
Analysis of the amount charged to operating profit				
Current service cost	363	215	118	696
Past service cost	5		38	43
Settlement, curtailment and special termination benefits	37		27	64
Payments to defined contribution plans		150	12	162
Total operating charge	405	365	195	965
Analysis of the amount credited (charged) to other finance income				
Expected return on pension plan assets	1,351	526	104	1,981
Interest on pension plan liabilities	(981)	(445)	(346)	(1,772)
Other finance income (expense)	370	81	(242)	209
Analysis of the amount recognized in the statement of total recognized gains and losses				
Actual return less expected return on pension plan assets.	818	379	152	1,349
Experience gains and losses arising on the plan liabilities	83	(22)	(562)	(501)
Change in assumptions underlying the present value of the plan liabilities	(795)	(108)	(366)	(1,269)
Actuarial gain (loss) recognized in statement of total recognized gains and losses	106	249	(776)	(421)
Movement in surplus (deficit) during the year				
Surplus (deficit) in plans at January 1, 2004	1,458	(852)	(4,637)	(4,031)
Movement in year:				
Current service cost	(363)	(215)	(118)	(696)
Past service cost	(5)		(38)	(43)
Settlement, curtailment and special termination benefits	(37)		(27)	(64)
Acquisitions			(3)	(3)
Disposals		32	59	91
Other finance income (expense)	370	81	(242)	209
Actuarial gain (loss)	106	249	(776)	(421)
Employers' contributions	249	62	401	712
Exchange adjustments	130		(471)	(341)
Surplus (deficit) in plans at December 31, 2004	1,908	(643)	(5,852)	(4,587)

	Year ended December 31, 2003			
	UK	US	Other	Total
	($ million)			
Analysis of the amount charged to operating profit				
Current service cost	290	177	116	583
Past service cost		14		14
Settlement, curtailment and special termination benefits		(11)	87	76
Payments to defined contribution plans		134	36	170
Total operating charge	290	314	239	843
Analysis of the amount credited (charged) to other finance income				
Expected return on pension plan assets	1,053	351	94	1,498
Interest on pension plan liabilities	(848)	(432)	(301)	(1,581)
Other finance income (expense)	205	(81)	(207)	(83)
Analysis of the amount recognized in the statement of total recognized gains and losses				
Actual return less expected return on pension plan assets.	1,639	749	2	2,390
Experience gains and losses arising on the plan liabilities	641	30	135	806
Change in assumptions underlying the present value of the plan liabilities	(1,437)	(1,030)	(279)	(2,746)
Actuarial gain (loss) recognized in statement of total recognized gains and losses	843	(251)	(142)	450
Movement in surplus (deficit) during the year				
Surplus (deficit) in plans at January 1, 2003	316	(2,559)	(3,694)	(5,937)
Movement in year:				
Current service cost	(290)	(177)	(116)	(583)
Past service cost		(14)		(14)
Settlement, curtailment and special termination benefits		11	(87)	(76)
Acquisitions			1	1
Other finance income (expense)	205	(81)	(207)	(83)
Actuarial gain (loss)	843	(251)	(142)	450
Employers' contributions	258	2,219	295	2,772
Exchange adjustments	126		(687)	(561)
Surplus (deficit) in plans at December 31, 2003	1,458	(852)	(4,637)	(4,031)

	Year ended December 31, 2002			
	UK	US	Other	Total
	($ million)			
Analysis of the amount charged to operating profit				
Current service cost	278	150	81	509
Past service cost		38	4	42
Settlement, curtailment and special termination benefits		75	(84)	(9)
Payments to defined contribution plans		126	27	153
Total operating charge	278	389	28	695
Analysis of the amount credited (charged) to other finance income				
Expected return on pension plan assets	1,204	530	72	1,806
Interest on pension plan liabilities	(773)	(421)	(258)	(1,452)
Other finance income (expense)	431	109	(186)	354
Analysis of the amount recognized in the statement of total recognized gains and losses				
Actual return less expected return on pension plan assets	(3,874)	(1,305)	(137)	(5,316)
Experience gains and losses arising on the plan liabilities	212	(290)	90	12
Change in assumptions underlying the present value of the plan liabilities	(480)	(343)	(440)	(1,263)
Actuarial loss recognized in statement of total recognized gains and losses	(4,142)	(1,938)	(487)	(6,567)
Movement in surplus (deficit) during the year				
Surplus (deficit) in plans at January 1, 2002	4,134	(521)	(1,937)	1,676
Movement in year:				
Current service cost	(278)	(150)	(81)	(509)
Past service cost		(38)	(4)	(42)
Settlement, curtailment and special termination benefits		(75)	84	9
Acquisitions		(14)	(1,036)	(1,050)
Other finance income (expense)	431	109	(186)	354
Actuarial loss	(4,142)	(1,938)	(487)	(6,567)
Employers' contributions	3	68	251	322
Exchange adjustments	168		(298)	(130)
Surplus (deficit) in plans at December 31, 2002	316	(2,559)	(3,694)	(5,937)

	At December 31, 2004			
	UK	US	Other	Total
History of experience gains and losses				
Difference between the expected and actual return on plan assets:				
Amount ($ million)	818	379	152	1,349
Percentage of plan assets	4%	5%	7%	4%
Experience gains and losses on plan liabilities:				
Amount ($ million)	83	(22)	(562)	(501)
Percentage of the present value of the plan liabilities	0%	0%	(7)%	(1)%
Total amount recognized in statement of total recognized gains and losses:				
Amount ($ million)	106	249	(776)	(421)
Percentage of the present value of the plan liabilities	1%	3%	(10)%	(1)%

	At December 31, 2003			
	UK	US	Other	Total
History of experience gains and losses				
Difference between the expected and actual return on plan assets:				
Amount ($ million)	1,639	749	2	2,390
Percentage of plan assets	9%	11%	0%	9%
Experience gains and losses on plan liabilities:				
Amount ($ million)	641	30	135	806
Percentage of the present value of the plan liabilities	4%	0%	2%	3%
Total amount recognized in statement of total recognized gains and losses:				
Amount ($ million)	843	(251)	(142)	450
Percentage of the present value of the plan liabilities	5%	(3)%	(2)%	1%

	At December 31, 2002			
	UK	US	Other	Total
History of experience gains and losses				
Difference between the expected and actual return on plan assets:				
Amount ($ million)	(3,874)	(1,305)	(137)	(5,316)
Percentage of plan assets	(26)%	(31)%	(9)%	(26)%
Experience gains and losses on plan liabilities:				
Amount ($ million)	212	(290)	90	12
Percentage of the present value of the plan liabilities	1%	(4)%	2%	0%
Total amount recognized in statement of total recognized gains and losses:				
Amount ($ million)	(4,142)	(1,938)	(487)	(6,567)
Percentage of the present value of the plan liabilities	(28)%	(29)%	(9)%	(25)%

Further information in respect of the Group's principal defined benefit pension plans required under FASB Statement of Financial Accounting Standards No. 132 (R) 'Employers' Disclosures about Pensions and Other Postretirement Benefits' is set out below.

Pension plan assets are generally held in trusts. The primary objective of the trusts is to accumulate pools of assets sufficient to meet the obligation of the various plans. The assets of the trusts are invested in a manner consistent with fiduciary obligations and principles that reflect current practices in portfolio management.

A significant proportion of the assets are held in equities owing to a higher expected level of return over the long term with an acceptable level of risk. In order to provide reasonable assurance that no single security or type of security has an unwarranted impact on the total portfolio, the investment portfolios are highly diversified. The long-term asset allocation policy for the major plans is as follows:

Asset category	**Policy range**
	(%)
Total equity	55 - 85
Fixed income/cash	15 - 35
Property/real estate	0 - 10

Some of the Group's pension funds use derivatives to manage their asset mix and the level of risk. Direct investment of trust assets in either securities or real property of the Company or any affiliate is generally prohibited.

Return on asset assumptions reflect on the Company's expectations built up by asset class and by country. The Company's expectation is derived from a combination of historical returns over the long term and the forecasts of market professionals.

	At December 31,			
	2004	**2003**	**2002**	**2001**
	(%)			
Main assumptions for the principal plans				
UK plans:				
Discount rate	5.25	5.5	5.75	6.0
Expected return on plan assets	7.0	7.0	7.0	6.0
Rate of increase in salaries	4.0	4.0	4.0	4.5
US plans:				
Discount rate	5.75	6.0	6.75	7.25
Expected return on plan assets	8.0	8.0	8.0	10.0
Rate of increase in salaries	4.0	4.0	4.0	4.0
Other plans:				
Discount rate	5.0	5.5	5.75	6.25
Expected return on plan assets	6.0	6.0	6.0	6.5
Rate of increase in salaries	4.0	4.0	4.0	3.25

	Years ended December 31,		
	2004	2003	2002
	($ million)		
Pension expense			
Principal plans:			
Service cost benefits earned during year	688	583	509
Interest cost on projected benefit obligation	1,776	1,581	1,452
Expected return on plan assets	(2,159)	(1,882)	(1,787)
Amortization of transition asset	9	(68)	(64)
Recognized net actuarial gain	304	(8)	(206)
Recognized prior service cost	134	87	77
Curtailment and settlement (gains) losses	(2)	4	(46)
Special termination benefits	60	92	76
	810	389	11
Defined contribution plans	162	170	153
Total pension expense	972	559	164

Estimated future benefit payments

The expected benefit payments, which reflect expected future service, as appropriate, through 2014 are as follows:

	UK	US	Other
	($ million)		
2005	963	552	455
2006	994	568	451
2007	1,030	590	453
2008	1,071	606	450
2009	1,113	620	445
2010-2014	6,105	3,184	2,041

	UK		US		Other	
	2004	2003	2004	2003	2004	2003
			($ million)			
Benefit obligation at January 1	17,766	14,822	7,709	6,765	6,376	5,141
Disposals			(97)		(59)	
Service cost	364	290	213	177	118	116
Interest cost	981	848	446	432	346	301
Plan amendments	5			14	38	
Settlement, curtailment and special termination benefits	37			(11)	27	87
Actuarial (gain) loss	692	796	133	1,000	928	144
Acquisitions					3	1
Plan participants' contributions	33	33			4	2
Benefit payments	(943)	(761)	(578)	(668)	(383)	(325)
Exchange adjustment	1,464	1,738			646	909
Benefit obligation at December 31	20,399	17,766	7,826	7,709	8,044	6,376
Fair value of plan assets at January 1	19,224	15,138	6,857	4,206	1,739	1,447
Disposals			(62)			
Actual return on plan assets	2,149	2,692	904	1,100	256	96
Acquisitions						2
Plan participants' contributions	33	33			4	2
Employers' contributions	249	258	62	2,219	401	295
Benefit payments	(943)	(761)	(578)	(668)	(383)	(325)
Exchange adjustment	1,595	1,864			175	222
Fair value of plan assets at December 31	22,307	19,224	7,183	6,857	2,192	1,739
Funded status	1,908	1,458	(643)	(852)	(5,852)	(4,637)
Unrecognized transition (asset) obligation					29	37
Unrecognized net actuarial (gain) loss	1,681	1,532	3,442	3,918	1,358	634
Unrecognized prior service cost	640	680	76	78	10	12
Net amount recognized	4,229	3,670	2,875	3,144	(4,455)	(3,954)
Prepaid benefit cost (accrued benefit liability)	3,714	3,670	2,699	2,937	(5,206)	(4,225)
Intangible asset			13	14	26	29
Accumulated other comprehensive income	515		163	193	725	242
	4,229	3,670	2,875	3,144	(4,455)	(3,954)

Note 34 Other postretirement benefits

Certain Group companies in the US 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. 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, 2004 and the date of the most recent actuarial review was December 31, 2004.

At December 31, 2004 the independent actuaries have reassessed the obligation for postretirement benefits at $3,676 million ($4,143 million at December 31, 2003). The discount rate used to assess the obligation at December 31, 2004 of the plans was 5.75% (6.0% at December 31, 2003).

Assumed future healthcare cost trend rate

	Years ended December 31,				
	2005	**2006**	**2007**	**2008**	**2009 and subsequent years**
Beneficiaries aged under 65	9%	8%	7%	6%	5%
Beneficiaries aged over 65	12%	10%	8%	7%	6%

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:

	1-Percentage point increase	**1-Percentage point decrease**
	($ million)	
Effect on postretirement benefit expense in 2005	39	(31)
Effect on postretirement obligation at December 31, 2004	458	(373)

BP's postretirement medical plans in the US provide prescription drug coverage for Medicare-eligible retired employees. The Group's obligation for other postretirement benefits at December 31, 2004 reflects the effects of the recent US Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act). The provisions of the Act provide for a federal subsidy for plans that provide prescription drug benefits and meet certain qualifications, and alternatively would allow prescription drug plan sponsors to coordinate with the Medicare benefit. BP reflected the impact of the legislation by reducing its actuarially determined obligation for postretirement benefits at December 31, 2004 and will reduce the net cost for postretirement benefits in subsequent periods. The reduction in liability was reflected in the 2004 results as an actuarial gain (assumption change). The expected long-term rates of return and market values of the various categories of assets held by the plans at December 31, are set out below.

	At December 31,			
	2004		2003	
	Expected long-term rate of return	Market value	Expected long-term rate of return	Market value
	(%)	($ million)	(%)	($ million)
US plans				
Equities	8.5	21	8.5	24
Bonds	4.75	9	4.75	9
	7.25	30	8.0	33
Present value of plan liabilities		3,676		4,143
Other postretirement benefit liability before deferred tax		(3,646)		(4,110)
Deferred tax		1,520		1,480
		(2,126)		(2,630)

	At December 31,		
	2004	2003	2002
	($ million)		
Analysis of the amount charged to operating profit			
Current service cost	61	54	37
Past service cost	(4)	14	
Settlement, curtailment and special termination benefits		(669)	(78)
Total operating charge (income)	57	(601)	(41)
Analysis of the amount charged to other finance costs			
Expected return on plan assets	2	2	4
Interest on plan liabilities	(240)	(259)	(219)
Other finance expense	(238)	(257)	(215)

At December 31,

Analysis of the amount recognized in the statement of total recognized gains and losses			
Actual return less expected return on plan assets		2	(8)
Experience gains and losses arising on the plan liabilities	33	67	(89)
Change in assumptions underlying the present value of the plan liabilities	495	(443)	(1,165)
Actuarial gain (loss) recognized in statement of total recognized gains and losses	528	(374)	(1,262)
Movement in deficit during the year			
Deficit in plans at January 1	(4,110)	(4,293)	(3,039)
Movement in year:			
Current service cost	(61)	(54)	(37)
Past service cost	4	(14)	
Settlement, curtailment and special termination benefits		669	78
Acquisitions and disposals	18		(36)
Other finance expense	(238)	(257)	(215)
Employers' contributions	213	213	218
Actuarial gain (loss)	528	(374)	(1,262)
Deficit in plans at December 31	(3,646)	(4,110)	(4,293)

	At December 31,	
	2004	**2003**
History of experience gains and losses		
Difference between the expected and actual return on plan assets:		
Amount ($ million)		2
Percentage of plan assets	0%	6%
Experience gains and losses on plan liabilities:		
Amount ($ million)	33	67
Percentage of the present value of the plan liabilities	1%	2%
Total amount recognized in statement of total recognized gains and losses:		
Amount ($ million)	528	(374)
Percentage of the present value of the plan liabilities	14%	(9)%

Further information presented in compliance with the requirements of FASB Statement of Financial Accounting Standards No. 132 (R) 'Employers' Disclosures about Pensions and Other Postretirement Benefits' is set out below.

	2004	2003
	($ million)	
Benefit obligation at January 1	4,143	4,326
Disposals	(18)	
Service cost	61	54
Interest cost	240	259
Plan amendments	(4)	14
Settlement, curtailment and special termination benefits		(669)
Actuarial (gain) loss	(528)	376
Benefit payments	(218)	(217)
Benefit obligation at December 31	3,676	4,143
Fair value of plan assets at January 1	33	33
Actual return on plan assets	2	4
Employers' contributions	213	213
Benefit payments	(218)	(217)
Fair value of plan assets at December 31	30	33
Funded status	(3,646)	(4,110)
Unrecognized net actuarial loss	1,149	1,834
Unrecognized prior service cost	(579)	(648)
Provision for postretirement benefits	(3,076)	(2,924)

Estimated future benefit payments

The expected benefit payments, which reflect expected future service, as appropriate, through 2014 are as follows:

	US
	($ million)
2005	251
2006	235
2007	238
2008	237
2009	239
2010-2014	1,236

Note 35 Capital and reserves

	Share capital	Paid in surplus	Merger reserve	Other reserves	Shares held by ESOP trusts	Retained earnings	Total
				($ million)			
At January 1, 2004	5,552	4,480	27,077	129		38,700	75,938
Prior year adjustment change in accounting policy					(96)	(5,247)	(5,343)
As restated	5,552	4,480	27,077	129	(96)	33,453	70,595
Currency translation differences (net of tax)					(7)	2,143	2,136
Actuarial gain (net of tax)						203	203
Unrealized gain on acquistion of further investment in equity-accounted investments						94	94
Employee share schemes	16	311					327
Atlantic Richfield	7	153	85	(85)			160
Issue of ordinary share capital for TNK-BP	35	1,215					1,250
Purchase of shares by ESOP trusts					(147)		(147)
Charge for long-term performance plans and employee share schemes						226	226
Release of shares by ESOP trusts					168	(168)	
Repurchase of ordinary share capital	(207)	207				(7,548)	(7,548)
Profit for the year						15,731	15,731
Dividends						(6,371)	(6,371)
At December 31, 2004	5,403	6,366	27,162	44	(82)	37,763	76,656

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 62,224,092 ordinary shares were issued under the BP, Amoco and Burmah Castrol employee share schemes.

Atlantic Richfield. 29,288,178 ordinary shares were issued in respect of Atlantic Richfield employee share option schemes.

Issue of ordinary share capital for TNK-BP. The Company issued 139,095,888 ordinary shares as the first tranche of deferred consideration for the acquisition of the investment in TNK-BP.

Repurchase of ordinary share capital. The Company purchased for cancellation 827,240,360 ordinary shares for a total consideration of $7,548 million.

Note 36 Retained earnings

Retained earnings of $37,763 million ($33,453 million at December 31, 2003) include the following amounts, the distribution of which is limited by statutory or other restrictions:

	December 31,	
	2004	2003
	($ million)	
Parent company	25,026	24,107
Subsidiary undertakings	2,927	2,115
Joint ventures and associated undertakings	441	566
	28,394	26,788

Cumulative net exchange gains (net of tax) of $4,529 million are included in retained earnings ($2,386 million gain at December 31, 2003).

There were no unrealized currency translation differences for the year on long-term borrowings used to finance equity investments in foreign currencies (2003 nil and 2002 nil).

Note 37 Analysis of consolidated statement of cash flows

Reconciliation of profit before interest and tax to net cash inflow from operating activities

	Years ended December 31,		
	2004	**2003**	**2002**
	($ million)		
Profit before interest and tax	25,242	17,954	12,329
Depreciation and amounts provided	12,583	10,940	10,401
Exploration expenditure written off	274	297	385
Net operating charge for pensions and other postretirement benefits, less contributions	(67)	(2,913)	(39)
Share of profits of joint ventures and associated undertakings	(3,574)	(1,438)	(966)
Interest and other income	(325)	(341)	(358)
(Profit) loss on sale of fixed assets and businesses or termination of operations	(815)	(831)	(1,166)
Charge for provisions	671	782	645
Utilization of provisions	(781)	(716)	(847)
(Increase) decrease in inventories	(3,595)	(841)	(1,521)
(Increase) decrease in receivables	(10,920)	(3,042)	(2,367)
Increase (decrease) in payables	9,861	1,847	2,846
Net cash inflow from operating activities	28,554	21,698	19,342

Financing

	Years ended December 31,		
	2004	**2003**	**2002**
	($ million)		
Long-term borrowing	(2,675)	(4,322)	(3,707)
Repayments of long-term borrowing	2,204	3,560	2,369
Short-term borrowing	(3,335)	(4,706)	(9,849)
Repayments of short-term borrowing	3,375	4,708	10,451
	(431)	(760)	(736)
Issue of ordinary share capital for employee share schemes	(487)	(173)	(195)
Purchase of shares by ESOP trusts	147	63	18
Repurchase of ordinary share capital	7,548	1,999	750
Net cash (inflow) outflow	6,777	1,129	(163)

Management of liquid resources

Liquid resources comprise current asset investments, which are principally commercial paper issued by other companies. The net cash outflow from the management of liquid resources was $132 million (2003 $41 million inflow and 2002 $220 million inflow).

Commercial paper

Net movements in commercial paper are included within short-term borrowings or repayment of short-term borrowings as appropriate.

Movement in net debt

	Years ended December 31,							
	2004				2003			
	Finance debt	Cash	Current asset investments	Net debt	Finance debt	Cash	Current asset investments	Net debt
	($ million)							
At January 1	(22,325)	1,947	185	(20,193)	(22,008)	1,520	215	(20,273)
Exchange adjustments	(403)	80	11	(312)	(199)	110	11	(78)
Acquisitions					(15)			(15)
Net cash flow	(431)	(871)	132	(1,170)	(760)	317	(41)	(484)
Debt transferred to TNK-BP					93			93
Exchange of Exchangeable Bonds for Lukoil American Depositary Shares					420			420
Other movements	68			68	144			144
At December 31	(23,091)	1,156	328	(21,607)	(22,325)	1,947	185	(20,193)

Note 38 Employee share plans

Employee share options granted during the year (a)

	2004	2003	2002
	(options thousands)		
Executive Directors' Incentive Plan	2,783	2,728	2,068
BP Share Option Plan	71,750	78,109	66,771
Savings-related schemes	5,861	23,922	9,719
	80,394	104,759	78,558

(a) The exercise prices for BP options granted during the year were £4.22/$7.73 (weighted average price) for Executive Directors' Incentive Plan (2,783,333 options); £4.38/$8.01 (weighted average price) for 71,750,436 options granted under the BP Share Option Plan; and £3.86/$7.06 (5,860,991 options) for savings-related and similar plans.

BP offers most of its employees the opportunity to acquire a shareholding in the Company through savings-related and/or matching share plan arrangements. Such arrangements are now in place in nearly 80 countries. BP also uses long-term performance plans (see Note 39) and the granting of share options as elements of remuneration for executive directors and senior employees.

During 2004, share options were granted to the executive directors under the Executive Directors' Incentive Plan (EDIP). For these options the option exercise price was the market value (as determined in accordance with the plan rules) 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 as well as the underlying health of the business and the competitive market place. Options are not granted in any year unless the criteria for an award of shares under the share element of the EDIP (see Note 39) have been met. Options vest over three years (one-third each after one, two and three years respectively) and have a life of seven years after the grant.

Share options were also granted in 2004 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 plan) employees save on a monthly basis 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.

Under 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 70 other countries.

The Group takes advantage of the exemption granted under Urgent Issues Task Force Abstract No. 17 (revised 2003) 'Employee Share Schemes', whereby no compensation expense need be recognized for the BP ShareSave Plan. BP does not recognize an expense in respect of share options granted to employees under the BP Share Option Plan. If the fair value of options granted in any particular year is estimated and this value amortized over the vesting period of the options, an indication of the cost of granting options to employees can be made. The fair value of each share option granted has been estimated using a Black-Scholes option pricing model with the following assumptions:

	Years ended December 31,		
	2004	**2003**	**2002**
Risk-free interest rate	4.0%	3.5%	4.0%
Expected volatility	22%	30%	26%
Expected life in years	1 to 5	1 to 5	1 to 5
Expected dividend yield	3.75%	4.00%	3.75%
Weighted average fair value of options granted ($)	1.40	1.44	1.64

The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of FASB Statement No. 123, Accounting for Stock-Based Compensation, to share based employee compensation.

	Years ended December 31,		
	2004	**2003**	**2002**
		($ million)	
Profit for the year applicable to ordinary shares, as reported	15,729	10,480	6,793
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(79)	(79)	(90)
Pro forma net income	15,650	10,401	6,703
		(cents)	
Earnings per share			
Basic as reported	72.08	47.27	30.33
Basic pro forma	71.72	46.91	29.93
Diluted as reported	70.79	46.83	30.19
Diluted pro forma	70.43	46.48	29.79

The Company sponsors a number of savings plans covering most US employees. Under these plans, most employees may contribute up to 100% of their salary subject to certain regulatory limits. Most employees are eligible for a dollar-for-dollar Company-matched contribution for the first 7% of eligible pay contributed on a before-tax or after-tax basis, or a combination of both. The precise arrangement may vary in certain business units. Plan participants may invest contributions in more than 200 investment options, including a fund comprised primarily of BP ADSs. The Company's contributions generally vest over a period of three years (0% for years one and two and 100% after completion of three years). Company contributions to savings plans during the year were $138 million (2003 $130 million and 2002 $125 million).

An Employee Share Ownership Plan (ESOP) was established in 1997 to acquire BP shares to satisfy future requirements of certain employee share plans, principally the BP ShareMatch Plan. The ESOP holds the shares for participants during the retention period of the plan. The Company provides funding to the ESOP. Until such time as the Company's own shares held by the ESOP trust vest unconditionally in employees, the amount paid for those shares is deducted in arriving at shareholders' interest (see Note 35 of Notes to Financial Statements). Other assets and liabilities of the ESOP are recognized as assets and liabilities of the Company. The ESOP has waived its rights to dividends.

During 2004, the ESOP released 14,156,047 shares (2003 16,892,853 shares and 2002 15,332,235 shares) for the matching share plans. The cost of shares released for these plans has been charged in these accounts. At December 31, 2004, the ESOP held 2,682,860 shares (at December 31, 2003 7,811,544 shares).

BP had established a Qualifying Employee Share Ownership Trust (QUEST) to support the UK ShareSave plan. During 2002, contributions of $21 million were made by the Company to QUEST which, together with option-holder contributions, were used by the QUEST to subscribe for new ordinary shares at market price. The Company transferred the cost of this contribution directly to retained earnings and the excess of the subscription price over the nominal value has increased the paid in surplus.

At December 31, 2002, all the ordinary shares issued to the QUEST had been transferred to employees exercising options under the UK ShareSave plan. Under new legislation, the QUEST can no longer be used for ShareSave plans after December 31, 2002.

	Years ended December 31,		
	2004	**2003**	**2002**
	(shares thousands)		
Shares issued in respect of options exercised during the year:			
Savings-related schemes	3,163	5,325	10,412
BP, Amoco and Burmah Castrol executive share option plans	59,061	27,564	23,409
	62,224	32,889	33,821

	2004	**2003**	**2002**
Options outstanding at December 31:			
BP options (shares thousands)	470,264	461,886	410,986
Exercise period	2005-2014	2004-2013	2003-2012
Price	£2.04-£6.40	£1.86-£6.40	£1.50-£6.40
Price	\$3.95-\$9.97	\$3.47-\$9.97	\$3.47-\$9.97

The following table summarizes share option transactions under employee share plans.

	Years ended December 31,					
	2004		**2003**		**2002**	
	Number of shares	**Weighted average exercise price**	**Number of shares**	**Weighted average exercise price**	**Number of shares**	**Weighted average exercise price**
		(\$)		(\$)		(\$)
Outstanding at January 1	461,885,881	6.76	410,986,179	6.70	373,857,979	6.20
Reinstated	434,285	7.96	35,876	7.57	24,310	5.08
Granted	80,394,760	7.93	104,758,602	6.22	78,557,576	8.07
Exercised	(62,625,182)	5.18	(32,988,942)	4.11	(34,130,302)	4.20
Cancelled	(9,825,936)	7.30	(20,905,834)	7.05	(7,323,384)	7.59
Outstanding at December 31	470,263,808	7.16	461,885,881	6.76	410,986,179	6.70
Exercisable at December 31	224,627,758		229,198,494		239,241,597	
Available for grant at December 31	966,076,636		1,079,531,345		1,159,841,669	

Options outstanding at December 31, 2004 will be exercisable between 2005 and 2014.

For the share options outstanding and exercisable at December 31, 2004 the exercise price ranges and average remaining lives were:

	Options outstanding			Options exercisable	
	Number of shares	Weighted average remaining life	Weighted average exercise price	Number of shares	Weighted average exercise price
		(years)	($)		($)
Range of exercise prices					
$3.22 - $4.61	24,058,341	0.98	4.41	23,759,435	4.41
$5.02 - $6.49	162,768,929	5.28	5.94	66,597,119	5.58
$6.78 - $8.33	247,090,117	6.62	7.99	121,545,703	8.07
$8.57 - $10.10	36,346,421	6.61	8.82	12,725,501	9.11
	470,263,808	5.87	7.16	224,627,758	7.00

Note 39 Long-term performance plans

During 2004, the Company operated two long-term performance plans: the Executive Directors' Incentive Plan (EDIP) for executive directors and the Long Term Performance Plan (LTPP) for senior employees. Executive directors participated in the LTPP prior to 2002 or to their appointment as an executive director, whichever was the later. 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 2004 in respect of the 2001-2003 LTPP. Further details of the plans are given in Item 6 Directors, Senior Management and Employees Compensation on page 117.

The costs of potential future awards for both the EDIP and LTPP are accrued over the three-year performance periods of each plan. The amount charged in 2004 was $89 million (2003 $94 million and 2002 $51 million). The value of awards under the 2001-2003 LTPP made in 2004 was $42 million (2000-2002 LTPP made in 2003 $35 million and 1999-2001 LTPP made in 2002 $125 million). Employees are able to defer the date of their potential award beyond the end of the performance period. The amount charged in respect of the increase in deferred awards after the expiry of the relevant performance periods was $23 million (2003 $17 million and 2002 $19 million).

Employee Share Ownership Plans (ESOPs) have been established to acquire BP shares to satisfy any awards made to participants under the EDIP 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 and deferred 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, 2004 the ESOPs held 5,938,359 shares (at December 31, 2003, 4,118,835 shares) for potential future awards.

Note 40 Employee costs and numbers

	Years ended December 31, 2004	2003	2002
	($ million)		
Employee costs			
Wages and salaries	7,922	7,142	6,519
Social security costs	667	622	490
Pension and other postretirement benefit costs	1,051	582	515
	9,640	8,346	7,524

	At December 31, 2004	2003	2002
Number of employees			
Exploration and Production	15,650	15,150	16,600
Refining and Marketing (a)	67,250	66,150	72,300
Petrochemicals	12,400	15,950	18,950
Gas, Power and Renewables	4,050	3,750	4,600
Other businesses and corporate	3,550	2,700	2,800
	102,900	103,700	115,250

(a) Includes 27,950 (2003 26,950 and 2002 30,250) service station staff.

	UK	Rest of Europe	USA	Rest of World	Total
Average number of employees					
Year ended December 31, 2004					
Exploration and Production	2,900	650	4,900	6,950	15,400
Refining and Marketing	10,100	18,250	25,900	12,550	66,800
Petrochemicals	2,400	5,750	5,450	1,250	14,850
Gas, Power and Renewables	200	800	1,400	1,550	3,950
Other businesses and corporate	1,550		1,550	100	3,200
	17,150	25,450	39,200	22,400	104,200
Year ended December 31, 2003					
Exploration and Production	3,200	750	5,000	6,900	15,850
Refining and Marketing	9,900	19,600	26,950	12,300	68,750
Petrochemicals	2,650	5,950	6,250	1,800	16,650

	UK	Rest of Europe	USA	Rest of World	Total
Gas, Power and Renewables	250	950	1,450	1,550	4,200
Other businesses and corporate	1,250		1,350	100	2,700
	17,250	27,250	41,000	22,650	108,150

	UK	Rest of Europe	USA	Rest of World	Total
Year ended December 31, 2002					
Exploration and Production	3,750	800	5,350	6,800	16,700
Refining and Marketing	10,200	20,650	28,650	11,550	71,050
Petrochemicals	3,200	6,300	6,650	5,150	21,300
Gas, Power and Renewables	500	850	1,600	1,550	4,500
Other businesses and corporate	1,250		1,400	100	2,750
	18,900	28,600	43,650	25,150	116,300

Note 41 Directors' remuneration

	Years ended December 31,		
	2004	2003	2002
	($ million)		
Total for all directors			
Emoluments	19	17	14
Ex gratia payment to executive director retiring in 2003		1	
Gains made on the exercise of share options	3	1	
Amounts awarded under incentive schemes	6	4	14

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.

Pension contributions

Six executive directors participated 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. One US executive director participated in the US BP Retirement Accumulation Plan during 2004.

Office facilities for former chairmen and deputy chairmen

It is customary for the Company to make available to former chairmen and deputy chairmen, who were previously employed executives, the use of office and basic secretarial facilities following their retirement. The cost involved in doing so is not significant.

Note 42 Joint ventures and associated undertakings

The significant joint ventures and associated undertakings of the BP Group at December 31, 2004 are shown in Note 45.

The principal joint venture is the TNK-BP joint venture. Summarized financial information for the Group's share of joint ventures is shown below.

	TNK-BP	Other	2004 Total	TNK-BP	Other	2003 Total	2002 Total
			($ million)				
Turnover	7,839	1,951	9,790	1,864	1,610	3,474	1,465
Profit for the year before tax	2,320	455	2,775	475	360	835	288
Taxation	752	298	1,050	83	61	144	75
Profit for the year after tax	1,568	157	1,725	392	299	691	213
Fixed assets	9,955	4,556	14,511	8,389	3,558	11,947	2,771
Current assets	2,565	1,168	3,733	1,950	1,368	3,318	803
	12,520	5,724	18,244	10,339	4,926	15,265	3,574
Current liabilities	1,959	686	2,645	1,575	752	2,327	284
Non current liabilities	1,851	1,820	3,671	1,350	1,434	2,784	514
	8,710	3,218	11,928	7,414	2,740	10,154	2,776
Minority shareholders' interest	542		542	365		365	
	8,168	3,218	11,386	7,049	2,740	9,789	2,776

The joint venture TNK-BP was created on August 29, 2003. See Note 19 for further information. TNK-BP in which BP holds a 50% interest, is an integrated oil company operating; inter alia, in Russia.

The preliminary fair values attributed to the assets and liabilities of TNK-BP in 2003 have been revised in 2004 as permitted by Financial Reporting Standard No. 7 'Fair Values in Acquisition Accounting'.

The results for TNK-BP for 2004 have been estimated. Any difference between the estimated and actual results for this period will be included in the results for 2005. The adjustment included in 2004 in respect of 2003 was a charge of $36 million.

BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America became subsidiary undertakings with effect from November 2, 2004.

Transactions between the significant joint ventures and associated undertakings and the Group are summarized below.

Sales to joint ventures and associated undertakings

		2004		2003		2002
	Product	**Sales**	**Amount receivable at December 31**	**Sales**	**Amount receivable at December 31**	**Sales**
		($ million)		($ million)		($ million)
Joint ventures						
BP Solvay Polyethylene Europe (a)	Chemicals feedstocks	230		259	33	308
Pan American Energy	Crude oil	118	4	171	5	124
Watson Cogeneration	Natural gas	214	10	73	6	118
Associated undertakings						
BP Solvay Polyethylene North America (a)	Chemicals feedstocks	217		241	17	143
China American Petrochemical Co.	Chemicals feedstocks	385	81	240	67	117
Ruhrgas (b)	Natural gas					98
Samsung Petrochemical Co.	Chemicals feedstock	62	8	55	10	35

Purchases from joint ventures and associated undertakings

	Product	2004 Purchases	2004 Amount payable at December 31	2003 Purchases	2003 Amount payable at December 31	2002 Purchases
		($ million)		($ million)		($ million)
Joint ventures						
BP Solvay Polyethylene Europe (a)	Chemicals feedstocks			18	14	
Pan American Energy	Crude oil	481	43	381	48	200
TNK-BP (c)	Crude oil and oil products	1,809	80	349	52	
Watson Cogeneration	Electricity and steam	149	14	248	12	94
Associated undertakings						
Abu Dhabi Marine Areas	Crude oil	866	91	661	61	504
Abu Dhabi Petroleum Co.	Crude oil	1,547	145	1,122	118	759
BP Solvay Polyethylene North America (a)	Chemicals feedstocks	9		11	1	7
China American Petrochemical Co.	Petrochemicals	455	111	197	83	77
Ruhrgas (b)	Natural gas					5
Samsung Petrochemical Co.	Chemicals feedstocks	290	17	187	38	114

(a) The BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America sales and purchases shown above relate to the period to November 2, 2004.

(b) The Ruhrgas sales and purchases shown above relate to the period prior to its disposal on July 31, 2002.

(c) The TNK-BP purchases shown above relate to the period from August 29, 2003.

Note 43 Contingent liabilities

There were contingent liabilities at December 31, 2004 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 Atlantic Richfield Company (Atlantic Richfield). 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, Atlantic Richfield, a current subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property caused by lead pigment in paint. The majority of the lawsuits have been abandoned or dismissed as against Atlantic Richfield. Atlantic Richfield (and in one case two of its affiliates) is named in these lawsuits as alleged successor to International Smelting & 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 lawsuit against Atlantic Richfield has been settled or tried to conclusion. The amounts claimed and, if such suits were successful, the costs of implementing the remedies sought in the various cases could be substantial. While it is not possible to predict the outcome of these legal actions, Atlantic Richfield believes that it has valid defences and it intends to defend such actions vigorously and thus the incurring of a liability by Atlantic Richfield is remote. 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 national 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 or 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.

The parent company has issued guarantees under which amounts outstanding at December 31, 2004 were $21,106 million (at December 31, 2003 $20,903 million), including $21,050 million (at December 31, 2003 $20,847 million) in respect of borrowings by its subsidiary undertakings and

$56 million (at December 31, 2003 $56 million) in respect of liabilities of other third parties. In addition, other Group companies have issued guarantees under which amounts outstanding at December 31, 2004 were $1,281 million (at December 31, 2003 $635 million) in respect of borrowings of joint ventures and associated undertakings and $650 million (at December 31, 2003 $304 million) in respect of liabilities of other third parties.

Note 44 Capital commitments

Authorized future capital expenditure by Group companies for which contracts had been placed at December 31, 2004 amounted to $6,765 million (at December 31, 2003 $6,420 million).

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. These figures represent 100% of the Income Statements and Balance Sheets of the joint ventures and associated undertakings, not BP's ownership interest.

	Years ended December 31,		
	2004	2003	2002
	($ million)		
Sales and other operating revenue	38,303	21,479	22,457
Gross profit	9,002	4,816	4,180
Profit for the year	5,413	2,597	2,049

	December 31,	
	2004	2003
	($ million)	
Fixed assets	44,695	37,095
Current assets	13,649	11,972
	58,344	49,067
Current liabilities	(11,765)	(10,761)
Noncurrent liabilities	(12,552)	(9,813)
Net assets	34,027	28,493

The more important joint ventures and associated undertakings of the Group at December 31, 2004 and the percentage of ordinary share capital owned or joint venture interest (to nearest whole number) are:

	%	Country of incorporation	Principal activities
Associated undertakings			
Abu Dhabi			
Abu Dhabi Marine Areas	37	England	Crude oil production
Abu Dhabi Petroleum Co	24	England	Crude oil production
Azerbaijan			
The Baku-Tbilisi-Ceyhan Pipeline Co	30	Cayman Islands	Pipelines
Korea			
Samsung Petrochemical Co.	47	England	Petrochemicals
Taiwan			
China American Petrochemical Co.	61	Taiwan	Petrochemicals

	%	Country of incorporation or registration	Principal activities
Joint ventures			
CaTO Finance V Limited Partnership	50	England	Finance
Lukarco	46	Netherlands	Exploration and production, pipelines
Pan American Energy	60	USA	Exploration and Production
Shanghai Secco Petrochemical Co	50	China	Petrochemicals
TNK-BP	50	British Virgin Islands	Integrated oil operations
Unimar LLC	50	USA	Exploration and Production
Watson Cogeneration	51	USA	Power generation

Note 46 New accounting standards

Comparative information for 2003 and 2002 has been restated to reflect the changes described below.

New accounting standard for pensions and other postretirement benefits

With effect from January 1, 2004, BP has adopted Financial Reporting Standard No. 17 'Retirement Benefits' (FRS 17). 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. This contrasts with Statement of Standard Accounting Practice No. 24 'Accounting for Pension Costs', which required the cost of providing pensions to be recognized on a systematic and rational basis over the period during which the employer benefited from the employee's services. The difference between the amount charged in the income statement and the amount paid as contributions into the pension fund was shown as a prepayment or provision on the balance sheet.

This change in accounting policy has resulted in a prior year adjustment. Shareholders' interest at January 1, 2002 has been reduced by $132 million, the profit for the year ended December 31, 2002 decreased by $50 million and the profit for the year ended December 31, 2003 increased by $215 million. Profit for the current year has been increased by approximately $301 million as a result of the change in accounting policy.

Accounting for Employee Share Ownership Plans

With effect from January 1, 2004, BP has adopted Urgent Issues Task Force Abstract No. 38 'Accounting for Employee Share Ownership Plan (ESOP) Trusts'. This abstract requires that BP shares held by the Group for the purposes of Employee Share Ownership Plans (ESOPs) are deducted from equity on the balance sheet. Such shares were previously classified as fixed asset investments. In addition, accruals for awards under the Long Term Performance Plan have also been included in reserves.

This change in accounting policy has resulted in a prior year adjustment. Shareholders' interest at January 1, 2002 has been decreased by $18 million. The impact of the change in accounting policy on profit for the years ended December 31, 2002, 2003 and 2004 is not significant.

	Years ended December 31,			
	2003		2002	
	Restated	Reported	Restated	Reported
	($ million)			
Group income statement				
Turnover	236,045	236,045	180,186	180,186
Less: joint ventures	3,474	3,474	1,465	1,465
Group turnover	232,571	232,571	178,721	178,721
Cost of sales	201,335	202,029	154,615	154,401
Production taxes	1,723	1,723	1,274	1,274
Gross profit	29,513	28,819	22,832	23,046
Distribution and administration expenses	14,072	14,072	12,632	12,632
Exploration expense	542	542	644	644
	14,899	14,205	9,556	9,770
Other income	786	786	641	641
Group operating profit	15,685	14,991	10,197	10,411
Share of profits of joint ventures	924	924	347	347
Share of profits of associated undertakings	514	514	617	617
Total operating profit	17,123	16,429	11,161	11,375
Profit (loss) on sale of businesses or termination of operations	(28)	(28)	(33)	(33)
Profit (loss) on sale of fixed assets	859	859	1,201	1,201
Profit before interest and tax	17,954	17,260	12,329	12,543
Interest expense	644	851	1,067	1,279
Other finance expense	547		73	
Profit before taxation	16,763	16,409	11,189	11,264
Taxation	6,111	5,972	4,317	4,342
Profit after taxation	10,652	10,437	6,872	6,922
Minority shareholders' interest	170	170	77	77
Profit for the year	10,482	10,267	6,795	6,845
Distribution to shareholders	5,753	5,753	5,375	5,375
Retained profit for the year	4,729	4,514	1,420	1,470
Earnings per ordinary share cents				
Basic	47.27	46.30	30.33	30.55
Diluted	46.83	45.87	30.19	30.41

	Restated	Reported
	($ million)	
Group balance sheet at December 31, 2003		
Fixed assets		
Intangible assets	13,642	13,642
Tangible assets	91,911	91,911
Investments	17,458	17,554
	123,011	123,107
Current assets	47,651	54,465
Current liabilities falling due within one year	50,584	50,584
Net current assets (liabilities)	(2,933)	3,881
Total assets less current liabilities	120,078	126,988
Noncurrent liabilities	18,899	18,959
Provisions for liabilities and charges		
Deferred taxation	14,371	15,273
Other	8,599	15,693
Net assets excluding pension and other postretirement benefit balances	78,209	77,063
Defined benefit pension plan surpluses	1,146	
Defined benefit pension plan deficits	(5,005)	
Other postretirement benefit plan deficit	(2,630)	
Net assets	71,720	77,063
Minority shareholders' interest equity	1,125	1,125
BP shareholders' interest	70,595	75,938

	Years ended December 31,			
	2003		2002	
	Restated	Reported	Restated	Reported
	($ million)			
Statement of total recognized gains and losses				
Profit for the year	10,482	10,267	6,795	6,845
Currency translation differences (net of tax)	3,644	3,841	3,284	3,333
Actuarial gain (loss) (net of tax)	60		(5,370)	
Total recognized gains and losses	14,186	14,108	4,709	10,178
Group cash flow statement				
Net cash inflow from operating activities	21,698	21,698	19,342	19,342
Dividends from joint ventures	131	131	198	198
Dividends from associated undertakings	417	417	368	368
Net cash outflow from servicing of finance and returns on investments	(711)	(711)	(911)	(911)
Tax paid	(4,804)	(4,804)	(3,094)	(3,094)
Net cash outflow for capital expenditure and financial investment	(6,124)	(6,187)	(9,628)	(9,646)
Net cash (outflow) inflow from acquisitions and disposals	(3,548)	(3,548)	(1,337)	(1,337)
Equity dividends paid	(5,654)	(5,654)	(5,264)	(5,264)
Net cash inflow (outflow) before financing	1,405	1,342	(326)	(344)
Financing	1,129	1,066	(163)	(181)
Management of liquid resources	(41)	(41)	(220)	(220)
Increase (decrease) in cash	317	317	57	57
	1,405	1,342	(326)	(344)

	Years ended December 31,			
	2003		2002	
	Restated	Reported	Restated	Reported
	($ million)			
Reconciliation of profit before interest and tax to net cash inflow from operating activities				
Profit before interest and tax	17,954	17,260	12,329	12,543
Depreciation and amounts provided	10,940	10,940	10,401	10,401
Exploration expenditure written off	297	297	385	385
Net operating charge for pensions and other postretirement benefits, less contributions	(2,913)		(39)	
Share of profits of joint ventures and associated undertakings	(1,438)	(1,438)	(966)	(966)
Interest and other income	(341)	(341)	(358)	(358)
(Profit) loss on sale of fixed assets and businesses	(831)	(831)	(1,166)	(1,166)
Charge for provisions	782	1,734	645	1,277
Utilization of provisions	(716)	(1,204)	(847)	(1,427)
(Increase) decrease in inventories	(841)	(841)	(1,521)	(1,521)
(Increase) decrease in receivables	(3,042)	(5,628)	(2,367)	(2,672)
Increase (decrease) in payables	1,847	1,750	2,846	2,846
Net cash inflow from operating activities	21,698	21,698	19,342	19,342

Note 47 Transfer of natural gas liquids activities

With effect from January 1, 2004, natural gas liquids activities were transferred from Exploration and Production to Gas, Power and Renewables. The adjustments between these two segments for 2003 and 2002 are set out below.

	2003	2002
	($ million)	
Group operating profit	106	68
Share of profits of joint ventures		
Share of profits of associated undertakings		
Total operating profit	106	68
Exceptional items		
Profit before interest and tax	106	68
Capital expenditure and acquisitions	82	40
Operating capital employed	389	322
Tangible fixed assets	289	289
Number of employees		
Year end	200	200
Average	200	200

Note 48 Oil and natural gas exploration and production activities(a)

Capitalized costs at December 31

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Others	Total
					($ million)				
2004									
Gross capitalized costs:									
Proved properties	27,540	4,691	43,518	10,450	2,892	10,401		3,834	103,326
Unproved properties	271	154	1,265	411	1,121	476	107	96	3,901
	27,811	4,845	44,783	10,861	4,013	10,877	107	3,930	107,227
Accumulated depreciation	17,637	2,787	19,783	5,532	1,347	5,559		1,011	53,656
Net capitalized costs	10,174	2,058	25,000	5,329	2,666	5,318	107	2,919	53,571
2003									
Gross capitalized costs:									
Proved properties	25,212	4,506	43,480	10,404	3,905	9,751	1	3,260	100,519
Unproved properties	266	211	1,127	661	1,642	506	37	54	4,504
	25,478	4,717	44,607	11,065	5,547	10,257	38	3,314	105,023
Accumulated depreciation	15,346	2,912	19,807	5,067	1,890	5,516	32	1,218	51,788
Net capitalized costs	10,132	1,805	24,800	5,998	3,657	4,741	6	2,096	53,235
2002									
Gross capitalized costs:									
Proved properties	26,804	4,029	46,555	9,406	5,275	7,803		2,120	101,992
Unproved properties	294	179	1,045	806	2,148	479		236	5,187
	27,098	4,208	47,600	10,212	7,423	8,282		2,356	107,179
Accumulated depreciation	16,394	2,591	22,416	4,729	2,360	4,489		1,075	54,054
Net capitalized costs	10,704	1,617	25,184	5,483	5,063	3,793		1,281	53,125

Costs incurred for the year ended December 31

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Others	Total
					($ million)				
2004									
Acquisition of properties:									
Proved									
Unproved	2		58	5		13			78
	2		58	5		13			78
Exploration and appraisal costs (b)	51	17	422	199	85	142	113	9	1,038
Development costs	679	262	3,248	527	88	1,460		1,007	7,271
Total costs	732	279	3,728	731	173	1,615	113	1,016	8,387
2003									
Acquisition of properties:									
Proved									
Unproved									
Exploration and appraisal costs (b)	20	69	290	119	57	205	26	40	826
Development costs	740	236	3,474	512	42	1,614		917	7,535
Total costs	760	305	3,764	631	99	1,819	26	957	8,361
2002									
Acquisition of properties:									
Proved		4						59	63
Unproved			29	7		1			37
		4	29	7		1		59	100
Exploration and appraisal costs (b)	28	68	441	179	161	160	17	54	1,108
Development costs	895	219	3,607	684	129	1,164		526	7,224
Total costs	923	291	4,077	870	290	1,325	17	639	8,432

Results of operations for the year ended December 31

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Others	Total
					($ million)				
2004									
Turnover (c):									
Third parties	3,458	626	1,735	1,785	989	524	5	467	9,589
Sales between businesses	2,423	609	11,603	2,547	519	1,407		2,847	21,955
	5,881	1,235	13,338	4,332	1,508	1,931	5	3,314	31,544
Exploration expense	26	25	361	141	14	45	17	8	637
Production costs	873	117	1,428	535	142	323		131	3,549
Production taxes	273	30	477	239	45			1,023	2,087
Other costs (income) (d)	(211)	38	1,884	458	96	122	(3)	1,380	3,764
Depreciation	1,524	172	2,673	797	174	347		121	5,808
	2,485	382	6,823	2,170	471	837	14	2,663	15,845
Profit before taxation (e)	3,396	853	6,515	2,162	1,037	1,094	(9)	651	15,699
Allocable taxes	1,288	534	2,290	870	104	441	2	151	5,680
Results of operations	2,108	319	4,225	1,292	933	653	(11)	500	10,019
2003									
Turnover (c):									
Third parties	2,257	441	1,491	1,222	421	444		777	7,053
Sales between businesses	2,901	568	10,930	2,684	925	974		1,707	20,689
	5,158	1,009	12,421	3,906	1,346	1,418		2,484	27,742
Exploration expense	17	37	204	164	15	32	21	52	542
Production costs	800	113	1,262	463	166	241		135	3,180
Production taxes	233	14	439	189	40			742	1,657
Other costs (income) (d)	(151)	57	2,019	447	160	38	30	946	3,546
Depreciation	1,830	169	3,384	560	445	222		136	6,746
	2,729	390	7,308	1,823	826	533	51	2,011	15,671
Profit before taxation (e)	2,429	619	5,113	2,083	520	885	(51)	473	12,071
Allocable taxes	1,060	360	2,130	881	97	342	(12)	158	5,016
Results of operations	1,369	259	2,983	1,202	423	543	(39)	315	7,055

2002									
Turnover (c):									
Third parties	2,249	465	1,290	884	457	512		644	6,501
Sales between businesses	3,169	594	7,776	1,754	905	1,015		1,278	16,491
	5,418	1,059	9,066	2,638	1,362	1,527		1,922	22,992
Exploration expense	27	47	258	167	67	50	17	11	644
Production costs	820	104	1,318	403	190	237		122	3,194
Production taxes	279	7	288	115	36			519	1,244
Other costs (income) (d)	315	36	1,556	341	110	331	42	670	3,401
Depreciation	1,875	154	3,118	633	407	364		140	6,691
	3,316	348	6,538	1,659	810	982	59	1,462	15,174
Profit before taxation (e)	2,102	711	2,528	979	552	545	(59)	460	7,818
Allocable taxes	1,327	412	889	480	291	(86)	(18)	220	3,515
Results of operations	775	299	1,639	499	261	631	(41)	240	4,303

The Group's share of joint ventures' and associated undertakings' results of operations in 2004 was a profit of $1,908 million (2003 $851 million profit and 2002 $372 million profit) after deducting a tax charge of $1,078 million (2003 $171 million tax charge and 2002 $110 million tax charge).

The Group's share of joint ventures' and associated undertakings' net capitalized costs at December 31, 2004 was $12,077 million (December 31, 2003 $10,232 million and December 31, 2002 $4,350 million).

The Group's share of joint ventures' and associated undertakings' costs incurred in 2004 was $1,435 million (2003 $6,282 million and 2002 $850 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 fixed assets and businesses or termination of operations relating to the oil and natural gas exploration and production activities, which have been accounted as exceptional items, are also excluded.

(b) Includes exploration and appraisal drilling expenditure and licence acquisition costs which are capitalized within intangible fixed assets and geological and geophysical exploration costs which are charged to income as incurred.

(c)

Turnover represents proceeds from the sale of production and other crude oil and gas including royalty oil sold on behalf of others where royalty is payable in cash.

(d)

Includes the value of royalty oil sold on behalf of others where royalty is payable in cash, property taxes and other government take.

(e)

The exploration and production total operating profit comprises:

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Others	Total
				($ million)					
Year ended December 31, 2004									
Exploration and production activities									
Group (as above)	3,396	853	6,515	2,162	1,037	1,094	(9)	651	15,699
Equity-accounted entities				401	75		2,510		2,986
Midstream activities	9	(15)	(442)	164	(82)	(19)		78	(307)
Total operating profit	3,405	838	6,073	2,727	1,030	1,075	2,501	729	18,378
Year ended December 31, 2003									
Exploration and production activities									
Group (as above)	2,429	619	5,113	2,083	520	885	(51)	473	12,071
Equity-accounted entities			1	199	64		610	148	1,022
Midstream activities	233	(2)	219	211	1	1			663
Total operating profit	2,662	617	5,333	2,493	585	886	559	621	13,756
Year ended December 31, 2002									
Exploration and production activities									
Group (as above)	2,102	711	2,528	979	552	545	(59)	460	7,818
Equity-accounted entities			16	163	70	1	115	117	482
Midstream activities	224		296	138	56	(8)			706
Total operating profit	2,326	711	2,840	1,280	678	538	56	577	9,006

Suspended exploration well costs

Included within the total exploration expenditure of $3,761 million (2003 $4,236 million) shown as part of intangible assets (see Note 21 Intangible assets) is an amount of $1,680 million (2003 $1,698 million) representing costs directly associated with exploration wells.

The carried costs of exploration wells are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. In evaluating whether costs incurred meet the criteria for initial and continued capitalization management uses two main criteria: a) that exploration drilling is still under way or firmly planned, or

b) that it either has been determined, or work is underway to determine, that the discovery is economically viable, based on a range of technical and commercial considerations, and sufficient progress is being made on establishing development plans and timing.

The following table provides an analysis of the amount of costs directly associated with exploration wells:

	At December 31,			
	2004		2003	
	($ million)	Number of wells	($ million)	Number of wells
Exploration well-drilling costs				
Projects with recent or planned drilling activity	690	51	418	48
Projects with completed exploration activity	990	103	1,280	148
At December 31,	1,680	154	1,698	196

The following table provides the year-end balances and movements for suspended exploration well costs:

	Years ended December 31,		
	2004	2003	2002
	($ million)		
Capitalized exploration well costs			
At January 1,	1,698	1,846	1,941
Additions pending determination of proved reserves	391	295	341
Exploration well costs written off in the period	(84)	(90)	(143)
Costs of exploration wells divested in the period	(34)	(76)	(35)
Reclassified to tangible assets following determination of proved reserves	(291)	(277)	(258)
At December 31,	1,680	1,698	1,846

The following table provides an ageing profile of suspended exploration wells:

	At December 31,					
	2004		2003		2002	
	Cost	Wells	Cost	Wells	Cost	Wells
	($ million)		($ million)		($ million)	
Age						
Less than 1 year	411	26	266	34	273	32
1 to 5 years	787	81	752	81	1,038	110
6 to 10	292	29	522	62	363	45
More than 10 years	190	18	158	19	172	20
Total	1,680	154	1,698	196	1,846	207

Note 49 Business and geographical analysis

BP has four reportable operating segments Exploration and Production; Refining and Marketing; Petrochemicals and Gas, Power and Renewables. 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). The activities of Refining and Marketing include oil supply and trading as well as refining and marketing (downstream activities). Petrochemicals activities include petrochemicals manufacturing and marketing. Gas, Power and Renewables activities include marketing and trading of natural gas, natural gas liquids, new market development, LNG and solar and renewables.

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.

Sales between segments are made at prices that approximate market prices, taking into account the volumes involved.

By business

	Exploration and Production	Refining and Marketing	Petro-chemicals	Gas, Power and Renewables	Other businesses and corporate (a)	Eliminations	Total
				($ million)			
2004							
Group turnover third parties	10,158	173,048	20,429	80,878	546		285,059
sales between businesses (b)	24,756	6,539	780	2,442		(34,517)	
	34,914	179,587	21,209	83,320	546	(34,517)	285,059
Share of sales by joint ventures	8,734	594	462				9,790
							294,849
Equity-accounted income (c)	3,183	164	215	15			3,577
Total operating profit (loss) (d)	18,378	6,084	12	926	(973)		24,427
Exceptional items (e)	152	(117)	(563)	56	1,287		815
Profit (loss) before interest and tax	18,530	5,967	(551)	982	314		25,242
Total assets (f)	83,048	66,289	18,877	17,069	7,930		193,213
Operating capital employed (g)	68,718	38,577	14,755	4,901	(8,559)		118,392
Goodwill	3,151	4,712	(29)	38			7,872
Depreciation and amounts provided (h)	6,877	3,423	1,951	215	117		12,583
Capital expenditure and acquisitions	11,193	3,014	2,289	538	215		17,249
2003							
Group turnover third parties	7,868	145,029	15,483	63,676	515		232,571
sales between businesses (b)	22,885	4,448	592	1,963		(29,888)	
	30,753	149,477	16,075	65,639	515	(29,888)	232,571
Share of sales by joint ventures	2,587	453	434				3,474
							236,045
Equity-accounted income (c)	1,186	164	73	(3)	18		1,438
Total operating profit (loss) (d)	13,756	2,483	585	582	(283)		17,123
Exceptional items (e)	913	(213)	38	(6)	99		831
Profit (loss) before interest and tax	14,669	2,270	623	576	(184)		17,954
Total assets (f)	77,703	58,602	16,677	10,607	8,753		172,342
Operating capital employed (g)	63,618	35,111	13,484	4,292	(6,392)		110,113
Goodwill	3,761	5,325	35	48			9,169
Depreciation and amounts provided (h)	6,928	2,958	751	163	140		10,940
Capital expenditure and acquisitions	15,370	3,080	775	441	346		20,012
2002							

	Exploration and Production	Refining and Marketing	Petro-chemicals	Gas, Power and Renewables	Other businesses and corporate (a)	Eliminations	Total
Group turnover third parties	6,974	122,470	12,507	36,260	510		178,721
sales between businesses (b)	18,109	3,366	557	1,320		(23,352)	
	25,083	125,836	13,064	37,580	510	(23,352)	178,721
Share of sales by joint ventures	539	415	511				1,465
							180,186
Equity-accounted income (c)	611	204	(10)	107	52		964
Total operating profit (loss) (d)	9,006	1,969	447	469	(730)		11,161
Exceptional items (e)	(726)	613	(256)	1,551	(14)		1,168
Profit (loss) before interest and tax	8,280	2,582	191	2,020	(744)		12,329
Total assets (f)	71,423	54,505	15,783	7,243	6,667		155,621
Operating capital employed (g)	61,460	33,484	12,536	2,979	(9,768)		100,691
Goodwill	4,371	5,969	43	55			10,438
Depreciation and amounts provided (h)	6,786	2,658	749	130	78		10,401
Capital expenditure and acquisitions	9,659	7,753	823	448	410		19,093

By geographical area

	UK (i)	Rest of Europe	USA	Rest of World	Eliminations	Total
			($ million)			
2004						
Group turnover third parties (j)	52,671	47,494	127,049	57,845		285,059
sales between areas	28,484	6,928	3,603	10,207	(49,222)	
	81,155	54,422	130,652	68,052	(49,222)	285,059
Share of sales by joint ventures	155	296	212	9,127		9,790
						294,849
Equity-accounted income (c)	6	27	99	3,445		3,577
Total operating profit (d)	2,408	3,157	9,138	9,724		24,427
Exceptional items (e)	(343)	(87)	(205)	1,450		815
Profit before interest and tax	2,065	3,070	8,933	11,174		25,242
Total assets (f)	38,700	29,229	69,107	56,177		193,213
Operating capital employed (g)	21,342	13,109	43,507	40,434		118,392
Depreciation and amounts provided (h)	3,314	1,653	5,484	2,132		12,583
Capital expenditure and acquisitions	1,832	2,105	6,301	7,011		17,249
2003						
Group turnover third parties (j)	39,696	41,910	106,741	44,224		232,571
sales between areas	15,275	8,672	2,169	8,274	(34,390)	
	54,971	50,582	108,910	52,498	(34,390)	232,571
Share of sales by joint ventures	144	290	177	2,863		3,474
						236,045
Equity-accounted income (c)	(5)	13	105	1,325		1,438
Total operating profit (d)	1,924	2,271	6,672	6,256		17,123
Exceptional items (e)	717	(151)	(347)	612		831
Profit before interest and tax	2,641	2,120	6,325	6,868		17,954
Total assets (f)	34,199	26,842	63,283	48,018		172,342
Operating capital employed (g)	18,788	11,030	44,322	35,973		110,113
Depreciation and amounts provided (h)	2,963	1,028	5,187	1,762		10,940
Capital expenditure and acquisitions	1,556	1,277	6,291	10,888		20,012
2002						
Group turnover third parties (j)	34,075	38,538	78,282	27,826		178,721
sales between areas	14,673	7,980	2,099	6,575	(31,327)	
	48,748	46,518	80,381	34,401	(31,327)	178,721
Share of sales by joint ventures	129	298	236	802		1,465

	UK (i)	Rest of Europe	USA	Rest of World	Eliminations	Total
						180,186
Equity-accounted income (c)	(4)	130	153	685		964
Total operating profit (d)	1,207	2,195	3,646	4,113		11,161
Exceptional items (e)	(88)	1,817	(242)	(319)		1,168
Profit before interest and tax	1,119	4,012	3,404	3,794		12,329
Total assets (f)	30,838	25,024	62,599	37,160		155,621
Operating capital employed (g)	18,305	11,175	42,695	28,516		100,691
Depreciation and amounts provided (h)	2,821	867	4,780	1,933		10,401
Capital expenditure and acquisitions	1,619	6,556	6,095	4,823		19,093

(a) Other businesses and corporate comprises Finance, the Group's coal asset (divested in October 2003) and aluminium asset, its investments in PetroChina and Sinopec (both divested in early 2004), interest income and costs relating to corporate activities worldwide.

Note 49 Business and geographical analysis (concluded)

(b)

Sales and transfers between businesses are made at prices that approximate market prices taking into account the volumes involved.

(c)

Equity-accounted income (loss) represents the Group's share of income (loss) before exceptional items, interest expense and taxes of joint ventures and associated undertakings.

(d)

Total operating profit is before interest expense and other finance expense, which is attributable to the corporate function. Transfers between Group companies are made at prices that approximate market prices taking into account the volumes involved.

(e)

Exceptional items comprise profit on the sale of fixed assets and sale of businesses or termination of operations of $815 million in 2004 (2003 $831 million profit and 2002 $1,168 million profit).

(f)

Total assets comprise fixed and current assets and pension surpluses and include investments in joint ventures and associated undertakings analyzed between activities as follows:

	Exploration and Production	Refining and Marketing	Petro-chemicals	Gas, Power and Renewables	Other businesses and corporate (a)	Total
			($ million)			
2004	14,336	1,522	1,493	573	15	17,939
2003	12,418	1,381	1,691	362	27	15,879
2002	5,687	1,452	1,252	210	56	8,657

(g)

Operating capital employed comprises net assets before deducting finance debt and liabilities for current and deferred taxation.

	At December 31,		
	2004	2003	2002
		($ million)	
Operating capital employed	118,392	110,113	100,691
Liabilities for current and deferred taxation	(17,302)	(16,068)	(14,211)
Capital employed	101,090	94,045	86,480

(h)

Depreciation consists of charges for depreciation, depletion and amortization of property, plant and equipment, amortization of goodwill and other intangibles and amounts provided against fixed asset investments.

(i) United Kingdom area includes the UK-based international activities of Refining and Marketing.

(j) Turnover to third parties is stated by origin which is not materially different from turnover by destination.

Note 50 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 undivided interests in pipelines from production facilities to terminals for shipping or onward transmission (such as the Trans Alaska Pipeline System and UK Central Area Transmission System) and oil and natural gas exploration and production activities where the Group has a direct interest in the field or a contractual right to a share of production. The operations of the pipeline or field may be undertaken by one participant on behalf of all other participants or by a company specifically created for this purpose. In either case contractual arrangements specify the allocation of costs between participants. US GAAP permits such arrangements 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, 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 (i.e. operating results after exceptional items, 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.

The following summarizes the reclassifications for joint ventures and associated undertakings necessary to accord with US GAAP.

	Year ended December 31, 2004		
Increase (decrease) in caption heading	**As reported**	**Reclassification**	**US GAAP presentation**
		($million)	
Consolidated statement of income			
Other income	675	2,198	2,873
Share of profits of JVs and associated undertakings	3,577	(3,577)	
Exceptional items before taxation	815		815
Interest expense	642	(206)	436
Taxation	8,282	(1,173)	7,109
Profit for the year	15,731		15,731

Increase (decrease) in caption heading	Year ended December 31, 2003 As reported	Reclassification	US GAAP presentation
		($million)	
Consolidated statement of income			
Other income	786	1,080	1,866
Share of profits of JVs and associated undertakings	1,438	(1,438)	
Exceptional items before taxation	831		831
Interest expense	644	(134)	510
Taxation	6,111	(224)	5,887
Profit for the year	10,482		10,482

Increase (decrease) in caption heading	Year ended December 31, 2002 As reported	Reclassification	US GAAP presentation
		($million)	
Consolidated statement of income			
Other income	641	563	1,204
Share of profits of JVs and associated undertakings	964	(964)	
Exceptional items before taxation	1,168	(2)	1,166
Interest expense	1,067	(141)	926
Taxation	4,317	(262)	4,055
Profit for the year	6,795		6,795

(b) 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.

(c) Deferred taxation/Business combinations

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.

Certain subsidiaries, principally in the US, have inventories valued on the last-in, first-out (LIFO) basis for tax purposes. The difference between the book and tax valuation is not a timing difference for UK GAAP but is a temporary difference for US GAAP.

The adjustments to profit for the year and to BP shareholders' interest to accord with US GAAP are summarized below.

	Years ended December 31,		
Increase (decrease) in caption heading	**2004**	**2003**	**2002**
	($million)		
Cost of sales	2,048	1,550	852
Taxation	(1,457)	(1,381)	(249)
Profit for the year	(591)	(169)	(603)

	At December 31,	
	2004	**2003**
	($ million)	
Tangible assets	4,052	6,084
Deferred taxation	5,585	7,022
BP shareholders' interest	(1,533)	(938)

The major components of deferred tax liabilities and assets on a US GAAP basis were as follows:

	December 31,	
	2004	**2003**
	($million)	
Depreciation	(20,434)	(22,705)
Other taxable temporary differences	(3,711)	(3,715)
Total deferred tax liabilities	(24,145)	(26,420)
Petroleum revenue tax	578	601
Decommissioning and other provisions	1,890	2,743
Tax credit and loss carry forward	668	105
Other deductible temporary differences	356	222
Gross deferred tax assets	3,492	3,671
Valuation allowance	(888)	
Net deferred tax assets	2,604	3,671
Net deferred tax liability*	(21,541)	(22,749)

*

Primarily noncurrent.

(d) 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. The provisions for decommissioning and environmental liabilities are estimated using costs based on current prices and discounted using real discount rates. Unwinding of the discount and the effect of a change in the discount rate is included in other finance 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.

US GAAP 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. Unwinding of the discount is included in operating profit for the year.

The provisions for decommissioning under SFAS 143 are set up on a similar basis to UK GAAP except that estimated future cash outflows are discounted using a credit-adjusted risk-free rate rather than a real discount rate.

The cumulative effect of adopting SFAS 143 at January 1, 2003 resulted in an after-tax credit to income, as adjusted to accord with US GAAP, of $1,002 million. The effect of adoption also included an increase in total assets, as adjusted to accord with US GAAP, of $687 million and a reduction in total liabilities, as adjusted to accord with US GAAP, of $315 million. The effect of adoption on the year ended December 31, 2003 was to decrease profit for the period by $44 million, before cumulative effect of accounting changes as adjusted to accord with US GAAP.

Under US GAAP environmental liabilities are discounted only where the timing and amounts of payments are fixed and reliably determined.

In addition, use of different oil and natural gas reserve volumes (see (e)) results in different field lives and hence different decommissioning provisions under UK and US GAAP.

The adjustments to profit for the year and to BP shareholders' interest to accord with US GAAP are summarized below.

	Years ended December 31,		
Increase (decrease) in caption heading	**2004**	**2003**	**2002**
		($million)	
Cost of sales	382	188	334
Other finance expense	(237)	(173)	(212)
Taxation	(5)	(64)	(130)
Profit for the year before cumulative effect of accounting changes	(140)	49	8
Cumulative effect of accounting changes		1,002	
Profit for the year	(140)	1,051	8

	At December 31,	
	2004	2003
	($million)	
Tangible assets	(1,667)	(835)
Provisions	(1,454)	(636)
Deferred taxation	(76)	(71)
BP shareholders' interest	(137)	(128)

The following data summarizes the movements in the asset retirement obligation, as adjusted to accord with US GAAP, for the years ended December 31, 2004 and 2003.

	Years ended December 31,	
	2004	2003
	($million)	
At January 1, 2004	3,872	3,474
Exchange adjustments	175	219
New provisions/adjustment to provisions	(174)	855
Unwinding of discount	208	187
Utilized/deleted	(183)	(863)
	3,898	3,872

The following pro forma data summarize the results of operations for the years ended December 31, 2003 and 2002 assuming SFAS 143 was applied retroactively.

	Years ended December 31,	
	2003 (a)	2002
	($ million)	
Profit for the year applicable to ordinary shares as adjusted to accord with US GAAP		
As reported	12,939	8,107
Pro forma	11,937	8,117
Per ordinary share cents		
Basic as reported	58.36	36.20
Basic pro forma	53.84	36.24
Diluted as reported	57.79	36.02
Diluted pro forma	53.33	36.07
Per American Depositary Share cents		
Basic as reported	350.16	217.20
Basic pro forma	323.04	217.44
Diluted as reported	346.74	216.12
Diluted pro forma	319.98	216.42

(a) Pro forma data for the year ended December 31, 2003 excludes the cumulative effect of adoption.

(e) Oil and natural gas reserve differences

The US Securities and Exchange Commission (SEC) rules for estimating reserves are different in certain respects from the UK Statement of Recommended Practice 'Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities' (SORP); in particular, the SEC requires the use of year-end prices, whereas under the SORP the Group uses long-term planning prices. Any consequent difference in reserve volumes results in different charges for depreciation, depletion and amortization between UK and US GAAP.

Applying higher year-end prices to reserve estimates and assuming they apply to the end-of-field life has the effect of increasing proved reserves associated with concessions (tax and royalty arrangements) for which additional development opportunities become economically viable at higher prices or where higher prices make it more economic to extend the life of the field. Conversely, applying higher year-end prices to reserves in fields subject to PSAs has the effect of decreasing proved reserves from those fields because higher prices result in lower volume entitlements. The impact of these changes on reserves results in a higher net depreciation charge in the year.

Included in the SFAS 143 adjustment is the impact of the use of the year-end price in estimating proved reserves. This results in a lower provision being required on the balance sheet for tax and royalty arrangements and a higher provision for those PSAs where there is a decommissioning obligation.

The adjustments to profit for the year and to BP shareholders' interest to accord with US GAAP are summarized below.

	Years ended December 31,		
Increase (decrease) in caption heading	**2004**	**2003**	**2002**
		($million)	
Cost of sales	(48)		
Taxation	18		
Profit for the year	30		

	At December 31,	
	2004	**2003**
	($million)	
Tangible assets	48	
Deferred taxation	18	
BP shareholders' interest	30	

(f) Revisions to fair market values

UK GAAP permits assets and liabilities acquired in a business combination to be revised during the year following that in which the acquisition was made. Under US GAAP, subsequent to determining acquisition date fair values, such adjustments are not permitted.

In 2003, revisions were made to the previously reported fair values for tangible fixed assets (decrease of $76 million) and other provisions (decrease of $365 million) relating to the 2002 acquisition of Veba. Under US GAAP, the revisions were included in cost of sales.

The adjustments to profit for the year to accord with US GAAP are summarized below. The consequential Balance Sheet adjustments are reflected in (c) Deferred taxation/Business combinations and (h) Goodwill and intangible assets.

	Years ended December 31,		
Increase (decrease) in caption heading	**2004**	**2003**	**2002**
		($ million)	
Cost of sales		(330)	
Taxation		41	
Profit for the year		289	

(g) Sale and leaseback

The sale and leaseback of an office building in Chicago, Illinois in 1998 was treated as a sale for UK GAAP whereas for US GAAP it was treated as a financing transaction. The remaining interest in this building was sold in January 2003.

Provisions were recognized under UK GAAP in 1999 and 2002 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 was reversed for US GAAP. Following the disposal of the building a provision has now been recognized for US GAAP.

Under UK GAAP the profit arising on the sale and operating leaseback of certain railcars in 1999 was taken to income in the period in which the transaction occurred. Under US GAAP this profit is being 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,		
	2004	2003	2002
	($million)		
Cost of sales	10	(106)	(40)
Taxation	(4)	37	16
Profit for the year	(6)	69	24

	At December 31,	
	2004	2003
	($million)	
Other accounts payable and accrued liabilities	21	24
Provisions	45	32
Deferred taxation	(23)	(19)
BP shareholders' interest	(43)	(37)

(h) Goodwill and intangible assets

There are two main differences in the basis for determining goodwill between UK and US GAAP which result in the amount of goodwill for US GAAP reporting differing from the amount recognized under UK GAAP.

Goodwill represents the difference between the consideration paid in an acquisition and the fair value of the assets and liabilities acquired. Where shares are issued in connection with an acquisition, UK GAAP requires that the shares issued be valued at the time the public offer becomes unconditional. For US GAAP the consideration is determined at the date the offer is made.

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 the assets acquired and liabilities assumed in an acquisition, whereas under UK GAAP no such deferred tax liability or 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.

Under UK GAAP, goodwill is amortized and a review for impairment is carried out if events or changes in circumstances indicate that the carrying amount of the goodwill may not be recoverable. For US GAAP goodwill and indefinite lived intangible assets are not amortized, but are subject to an annual impairment test. Amortization of goodwill charged to income under UK GAAP is reversed for US GAAP. The Group does not have any other intangible assets with indefinite lives.

During the fourth quarter of 2004 the Group completed a goodwill impairment review using the two-step process prescribed in SFAS 142. The first step includes a comparison of the fair value of a reporting unit to its carrying value, including goodwill. Where the carrying value exceeds the fair value, the goodwill of the reporting unit is potentially impaired and the second step is then completed in order to measure the impairment loss, if any. No impairment charge resulted from this review. For the purposes of this impairment review the reporting unit is one level below an operating segment.

The adjustments to profit for the year and to BP shareholders' interest to accord with US GAAP are summarized below.

	Years ended December 31,		
Increase (decrease) in caption heading	**2004**	**2003**	**2002**
		($million)	
Cost of sales	(1,436)	(1,376)	(1,302)
Profit for the year	1,436	1,376	1,302

	At December 31,	
	2004	**2003**
	($ million)	
Intangible assets	3,207	1,669
BP shareholders' interest	3,207	1,669

In accordance with Group accounting practice, exploration licence acquisition costs are capitalized initially as an intangible fixed asset and are amortized over the estimated period of exploration. Where proved reserves of oil or natural gas are determined and development is sanctioned, the unamortized cost is transferred to tangible production assets. Where exploration is unsuccessful, the unamortized cost is charged against income. At December 31, 2004 and December 31, 2003, exploration licence acquisition costs included in the Group's tangible fixed assets and intangible fixed assets, net of accumulated amortization, were as follows.

	At December 31,	
	2004	**2003**
	($ million)	
Exploration licence acquisition cost included in fixed assets (net of accumulated amortization)		
Tangible fixed assets	1,100	1,300
Intangible fixed assets	595	600

Changes to exploration expenditure, goodwill and other intangible assets, as adjusted to accord with US GAAP, during the years ended December 31, 2004 and 2003 are shown below.

	Exploration expenditure	Goodwill	Gain on asset exchange (see (j))	Additional minimum pension liability (see (k))	Other intangibles	Total
			($ million)			
Net book amount						
At January 1, 2003	4,944	10,354	167	150	184	15,799
Amortization expense	(297)		(19)		(51)	(367)
Other movements	(411)	484		(107)	104	70
At January 1, 2004	4,236	10,838	148	43	237	15,502
Amortization expense	(274)		(19)		(72)	(365)
Other movements	(201)	566	(83)	(4)	278	556
At December 31, 2004	3,761	11,404	46	39	443	15,693

Amortization expense relating to other intangibles is expected to be in the range $60-$80 million in each of the succeeding five years.

(i) Derivative financial instruments and hedging activities

US GAAP 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 that certain criteria are met, hedge accounting is permitted but not required.

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 both UK and 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 US GAAP. 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 certain of these 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. Under SFAS 133, these contracts are marked-to-market.

In October 2002, the FASB Emerging Issues Task Force (EITF) reached a consensus with regards to EITF Issue No. 02-3, 'Issues Involved in Accounting for Contracts Under EITF Issue No. 98-10 'Accounting for Contracts Involved in Energy Trading and Risk Management Activities' (EITF 02-3). This consensus, which rescinded EITF Issue No. 98-10 'Accounting for Contracts Involved in Energy Trading and Risk Management Activities' (EITF 98-10), requires all energy-related, non-derivative contracts (such as transportation, storage, tolling, and requirements contracts that do not meet the definition of a derivative) to be accounted for as executory contracts on an accrual basis. Under EITF 98-10, such contracts were accounted for at fair value.

The consensus is applicable for all contracts executed after October 25, 2002. Application of the consensus to contracts existing prior to October 26, 2002 is required to be accounted for as a cumulative effect of a change in accounting principle effective for periods beginning after December 15, 2002.

For BP's reporting under UK GAAP, energy-related non-derivative contracts associated with trading activities are marked to market with gains and losses recognized in the income statement.

The cumulative effect of adopting the consensus at January 1, 2003 resulted in an after tax credit to income, as adjusted to accord with US GAAP, of $50 million.

EITF 02-3 also requires trading inventories to be accounted for at historical cost. The Group marks trading inventories to market at the balance sheet date. As such, a UK/US GAAP difference arises which impacts both profit for the year and BP shareholders' interest due to the difference in inventory valuations.

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,**		
	2004	**2003**	**2002**
		($ million)	
Cost of sales	231	(27)	(842)
Taxation	(56)	15	302
Profit for the year before cumulative effect of accounting change	(175)	12	540
Cumulative effect of accounting change, net of taxation		50	
Profit for the year	(175)	62	540

	At December 31,	
	2004	2003
	($ million)	
Inventories	100	(150)
Accounts payable and accrued liabilities	423	(58)
Deferred taxation	(73)	(20)
BP shareholders' interest	(250)	(72)

(j) Gain arising on asset exchange

For UK GAAP the transaction with Solvay in 2001, 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 gave rise to a gain on disposal of $242 million ($157 million after tax). For US GAAP reporting, the gain is being recognized over 10 years.

In November 2004, the Group acquired Solvay's interests in BP Polyethylene Europe and BP Solvay Polyethylene North America. As a result, part of the gain has been recognized in 2004.

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,		
	2004	2003	2002
	($ million)		
Cost of sales	105	25	27
Taxation	(37)	(8)	(9)
Profit for the year	(68)	(17)	(18)

	At December 31,	
	2004	2003
	($ million)	
Intangible assets	46	148
Accounts payable and accrued liabilities	(48)	(51)
Deferred taxation	33	70
BP shareholders' interest	61	129

(k) Pensions and other postretirement benefits

With effect from January 1, 2004 BP adopted Financial Reporting Standard No. 17 'Retirement Benefits' (FRS 17). Under FRS 17, net surpluses and deficits of funded schemes for pensions and other postretirement benefits are included in the Group balance sheet at their fair values and all movements are reflected in the income statement, except for actuarial gains and losses which are reflected in the Statement of Total Recognized Gains and Losses. This contrasts with Statement of Financial Accounting Standards No. 87 'Employers' Accounting for Pensions' (SFAS 87) under which actuarial gains and losses are not recognized as they occur but are recognized systematically and gradually over subsequent periods. 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 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,**		
	2004	**2003**	**2002**
	($ million)		
Cost of sales	330	694	(214)
Other finance expense	(29)	(340)	139
Taxation	(254)	(139)	25
Profit for the year	(47)	(215)	50

	At December 31,	
	2004	**2003**
	($ million)	
Intangible assets	39	43
Other receivables falling due after more than one year	7,104	6,814
Provisions for liabilities and charges other	8,973	7,356
Defined benefit pension plan surpluses	(1,475)	(1,146)
Defined benefit pension plan deficits	5,863	5,005
Other postretirement benefit plan deficit	2,126	2,630
Deferred taxation	595	744
BP shareholders' interest	4,089	5,246

(l) Impairments

Under UK GAAP, in determining the amount of any impairment loss, the carrying value of fixed assets and goodwill is compared with the discounted value of the future cash flows. Under US GAAP an initial step is required whereby the carrying value is compared with the undiscounted future cash flows, and only if the carrying value is less than the undiscounted cash flows is an impairment loss recognized.

Certain of the UK GAAP impairment charges recognized by Exploration and Production and Petrochemicals have been reversed for US GAAP.

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,		
	2004	2003	2002
	($ million)		
Cost of sales	(986)		
Taxation	309		
Profit for the year	677		

	At December 31,	
	2004	2003
	($ million)	
Intangible assets	325	
Tangible assets	661	
Deferred taxation	309	
BP shareholders' interest	677	

(m) Provisions for severance and operating costs

The recognition criteria for costs associated with severance and restructuring provisions are similar under UK and US GAAP. However, in the following situations a provision under UK GAAP does not qualify as a provision under US GAAP: (i) future operating losses are recognized when they occur; and (ii) where employees are required to render service beyond a minimum retention period, the termination benefit associated with those employees is recognized over the future period.

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,**		
	2004	**2003**	**2002**
	($ million)		
Cost of sales	(87)		
Taxation	27		
Profit for the year	60		

	At December 31,	
	2004	**2003**
	($ million)	
Provisions	(87)	
Deferred taxation	27	
BP shareholders' interest	60	

(n) Equity-accounted investments

Under UK GAAP the Group's accounting policies are applied in arriving at the amounts to be included in the financial statements in relation to equity-accounted investments. The major difference between UK and US GAAP in this respect relates to deferred tax which is provided on the basis of timing differences under UK GAAP. US GAAP requires provision for deferred tax to be made for temporary differences between carrying values and the related tax base.

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,**		
	2004	**2003**	**2002**
	($ million)		
Taxation	(226)		
Profit for the year	226		

	At December 31,	
	2004	**2003**
	($ million)	
Fixed assets Investments	(226)	
BP shareholders' interest	226	

(o) 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.

	At December 31,	
Increase (decrease) in caption heading	**2004**	**2003**
	($ million)	
Other accounts payable and accrued liabilities	(1,822)	(1,495)
BP shareholders' interest	1,822	1,495

(p) Investments

Under UK GAAP certain of the Group's equity investments are reported as either fixed asset or current 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.

In February 2003, BP called its $420 million Exchangeable Bonds which were exchangeable for Lukoil American Depositary Shares (ADSs). Bondholders converted to ADSs before the redemption date. For the year ended December 31, 2003, gains of $99 million were reclassified from comprehensive income to net income.

The Group sold its investments in PetroChina and Sinopec in January and February 2004, respectively, resulting in a gain on disposal of $1,314 million. For the year ended December 31, 2004 gains of $1,165 million were reclassified from comprehensive income to net income.

The adjustment to BP shareholders' interest to accord with US GAAP is shown below.

	At December 31,	
Increase (decrease) in caption heading	**2004**	**2003**
	($ million)	
Fixed assets Investments	344	1,924
Deferred taxation	117	673
BP shareholders' interest	227	1,251

(q) Consolidation of variable interest entities

In January 2003, the FASB issued FASB Interpretation No. 46 'Consolidation of Variable Interest Entities' (Interpretation 46). Interpretation 46 clarifies the application of existing consolidation requirements to entities where a controlling financial interest is achieved through arrangements that do not involve voting interests. Under Interpretation 46, a variable interest entity is consolidated if a company is subject to a majority of the risk of loss from the variable interest entity's activities or entitled to receive a majority of the entity's residual returns.

The Group currently has several ships under construction which are accounted for under UK GAAP as operating leases. Under Interpretation 46 certain of the arrangements represent variable interest entities that would be consolidated by the Group. The maximum exposure to loss as a result of the Group's involvement with these entities is limited to the debt of the entity, less the fair value of the ships at the end of the lease term.

The adoption of Interpretation 46 did not have a significant effect on profit, as adjusted to accord with US GAAP. The adjustment to BP shareholders' interest to accord with US GAAP are summarized below.

	At December 31,	
Increase (decrease) in caption heading	**2004**	**2003**
	($ million)	
Tangible assets	507	217
Accounts payable and accrued liabilities	(507)	(217)
BP shareholders' interest		

(r) Balance sheet

Under US GAAP Other receivables due after one year of $2,301 million at December 31, 2004 ($2,518 million at December 31, 2003), included within current assets, would have been classified as noncurrent assets. Borrowing under US Industrial Revenue/Municipal Bonds of $2,487 million ($2,503 million at December 31, 2003) 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.

(s) Statement of income

The Group's accounting policy under UK GAAP is to present oil, natural gas, NGL and power forward sales and purchases on a gross basis in the income statement. Previously, for US GAAP, revenues associated with the forward contracts in oil, gas, NGLs and power were also presented on a gross basis. This conclusion was based on the guidance in Financial Accounting Standards Board (FASB) Emerging Issues Task Force (EITF) Issue No. 03-11 "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" As Defined in EITF Issue No. 02-03" (EITF 03-11), and EITF Issue No. 99-19 "Reporting Revenue Gross as a Principal versus Net as an Agent" (EITF 99-19). Under the provisions of EITF 99-19, whether revenues are recognized gross or net is a matter of judgment that depends upon the relevant facts and circumstances and an evaluation of the factors and indicators set forth in EITF 99-19.

In accordance with EITF 99-19, the Group concluded that revenues associated with these activities should be presented gross, based on principal versus agent analysis. This decision was based primarily on the following factors: (i) the Group was the primary obligator in the arrangement; (ii) the Group had discretion to set the selling price with the customer; (iii) the Group had discretion to select the supplier; (iv) the Group took title to the commodity, albeit often for a short period of time; and (v) the Group was invoiced for the full amount of the transaction and had this liability to a third party, although master netting agreements mitigated the credit risk.

During 2005, a review was undertaken into forward contracts in oil, gas, NGLs and power and related activity under US GAAP in the context of the review undertaken for the final transition to IFRS for the Group's 2005 year end financial reporting. The review, for IFRS purposes, concluded that revenues associated with OTC forward contracts, where market mechanisms, similar to exchange traded instruments, have developed for financial net settlement and where frequent buying and selling patterns are present which are not part of optimizing Group assets, but which are indicative of the intent to generate profits from short term differences in prices, should be presented net. As a result of this review, the Group reassessed its recognition of revenues associated with these contracts under US GAAP and determined that the provisions of EITF Issue No. 02-03 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-03), should have been applied rather than the provisions of EITF 03-11 (and therefore EITF 99-19) since this element of the Group's activity should have been considered as "trading' as defined under US GAAP for all periods presented. As such, these transactions should be reflected net for purposes of US GAAP for all periods presented. In addition, in connection with the preparation of this Form 20-F/A we identified additional transactions which should also have been presented net under US GAAP. Therefore, revenues and cost of sales for the years ended December 31, 2004, 2003 and 2002 would have been different under US GAAP, than those amounts reported under UK GAAP. While reducing the reported amount of revenues and cost of sales by $81,756 million, $58,956 million and $32,730 million respectively, the reporting of these transactions on a net basis did not impact the Group's profit for the year as adjusted to accord with US GAAP, profit per ordinary share, cash flows or financial position.

Under APB 20 paragraph 13, the fact that the transactions were not viewed as "trading' in nature represented an "oversight or misuse of facts that existed at the time the financial statements were prepared" and, therefore, was an error.

Under US GAAP the Group's accounting policy is that gains and losses on derivative contracts and the revenues and costs associated with other contracts which are classified as held for trading purposes are reported on a net basis in the Consolidated Statement of Income.

Under both UK and US GAAP, changes in the fair value of exchange traded and OTC derivative financial instruments held for the purposes of both risk management and trading giving rise to gains and losses, both realized and unrealized, are shown net when recognized in the income statement.

The disclosure requirements of EITF 02-03 are set out below. For the Group, energy trading contracts in oil, natural gas, NGLs and power comprise exchange-traded derivative instruments such as future and options and non-exchange-traded instruments such as swaps, "over-the-counter' options and forward contracts.

The following tables show the net fair value of contracts held for trading purposes at December 31, 2004 and 2003 analyzed by maturity period and by methodology of fair value estimation.

	Fair value of contracts at December 31, 2004				
	Maturity less than 1 year	Maturity 1 3 years	Maturity 4 5 years	Maturity over 5 years	Total fair value
	($ million)				
Prices actively quoted	111	(89)			22
Prices provided by other external sources	128	169	62		359
Prices based on models and other valuation methods	4	3	1	62	70
	243	83	63	62	451

	Fair value of contracts at December 31, 2003				
	Maturity less than 1 year	Maturity 1 3 years	Maturity 4 5 years	Maturity over 5 years	Total fair value
	($ million)				
Prices actively quoted	(37)				(37)
Prices provided by other external sources	(14)	123	32		141
Prices based on models and other valuation methods	30			37	67
	(21)	123	32	37	171

The following tables show the changes during the year in the net fair value of instruments held for trading purposes for the years 2004, 2003 and 2002:

	Fair value oil price contracts	Fair value natural gas and NGL price contracts	Fair value power price contracts
		($ million)	
Fair value of contracts at January 1, 2004	(154)	191	134
Contracts realized or settled in the year	154	259	54
Unrealized gains (losses) recognized at inception of contract	(33)	73	(3)
Unrealized gains (losses) recognized as a result of changes in valuation techniques and assumptions			
Other unrealized gains (losses) recognized during the year	(107)	(109)	(8)
Fair value of contracts at December 31, 2004	(140)	414	177
Fair value of contracts at January 1, 2003	(66)	124	79
Contracts realized or settled in the year	66	61	49
Unrealized gains (losses) recognized at inception of contract	(20)	(64)	
Unrealized gains (losses) recognized as a result of changes in valuation techniques and assumptions			
Other unrealized gains (losses) recognized during the year	(134)	70	6
Fair value of contracts at December 31, 2003	(154)	191	134
Fair value of contracts at January 1, 2002	6	208	50
Contracts realized or settled in the year	(6)	(194)	(4)
Unrealized gains (losses) recognized at inception of contract	1	(162)	(45)
Unrealized gains (losses) recognized as a result of changes in valuation techniques and assumptions			
Other unrealized gains (losses) recognized during the year	(67)	272	78
Fair value of contracts at December 31, 2002	(66)	124	79

In addition to the risk management activities related to equity crude disposal, refinery supply and marketing, BP's supply and trading function undertakes trading in the full range of conventional derivative financial and commodity instruments and physical cargoes available in the energy markets. 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.

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, 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 approximately 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 models take account of derivative financial instruments such as oil, natural gas and power price futures and swap agreements. Financial assets and liabilities and physical crude oil and refined products that are treated as trading positions are also included in these calculations. For options, a linear approximation is included in the value-at-risk models. The value-at-risk calculation for oil, natural gas, NGLs and power 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 energy trading activities.

	High	Low	Average	December 31
		($ million)		
2004				
Oil price trading	55	18	29	45
Natural gas and NGL price trading	42	11	23	18
Power price trading	18	2	8	7
2003				
Oil price trading	34	17	26	27
Natural gas and NGL price trading	29	4	16	18
Power price trading	13		4	6
2002				
Oil price trading	34	14	23	19
Natural gas and NGL price trading	18	1	6	9
Power price trading	9	1	4	3

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 United States (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 inventory valuation.

Profit for the year

	Years ended December 31,		
	2004	**2003**	**2002**
	($ million except per share amounts)		
Profit as reported in the consolidated statement of income	15,731	10,482	6,795
Deferred taxation/business combinations (c)	(591)	(169)	(603)
Provisions (d)	(140)	49	8
Oil and natural gas reserve differences (e)	30		
Revisions to fair market values (f)		289	
Sale and leaseback (g)	(6)	69	24
Goodwill and intangible assets (h)	1,436	1,376	1,302
Derivative financial instruments (i)	(175)	12	540
Gain arising on asset exchange (j)	(68)	(17)	(18)
Pensions and other postretirement benefits (k)	(47)	(215)	50
Impairments (l)	677		
Provisions for severance and operating costs (m)	60		
Equity-accounted investments (n)	226		
Other	(43)	13	11
Profit for the year before cumulative effect of accounting changes as adjusted to accord with US GAAP	17,090	11,889	8,109
Cumulative effect of accounting changes:			
Provisions (d)		1,002	
Derivative financial instruments (i)		50	
Profit for the year as adjusted to accord with US GAAP	17,090	12,941	8,109
Dividend requirements on preference shares	2	2	2
Profit for the year applicable to ordinary shares as adjusted to accord with US GAAP	17,088	12,939	8,107
Profit for the year as adjusted:			
Per ordinary share cents			
Basic before cumulative effect of accounting changes	78.31	53.62	36.20
Cumulative effect of accounting changes		4.74	
	78.31	58.36	36.20
Diluted before cumulative effect of accounting changes	76.88	53.10	36.02
Cumulative effect of accounting changes		4.69	
	76.88	57.79	36.02
Per American Depositary Share cents (2)			
Basic before cumulative effect of accounting changes	469.86	321.72	217.20
Cumulative effect of accounting changes		28.44	

	Years ended December 31,		
	469.86	350.16	217.20
Diluted before cumulative effect of accounting changes	461.28	318.60	216.12
Cumulative effect of accounting changes		28.14	
	461.28	346.74	216.12

BP shareholders' interest

	December 31, 2004	December 31, 2003
	($ million)	
BP shareholders' interest as reported in the consolidated balance sheet	76,656	70,595
Deferred taxation/business combinations (c)	(1,533)	(938)
Provisions (d)	(137)	(128)
Oil and natural gas reserve differences (e)	30	
Sale and leaseback (g)	(43)	(37)
Goodwill and intangible assets (h)	3,207	1,669
Derivative financial instruments (i)	(250)	(72)
Gain arising on asset exchange (j)	61	129
Pensions and other postretirement benefits (k)	4,089	5,246
Impairments (l)	677	
Provisions for severance and operating costs (m)	60	
Equity-accounted investments (n)	226	
Dividends (o)	1,822	1,495
Investments (p)	227	1,251
Other		(43)
BP shareholders' interest as adjusted to accord with US GAAP	85,092	79,167

(1) The profit as reported under UK GAAP for the years ended December 31, 2003 and December 31, 2002, and BP shareholders' interest at December 31, 2003, have been restated to reflect the adoption of FRS 17 and UITF 38. Consequently certain of the adjustments in the UK/US GAAP reconciliation have also been restated. Profit for the year and BP shareholders' interest, as adjusted to accord with US GAAP, are unaffected by the adoption of FRS 17 and UITF 38.

(2) One American Depositary Share is equivalent to six ordinary shares.

Comprehensive income

The components of comprehensive income, net of related tax are as follows:

	Years ended December 31,		
	2004	2003	2002
	($ million)		
Profit for the period as adjusted to accord with US GAAP	17,090	12,941	8,109
Currency translation differences	2,143	3,644	3,284
Investments			
Unrealized gains	141	1,316	84
Unrealized losses			(48)
Less: reclassification adjustment for gains included in net income	(1,165)	(99)	
Additional minimum pension liability	(838)	1,887	(1,222)
Comprehensive income	17,371	19,689	10,207

Accumulated other comprehensive income at December 31, 2004 comprised currency translation gains of $4,361 million (gains of $2,218 million at December 31, 2003), pension liability adjustments of $1,115 million ($277 million at December 31, 2003) and net unrealized gains on investments of $227 million ($1,251 million gain at December 31, 2003).

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.

The statement of consolidated cash flows presented in accordance with SFAS 95 is as follows:

	Years ended December 31,		
	2004	2003	2002
		($ million)	
Operating activities			
Profit after taxation	15,961	10,652	6,872
Adjustments to reconcile profit after tax to net cash provided by operating activities			
Depreciation and amounts provided	12,583	10,940	10,401
Exploration expenditure written off	274	297	385
Net charge for pensions and other postretirement benefits, less contributions	(39)	(2,573)	(178)
Share of profits of joint ventures and associated undertakings less dividends received	2	(532)	3
(Profit) loss on sale of businesses and fixed assets	(815)	(831)	(1,166)
Working capital movement (a)	(4,073)	(2,270)	(1,060)
Deferred taxation	200	1,192	1,169
Other	181	66	(383)
Net cash provided by operating activities	24,274	16,941	16,043
Investing activities			
Capital expenditures	(13,243)	(12,567)	(12,198)
Acquisitions, net of cash acquired	(1,503)	(211)	(4,324)
Acquisition of investment in TNK-BP joint venture	(1,250)	(2,351)	
Investment in associated undertakings	(942)	(987)	(971)
Net investment in joint ventures	(272)	(178)	(354)
Proceeds from disposal of assets	5,048	6,432	6,782
Net cash used in investing activities	(12,162)	(9,862)	(11,065)
Financing activities			
Proceeds from shares issued (repurchased)	(7,208)	(1,889)	(573)
Proceeds from long-term financing	2,675	4,322	3,707
Repayments of long-term financing	(2,204)	(3,560)	(2,369)
Net (decrease) increase in short-term debt	(40)	(2)	(602)
Dividends paid BP shareholders	(6,041)	(5,654)	(5,264)
Minority shareholders	(33)	(20)	(40)
Net cash used in financing activities	(12,851)	(6,803)	(5,141)
Currency translation differences relating to cash and cash equivalents	91	121	90
Increase (decrease) in cash and cash equivalents	(648)	397	(73)
Cash and cash equivalents at beginning of year	2,132	1,735	1,808
Cash and cash equivalents at end of year	1,484	2,132	1,735

(a) Working capital:			
Inventories (increase) decrease	(3,595)	(841)	(1,521)
Receivables (increase) decrease	(10,770)	(3,025)	(2,445)
Current liabilities excluding finance debt increase (decrease)	10,292	1,596	2,906
	(4,073)	(2,270)	(1,060)

Impact of new US accounting standards

Other postretirement benefits: In May 2004, the FASB issued Staff Position No. 106-2 'Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003' (the Medicare Act). The provisions of the Medicare Act provide for a federal subsidy for plans that provide prescription drug benefits and meet certain qualifications, and alternatively would allow prescription drug plan sponsors to co-ordinate with the Medicare benefit. The Group reflected the impact of the legislation by reducing its actuarially determined obligation for postretirement benefits at December 31, 2004 and will reduce the net cost for postretirement benefits in subsequent periods. The $577 million reduction in liability was reflected as an actuarial gain (assumption change).

Inventory: In November 2004, the FASB issued Statement of Financial Accounting Standards No. 151 'Inventory Costs an amendment of ARB No. 43, Chapter 4' (SFAS 151). SFAS 151 requires that items, such as idle facility expense, excessive spoilage, double freight and re-handling costs, be recognized as current-period charges. SFAS 151 also requires that the allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. SFAS 151 is effective for accounting periods beginning after June 15, 2005. The adoption of SFAS 151 is not expected to have a significant effect on profit, as adjusted to accord with US GAAP, or BP shareholders' interest, as adjusted to accord with US GAAP.

Discontinued operations: In November 2004, the EITF reached a consensus on Issue No. 03-13 'Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations' (EITF 03-13). Under EITF 03-13, a disposed component of an enterprise is classified as a discontinued operation only where the ongoing entity has no continuing direct cash flows and does not retain an interest, contract or other arrangement sufficient to enable the entity to exert significant influence over the disposed component's operating and financial policies after disposal. EITF 03-13 is effective for a component of an enterprise that is either disposed of or classified as held for sale in accounting periods beginning after December 15, 2004.

Revenue: In November 2004, the EITF began discussion of Issue No. 04-13 'Accounting for Purchases and Sales of Inventory with the Same Counterparty' (EITF 04-13). EITF 04-13 addresses accounting issues that arise when a company both sells inventory to and buys inventory from another entity in the same line of business. The purchase and sale transactions may be pursuant to a single contractual arrangement or separate contractual arrangements and the inventory purchased or sold may be in the form of raw material, work-in-process or finished goods. At issue is whether the revenue, inventory cost and cost of sales should be recorded at fair value or whether the transactions should be classified as nonmonetary transactions. The EITF, which did not reach a consensus on the issue, requested the FASB staff to further explore the alternative views.

Practice within the oil and natural gas industry varies for buy/sell arrangements with common counterparties and physical exchanges. The Group accounts for buy/sell arrangements and physical exchanges on a net basis.

Nonmonetary asset exchanges: In December 2004, the FASB issued Statement of Financial Accounting Standards No. 153 'Exchanges of Nonmonetary Assets an amendment of APB Opinion No. 29' (SFAS 153). SFAS 153 eliminates the Accounting Principles Board Opinion No. 29 exception for nonmonetary exchanges of similar productive assets and replaces it with an exception for exchanges of nonmonetary assets that do not have commercial substance. SFAS 153 is effective for nonmonetary asset exchanges occurring in accounting periods beginning after June 15, 2005. The Group adopted SFAS 153 with effect from January 1, 2005. The adoption of SFAS 153 did not have a significant effect on profit, as adjusted to accord with US GAAP, or BP shareholders' interest, as adjusted to accord with US GAAP.

Share options: In December 2004, the FASB issued Statement of Financial Accounting Standards No. 123 (revised 2004) 'Share-Based Payment' (SFAS 123R). SFAS 123R, which is a revision of Statement of Financial Accounting Standards No. 123 'Accounting for Stock-Based Compensation' (SFAS 123), supersedes APB Opinion No. 25 'Accounting for Stock Issued to Employees'. Under SFAS 123R, share-based payments to employees and others are required to be recognized in the income statement based on their fair value. Pro forma disclosure is no longer a permitted alternative. SFAS 123R must be adopted no later than July 1, 2005.

The Group currently accounts for share-based employee compensation based on the intrinsic value method and, as such, generally recognizes no compensation cost for employee share options. Disclosure of the pro forma effect on net income and earnings per share if the Group had applied the fair value recognition provisions of SFAS 123 to share-based employee compensation in prior years is included in Note 38.

Effective January 1, 2005, as part of the adoption of IFRS, the Group adopted International Financial Reporting Standard No. 2 'Share-based Payment' (IFRS 2). IFRS 2 requires the recognition of expense when goods or services are received from employees or others in consideration for equity instruments or amounts that are based on the value of an entity's equity instruments. The recognition and measurement provisions of IFRS 2 are similar to those of SFAS 123R.

In adopting IFRS 2, the Group elected to restate prior years to recognize the expense associated with equity-settled share-based payment transactions that were not fully vested as of January 1, 2003 and the liability associated with cash-settled share-based payment transactions as of January 1, 2003.

The Group adopted SFAS 123R with effect from January 1, 2005. Had the Group adopted SFAS 123R in prior years, the impact would have approximated the pro forma expense included in Note 38.

Taxation: In December 2004, the FASB issued Staff Position No. 109-1 'Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004' (FSP 109-1). FSP 109-1, effective upon issuance, requires that the manufacturers' deduction provided for under the American Jobs Creation Act of 2004 (the Jobs Creation Act) be accounted for as a special deduction in accordance with FASB Statement of Financial Accounting Standards No. 109, 'Accounting for Income Taxes,' rather than a tax rate reduction. The manufacturers' deduction will be recognized by the Company in the year the benefit is earned.

In December 2004, the FASB issued Staff Position No. 109-2 'Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004' (FSP 109-2). The Jobs Creation Act provides a special one-time provision allowing earnings of certain non-US companies to be repatriated to a US parent company at a reduced tax rate. FSP 109-2, effective upon issuance, permits additional time beyond the financial reporting period of enactment in order to evaluate the effect of the Jobs Creation Act without undermining an entity's assertion that repatriation of non-US earnings to a US parent company is not expected within the foreseeable future. As provided by FSP 109-2, the Group has elected to defer a decision on potentially altering current plans regarding the permanent reinvestment in certain non-US subsidiaries and corporate joint ventures. The income tax effects associated with any repatriation of unremitted earnings as a result of the Jobs Creation Act cannot be reasonably estimated at this time.

Provisions: In March 2005, the FASB issued FASB Interpretation No. 47 'Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143' (Interpretation 47). Under Interpretation 47, a conditional asset retirement obligation represents an unconditional obligation to perform an asset retirement activity where the timing or method of settlement are conditional on a future event that may or may not be within the control of the entity. Interpretation 47 clarifies that an entity is required to recognize a liability, when incurred, for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional asset retirement obligation is factored into the measurement of the liability when sufficient information exists. SFAS 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation. Interpretation 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. Interpretation 47 is effective for fiscal years ending after December 15, 2005. The Group has not yet completed its evaluation of the impact of adopting Interpretation 47 on the Group's profit, as adjusted to accord with US GAAP, or BP shareholders' interest, as adjusted to accord with US GAAP.

Fixed assets: FASB Statement of Financial Accounting Standards No. 19 'Financial Accounting and Reporting by Oil and Gas Producing Companies' (SFAS 19) requires the cost of drilling an exploratory well (exploration or exploratory-type stratigraphic test wells) to be capitalized pending determination of whether the well has found proved reserves. If this determination cannot be made at the conclusion of drilling, SFAS 19 sets out additional requirements for continuing to carry the cost of the well as an asset. These requirements include firm plans for further drilling and a one-year time limitation on continued capitalization in certain situations. Subsequent to the issuance of SFAS 19, as a result of the increasing complexity of oil and gas projects due to drilling in remote and deepwater offshore locations, entities increasingly require more than one year to complete all of the activities that permit recognition of proved reserves. In addition, because of new technologies, in certain situations additional exploratory wells may no longer be required before a project can commence.

In April 2005, the FASB issued Staff Position No. 19-1 'Accounting for Suspended Well Costs' (FSP 19-1). FSP 19-1 amends SFAS 19 to permit the continued capitalization of exploratory well costs beyond one year if (a) the well found a sufficient quantity of reserves to justify its completion as a producing well and (b) the entity is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met, or if an entity obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well is assumed to be impaired, and its costs, net of any salvage value, is charged to expense. FSP 19-1 provides a number of indicators that would be considered in order to demonstrate that sufficient progress was being made in assessing the reserves and the economic viability of the project. FSP 19-1 is effective for accounting periods beginning after April 4, 2005. Early application of the guidance is permitted in periods for which financial statements have not yet been issued.

BP's accounting policy is that costs directly associated with an exploration well are capitalized as an intangible asset until the drilling of the well is complete and the results have been evaluated. If hydrocarbons are found, and, subject to further appraisal activity which may include the drilling of further wells (exploration or exploratory-type stratigraphic test wells), are likely to be capable of commercial development, the costs continue to be carried as an asset. All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off. When proved reserves of oil and natural gas are determined and development is sanctioned, the relevant expenditure is transferred to tangible production assets. We have adopted the FSP with effect from January 1, 2004. No previously capitalized costs were expensed upon the adoption of the FSP.

Accounting changes and error corrections: In May 2005, the FASB issued Statement of Financial Accounting Standards No. 154 'Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3' (SFAS 154). SFAS 154 applies to all voluntary changes in accounting principle and changes the requirements for the accounting for and reporting of a change in accounting principle. SFAS 154 requires retrospective application to prior period financial statements of a voluntary change in accounting principle unless it is impracticable. Previously, most voluntary changes in accounting principle were recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. SFAS 154 also requires that a change in the method of depreciation, amortization or depletion for long-lived nonfinancial assets be accounted for as a change in accounting estimate that is effected by a change in accounting principle. Previously, such changes were reported as a change in accounting principle. SFAS 154 is effective for accounting changes and corrections of errors made in accounting periods beginning after December 15, 2005. The adoption of SFAS 154 is not expected to have a significant effect on profit, as adjusted to accord with US GAAP, or BP shareholders' interest, as adjusted to accord with US GAAP.

Impact of new UK Accounting Standards adopted in 2004

In December 2000, the UK Accounting Standards Board issued Financial Reporting Standard No. 17 'Retirement Benefits' (FRS 17). This standard was to be fully effective for accounting periods ending on or after June 22, 2003 with certain of the disclosure requirements effective for periods prior to 2003. However, in November 2002, the UK Accounting Standards Board issued an amendment to FRS 17, which allows deferral of full adoption no later than January 1, 2005; although the disclosure requirements apply to periods prior to 2005. 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.

With effect from January 1, 2004, BP has fully adopted FRS 17. This change in accounting policy results in a prior year adjustment. Upon adoption, shareholders' interest at January 1, 2002 has been reduced by $132 million, profit for the years ended December 31, 2002 and 2003 have been (decreased) increased by $(50) million and $215 million, respectively, and total recognized gains and losses relating to the years ended December 31, 2002 and 2003 have been (decreased) increased by $(5,469) million and $78 million, respectively.

In addition, with effect from January 1, 2004 BP has also changed its accounting policy for shares held in employee share ownership plans for the benefit of employee share schemes.

Urgent Issues Task Force Abstract No. 38 'Accounting for Employee Share Ownership Plan (ESOP) trusts' (Abstract 38) changes the presentation of an entity's own shares held in an ESOP trust from requiring them to be recognized as assets to requiring them to be deducted in arriving at shareholders' funds. Transactions in an entity's own shares by an ESOP trust are similarly recorded as changes in shareholders' funds and do not give rise to gains or losses. This treatment is in line with the accounting for purchases and sales of own shares set out in Urgent Issues Task Force Abstract No. 37 'Purchases and Sales of Own Shares' (Abstract 37).

Abstract 37 requires a holding of an entity's own shares to be accounted for as a deduction in arriving at shareholders' funds, rather than being recorded as assets. Transactions in an entity's own shares are similarly recorded as changes in shareholders' funds and do not give rise to gains or losses. Abstract 37 applies where a company purchases treasury shares under new legislation that came into effect in December 2003.

Urgent Issues Task Force Abstract No. 17 'Employee share schemes' (Abstract 17) was amended by Abstract 38 to reflect the consequences for the profit and loss account of the changes in the presentation of an entity's own shares held by an ESOP trust. Amended Abstract 17 requires that the minimum expense should be the difference between the fair value of the shares at the date of award and the amount that an employee may be required to pay for the shares (i.e. the 'intrinsic value' of the award). The expense was previously determined either as the intrinsic value or, where purchases of shares had been made by an ESOP trust at fair value, by reference to the cost or book value of shares that were available for the award. The effect of adopting Abstract 17 is to reduce BP shareholders' interest at January 1, 2002 by $18 million; the impact on profit before taxation for the years ended December 31, 2002 and 2003 is negligible.

Impact of International Accounting Standards

An 'International Accounting Standards Regulation' was adopted by the Council of the European Union (EU) in June 2002. This regulation requires all EU companies listed on an EU stock exchange to use 'endorsed' International Financial Reporting Standards (IFRS), published by the International Accounting Standards Board (IASB), to report their consolidated results with effect from 1 January 2005. The IASB completed its development of IFRS to be adopted in 2005 during the first half of 2004, but has also published certain amendments and interpretations of IFRS which would be available for early adoption if endorsed by the EU.

The process of endorsement of IFRS by the EU to allow adoption by companies in 2005 is well advanced but not yet complete.

BP's project team includes a broadly based representation from across the Group designed to plan for and achieve a smooth transition to IFRS. The project team has examined all implementation aspects, including changes to accounting policies, the presentation of the Group's results, systems impacts and the wider business issues that may arise from such a fundamental change. The Group has reported its results from the first quarter of 2005 using IFRS. However, the implementation may still be affected by developments in the IASB's standard-setting process and the endorsement of standards and interpretations by the EU.

The Group has decided that, for the purposes of the restatement of prior periods currently reported under UK GAAP, the date of transition to IFRS is January 1, 2003. However, in accordance with the provisions of IFRS 1, the date of adoption of International Accounting Standards Nos. 32 and 39, which deal with the recognition and presentation of financial instruments, is set at January 1, 2005, with no restatement of prior periods' results.

The process of finalizing the restatements of the results and financial position for 2003 and 2004 under IFRS, was completed in March 2005. The major effects of changing from current accounting practice to IFRS are in the following areas: goodwill acquired in a business combination; deferred tax related to business combinations and in respect of the valuation of stocks; accounting for items falling within the scope of IAS Nos. 32 and 39, including embedded derivatives and hedge accounting; the treatment of major overhaul expenditure; exchanges of fixed assets; recognition of dividend liabilities; and share-based payments. Certain joint arrangements with third parties, where BP currently accounts for its share of individual assets, liabilities, income and expense, will be accounted for using the equity method, resulting in reclassifications within the income statement and balance sheet.

The adoption of IFRS, subject to developments in the standard-setting process and the endorsement of standards and interpretations, resulted in a $1,344 million and $1,966 million increase in profit for the years ended December 31, 2004 and 2003, respectively, and a $236 million increase in BP shareholders' interest at December 31, 2004.

Note 51 Condensed consolidating information on certain US Subsidiaries

BP p.l.c. 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., 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 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 Exploration (Alaska) Inc. and other subsidiaries.

Income statement

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
			($ million)		
Year ended December 31, 2004					
Turnover	3,811		294,849	(3,811)	294,849
Less: Joint ventures			9,790		9,790
Group turnover	3,811		285,059	(3,811)	285,059
Cost of sales	1,439		249,601	(3,930)	247,110
Production taxes	267		1,882		2,149
Gross profit	2,105		33,576	119	35,800
Distribution and administration expenses	3	1,302	13,683		14,988
Exploration expense	4		633		637
	2,098	(1,302)	19,260	119	20,175
Other income	23	1,296	715	(1,359)	675
Group operating profit	2,121	(6)	19,975	(1,240)	20,850
Share of profits of joint ventures			2,943		2,943
Share of profits of associated undertakings			634		634
Equity-accounted income of subsidiaries	707	25,444		(26,151)	
Total operating profit	2,828	25,438	23,552	(27,391)	24,427
Profit (loss) on sale of businesses or termination of operations		(695)	(695)	695	(695)
Profit (loss) on sale of fixed assets		1,510	1,510	(1,510)	1,510
Profit before interest and tax	2,828	26,253	24,367	(28,206)	25,242
Interest expense	43	1,883	1,901	(3,185)	642
Other finance expense	16	357	693	(709)	357
Profit before taxation	2,769	24,013	21,773	(24,312)	24,243
Taxation	937	8,282	7,683	(8,620)	8,282
Profit after taxation	1,832	15,731	14,090	(15,692)	15,961
Minority shareholders' interest			230		230
Profit for the year	1,832	15,731	13,860	(15,692)	15,731

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	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
			($ million)		
Year ended December 31, 2004					
Profit as reported	1,832	15,731	13,860	(15,692)	15,731
Adjustments:					
Deferred taxation/business combinations	(11)	(591)	(580)	591	(591)
Provisions	(1)	(140)	(138)	139	(140)
Oil and natural gas reserve differences		30	30	(30)	30
Sale and leaseback		(6)	(6)	6	(6)
Goodwill and intangible assets		1,436	1,436	(1,436)	1,436
Derivative financial instruments		(175)	(175)	175	(175)
Gain arising on asset exchange		(68)	(68)	68	(68)
Pensions and other postretirement benefits		(47)	(70)	70	(47)
Impairments		677	677	(677)	677
Provisions for severance and operating costs		60	60	(60)	60
Equity-accounted investments		226	226	(226)	226
Other		(43)	(43)	43	(43)
Profit for the year as adjusted to accord with US GAAP	1,820	17,090	15,209	(17,029)	17,090

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
			($ million)		
Year ended December 31, 2003					
Turnover	3,168		236,045	(3,168)	236,045
Less: Joint ventures			3,474		3,474
Group turnover	3,168		232,571	(3,168)	232,571
Cost of sales	1,436		203,168	(3,269)	201,335
Production taxes	242		1,481		1,723
Gross profit	1,490		27,922	101	29,513
Distribution and administration expenses	4	671	13,397		14,072
Exploration expense	14		528		542
	1,472	(671)	13,997	101	14,899
Other income	21	1,413	291	(939)	786
Group operating profit	1,493	742	14,288	(838)	15,685
Share of profits of joint ventures			924		924
Share of profits of associated undertakings.			514		514
Equity-accounted income of subsidiaries	420	17,049		(17,469)	
Total operating profit	1,913	17,791	15,726	(18,307)	17,123
Profit (loss) on sale of businesses or termination of operations		(13)	(28)	13	(28)
Profit (loss) on sale of fixed assets	(1)	859	860	(859)	859
Profit before interest and tax	1,912	18,637	16,558	(19,153)	17,954
Interest expense	288	1,482	1,325	(2,451)	644
Other finance expense	11	547	740	(751)	547
Profit before taxation	1,613	16,608	14,493	(15,951)	16,763
Taxation	741	6,111	5,449	(6,190)	6,111
Profit after taxation	872	10,497	9,044	(9,761)	10,652
Minority shareholders' interest			170		170
Profit for the year	872	10,497	8,874	(9,761)	10,482

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	Guarantor			
	BP Exploration (Alaska) Inc	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP Group**
			($ million)		
Year ended December 31, 2003					
Profit as reported	872	10,497	8,874	(9,761)	10,482
Adjustments:					
Deferred taxation/business combinations	(12)	(169)	(149)	161	(169)
Provisions	(5)	49	90	(85)	49
Revisions to fair market values		289	289	(289)	289
Sale and leaseback		69	69	(69)	69
Goodwill and intangible assets		1,376	1,376	(1,376)	1,376
Derivative financial instruments	(13)	12	12	1	12
Gain arising on asset exchange		(17)	(17)	17	(17)
Pensions and other postretirement benefits		(215)	(583)	583	(215)
Other		13	13	(13)	13
Profit for the year before cumulative effect of accounting changes as adjusted to accord with US GAAP	842	11,904	9,974	(10,831)	11,889
Cumulative effect of accounting changes:					
Provisions	221	1,002	788	(1,009)	1,002
Derivative financial instruments		50	50	(50)	50
Profit for the year as adjusted to accord with US GAAP	1,063	12,956	10,812	(11,890)	12,941

	Issuer: BP Exploration (Alaska) Inc	Guarantor: BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
			($ million)		
Year ended December 31, 2002					
Turnover	2,356		180,122	(2,292)	180,186
Less: Joint ventures			1,465		1,465
Group turnover	2,356		178,657	(2,292)	178,721
Cost of sales	1,450		155,603	(2,438)	154,615
Production taxes	199		1,075		1,274
Gross profit	707		21,979	146	22,832
Distribution and administration expenses	12	1,025	11,595		12,632
Exploration expense	34		610		644
	661	(1,025)	9,774	146	9,556
Other income	31	752	446	(588)	641
Group operating profit	692	(273)	10,220	(442)	10,197
Share of profits of joint ventures			347		347
Share of profits of associated undertakings.			617		617
Equity-accounted income of subsidiaries	299	11,790		(12,089)	
Total operating profit	991	11,517	11,184	(12,531)	11,161
Profit (loss) on sale of businesses or termination of operations		884	(33)	(884)	(33)
Profit (loss) on sale of fixed assets	(4)	1,226	1,205	(1,226)	1,201
Profit before interest and tax	987	13,627	12,356	(14,641)	12,329
Interest expense	83	1,500	1,400	(1,916)	1,067
Other finance expense	10	73	483	(493)	73
Profit before taxation	894	12,054	10,473	(12,232)	11,189
Taxation	344	4,317	4,040	(4,384)	4,317
Profit after taxation	550	7,737	6,433	(7,848)	6,872
Minority shareholders' interest			77		77
Profit for the year	550	7,737	6,356	(7,848)	6,795

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	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
			($ million)		
Year ended December 31, 2002					
Profit as reported	550	7,737	6,356	(7,848)	6,795
Adjustments:					
Deferred taxation/business combinations	(129)	(603)	(520)	649	(603)
Provisions	(1)	8	9	(8)	8
Sale and leaseback		24	24	(24)	24
Goodwill and intangible assets		1,302	1,302	(1,302)	1,302
Derivative financial instruments	(50)	540	540	(490)	540
Gain arising on asset exchange		(18)	(18)	18	(18)
Pensions and other postretirement benefits		50	442	(442)	50
Other		11	11	(11)	11
Profit for the year as adjusted to accord with US GAAP	370	9,051	8,146	(9,458)	8,109

Note 51 Condensed consolidating information on certain US Subsidiaries (continued)

Balance sheet

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
			($ million)		
At December 31, 2004					
Fixed assets					
Intangible assets	418		11,658		12,076
Tangible assets	6,326		90,422		96,748
Investments					
Subsidiaries equity-accounted basis	3,069	108,670		(111,739)	
Other		2	18,404		18,406
	3,069	108,672	18,404	(111,739)	18,406
Total fixed assets	9,813	108,672	120,484	(111,739)	127,230
Current assets					
Inventories	107		15,591		15,698
Receivables amounts falling due:					
Within one year	7,644	791	51,095	(15,135)	44,395
After more than one year	5,244	1,451	5,151	(9,545)	2,301
Investments			328		328
Cash at bank and in hand	(1)	4	1,153		1,156
	12,994	2,246	73,318	(24,680)	63,878
Current liabilities amounts falling due within one year					
Finance debt	57		10,127		10,184
Other payables	1,635	9,508	58,333	(15,135)	54,341
Net current assets (liabilities)	11,302	(7,262)	4,858	(9,545)	(647)
Total assets less current liabilities	21,115	101,410	125,342	(121,284)	126,583
Noncurrent liabilities					
Finance debt			12,907		12,907
Other payables	4,263	76	9,711	(9,545)	4,505
Provisions for liabilities and charges					
Deferred taxation	1,745		13,305		15,050
Other	549		9,059		9,608
Net assets excluding pension and other postretirement benefit balances	14,558	101,334	80,360	(111,739)	84,513
Defined benefit pension plan surpluses		1,465	10		1,475
Defined benefit pension plan deficits	81		5,782		5,863
Other postretirement benefit plan deficit			2,126		2,126
Net assets	14,477	102,799	72,462	(111,739)	77,999
Minority shareholders' interest equity			1,343		1,343

	Issuer	Guarantor			
BP Shareholders' interest	14,477	102,799	71,119	(111,739)	76,656

At December 31, 2004					
Capital and reserves					
Capital shares	3,353	5,403		(3,353)	5,403
Paid in surplus	3,145	6,366		(3,145)	6,366
Merger reserve		26,465	697		27,162
Other reserves		44			44
Shares held by ESOP trusts		(82)			(82)
Retained earnings	7,979	64,603	70,422	(105,241)	37,763
	14,477	102,799	71,119	(111,739)	76,656

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	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
			($ million)		
At December 31, 2004					
BP Shareholders' interest as reported	14,477	102,799	71,119	(111,739)	76,656
Adjustments:					
Deferred taxation/business combinations	51	(1,533)	(1,584)	1,533	(1,533)
Provisions	26	(137)	(162)	136	(137)
Oil and natural gas reserve differences		30	30	(30)	30
Sale and leaseback		(43)	(43)	43	(43)
Goodwill and intangible assets		3,207	3,207	(3,207)	3,207
Derivative financial instruments	(63)	(250)	(250)	313	(250)
Gain arising on asset exchange		61	61	(61)	61
Pensions and other postretirement benefits	82	4,089	1,017	(1,099)	4,089
Impairments		677	677	(677)	677
Provisions for severance and operating costs		60	60	(60)	60
Equity-accounted investments		226	226	(226)	226
Dividends		1,822	1,822	(1,822)	1,822
Investments		227	227	(227)	227
Other					
BP Shareholders' interest as adjusted to accord with US GAAP	14,573	111,235	76,407	(117,123)	85,092

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
			($ million)		
At December 31, 2003					
Fixed assets					
Intangible assets	424		13,218		13,642
Tangible assets	6,432		85,479		91,911
Investments					
Subsidiaries equity-accounted basis	2,814	83,123		(85,937)	
Other		2	17,456		17,458
	2,814	83,125	17,456	(85,937)	17,458
Total fixed assets	9,670	83,125	116,153	(85,937)	123,011
Current assets					
Inventories	102		11,515		11,617
Receivables amounts falling due:					
Within one year	9,782	865	36,272	(15,535)	31,384
After more than one year	1,368	23,751	6,753	(29,354)	2,518
Investments			185		185
Cash at bank and in hand	(5)	3	1,949		1,947
	11,247	24,619	56,674	(44,889)	47,651
Current liabilities amounts falling due within one year					
Finance debt	55		9,401		9,456
Other payables	1,541	6,802	48,320	(15,535)	41,128
Net current assets (liabilities)	9,651	17,817	(1,047)	(29,354)	(2,933)
Total assets less current liabilities	19,321	100,942	115,106	(115,291)	120,078
Noncurrent liabilities					
Finance debt			12,869		12,869
Other payables	4,272	50	31,062	(29,354)	6,030
Provisions for liabilities and charges					
Deferred taxation	1,745		12,626		14,371
Other	505		8,094		8,599
Net assets excluding pension and other postretirement benefit balances	12,799	100,892	50,455	(85,937)	78,209
Defined benefit pension plan surpluses		1,093	53		1,146
Defined benefit pension plan deficits	82		4,923		5,005
Other postretirement benefit plan deficit			2,630		2,630
Net assets	12,717	101,985	42,955	(85,937)	71,720
Minority shareholders' interest equity			1,125		1,125
BP Shareholders' interest	12,717	101,985	41,830	(85,937)	70,595

Issuer				

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
			($ million)		
At December 31, 2003					
Capital and reserves					
Capital shares	1,903	5,552		(1,903)	5,552
Paid in surplus	3,145	4,480		(3,145)	4,480
Merger reserve		26,380	697		27,077
Other reserves		129			129
Shares held by ESOP trusts		(96)			(96)
Retained earnings	7,669	65,540	41,133	(80,889)	33,453
	12,717	101,985	41,830	(85,937)	70,595

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	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
			($ million)		
BP Shareholders' interest as reported	12,717	101,985	41,830	(85,937)	70,595
Adjustments:					
Deferred taxation/business combinations	62	(938)	(1,000)	938	(938)
Provisions	27	(128)	(155)	128	(128)
Sale and leaseback		(37)	(37)	37	(37)
Goodwill and intangible assets		1,669	1,669	(1,669)	1,669
Derivative financial instruments	(63)	(72)	(9)	72	(72)
Gain arising on asset exchange		129	129	(129)	129
Pension and other postretirement benefits	82	5,246	3,688	(3,770)	5,246
Dividends		1,495			1,495
Investments		1,251	1,251	(1,251)	1,251
Other		(43)	(43)	43	(43)
BP Shareholders' interest as adjusted to accord with US GAAP	12,825	110,557	47,323	(91,538)	79,167

Cash flow statement

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
			($ million)		
Year ended December 31, 2004					
Net cash inflow (outflow) from operating activities	2,593	24,947	331	683	28,554
Dividends from joint ventures			1,908		1,908
Dividends from associated undertakings			291		291
Dividends from subsidiaries	16	18,489		(18,505)	
Net cash inflow (outflow) from servicing of finance and returns on investments	(61)	1,391	(989)	(683)	(342)
Tax paid	(142)	(60)	(6,176)		(6,378)
Net cash inflow (outflow) for capital expenditure and financial investment	(364)	(31,517)	23,169		(8,712)
Net cash inflow (outflow) for acquisitions and disposals			(3,242)		(3,242)
Equity dividends paid		(6,041)	(18,505)	18,505	(6,041)
Net cash inflow (outflow)	2,042	7,209	(3,213)		6,038
Financing	2,038	7,208	(2,469)		6,777
Management of liquid resources			132		132
Increase (decrease) in cash	4	1	(876)		(871)
	2,042	7,209	(3,213)		6,038

The consolidated statement of cash flows presented in accordance with SFAS 95 is as follows:

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
			($ million)		
Net cash provided by (used in) operating activities	2,467	44,767	(4,635)	(18,325)	24,274
Net cash provided by (used in) investing activities	(364)	(31,517)	19,927	(208)	(12,162)
Net cash provided by (used in) financing activities	(2,099)	(13,249)	(16,036)	18,533	(12,851)
Currency translation differences relating to cash and cash equivalents			91		91
Increase (decrease) in cash and cash equivalents	4	1	(653)		(648)
Cash and cash equivalents at beginning of year	(5)	3	2,134		2,132
Cash and cash equivalents at end of year	(1)	4	1,481		1,484

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
			($ million)		
Year ended December 31, 2003					
Net cash inflow (outflow) from operating activities	1,774	(16,970)	36,877	17	21,698
Dividends from joint ventures			131		131
Dividends from associated undertakings			417		417
Dividends from subsidiaries	18	27,914		(27,932)	
Net cash inflow (outflow) from servicing of finance and returns on investments	(58)	578	(1,231)		(711)
Tax paid	(104)	(6)	(4,694)		(4,804)
Net cash inflow (outflow) for capital expenditure and financial investment	(389)	(4,051)	(1,684)		(6,124)
Net cash outflow for acquisitions and disposals	8	17	(3,556)	(17)	(3,548)
Equity dividends paid		(5,654)	(27,932)	27,932	(5,654)
Net cash inflow (outflow)	1,249	1,828	(1,672)		1,405
Financing	1,243	1,826	(1,940)		1,129
Management of liquid resources			(41)		(41)
Increase (decrease) in cash	6	2	309		317
	1,249	1,828	(1,672)		1,405

The consolidated statement of cash flows presented in accordance with SFAS 95 is as follows:

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP Group**
			($ million)		
Net cash provided by (used in) operating activities	1,687	11,517	31,500	(27,763)	16,941
Net cash provided by (used in) investing activities	(381)	(4,034)	(5,240)	(207)	(9,862)
Net cash provided by (used in) financing activities	(1,300)	(7,481)	(25,992)	27,970	(6,803)
Currency translation differences relating to cash and cash equivalents			121		121
Increase (decrease) in cash and cash equivalents	6	2	389		397
Cash and cash equivalents at beginning of year	(11)	1	1,745		1,735
Cash and cash equivalents at end of year	(5)	3	2,134		2,132

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
			($ million)		
Year ended December 31, 2002					
Net cash inflow (outflow) from operating activities	1,357	9,108	13,308	(4,431)	19,342
Dividends from joint ventures			198		198
Dividends from associated undertakings			368		368
Dividends from subsidiaries	26	761		(787)	
Net cash inflow (outflow) from servicing of finance and returns on investments	(28)	235	(1,118)		(911)
Tax paid	(75)	(2)	(3,017)		(3,094)
Net cash inflow (outflow) for capital expenditure and financial investment	(1,097)	169	(8,700)		(9,628)
Net cash outflow for acquisitions and disposals		(4,431)	(1,337)	4,431	(1,337)
Equity dividends paid		(5,264)	(787)	787	(5,264)
Net cash inflow (outflow)	183	576	(1,085)		(326)
Financing	165	578	(906)		(163)
Management of liquid resources			(220)		(220)
Increase (decrease) in cash	18	(2)	41		57
	183	576	(1,085)		(326)

The consolidated statement of cash flows presented in accordance with SFAS 95 is as follows:

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
			($ million)		
Net cash provided by (used in) operating activities	1,307	10,102	9,753	(5,119)	16,043
Net cash provided by (used in) investing activities	(1,097)	(4,261)	(10,052)	4,345	(11,065)
Net cash provided by (used in) financing activities	(192)	(5,843)	120	774	(5,141)
Currency translation differences relating to cash and cash equivalents			90		90
Increase (decrease) in cash and cash equivalents	18	(2)	(89)		(73)
Cash and cash equivalents at beginning of year	(29)	3	1,834		1,808
Cash and cash equivalents at end of year	(11)	1	1,745		1,735

Note 52 Post balance sheet events

In December 2005, BP sold Innovene, its olefins, derivatives and refining group, to INEOS. Gross proceeds received initially amounted to $8,477 million, which is subject to revision for closing adjustments. There were selling costs of $120 million. A loss before tax of $694 million was recognized on the remeasurement to fair value less costs to sell of the Innovene operations.

BP announced in April 2006 the sale of its remaining Gulf of Mexico Shelf exploration and production interests for $1.3 billion. The transaction is expected to close later in 2006. The gain on the sale is expected to be about $0.5 billion.

BP p.l.c. AND SUBSIDIARIES

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, 2004, 2003 and 2002.

Movements in estimated net proved reserves of crude oil (a)(b)

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
					(millions of barrels)				
2004									
Subsidiary undertakings									
At January 1									
Developed	697	236	1,902	385	82	190		73	3,565
Undeveloped	245	127	1,499	354	81	632		711	3,649
	942	363	3,401	739	163	822		784	7,214
Changes attributable to:									
Revisions of previous estimates	(133)	1	(44)	(92)	2	19		(192)	(439)
Purchases of reserves-in-place									
Extensions, discoveries and other additions	24		74	5	8	48		213	372
Improved recovery	57	4	55	31		6		3	156
Production	(121)	(28)	(217)	(63)	(17)	(48)		(21)	(515)
Sales of reserves-in-place			(17)	(10)	(6)				(33)
	(173)	(23)	(149)	(129)	(13)	25		3	(459)
At December 31 (c)									
Developed	559	231	2,041	311	65	204		62	3,473
Undeveloped	210	109	1,211	299	85	643		725	3,282
	769	340	3,252(d)	610	150	847		787	6,755
Equity-accounted entities (BP share)									
At January 1									
Developed				206	1		1,384	705	2,296
Undeveloped				134			410	27	571
				340	1		1,794	732	2,867
Changes attributable to:									
Revisions of previous estimates				(5)			382	15	392
Purchases of reserves-in-place							252		252
Extensions, discoveries and other additions				2					2
Improved recovery				17			37		54

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Production				(25)			(304)	(55)	(384)
Sales of reserves-in-place							(4)		(4)
				(11)			363	(40)	312
At December 31 (e)									
Developed				204	1		1,863	592	2,660
Undeveloped				125			294	100	519
				329	1		2,157	692	3,179

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
				(millions of barrels)					
2003									
Subsidiary undertakings									
At January 1									
Developed	858	250	2,225	573	125	179		125	4,335
Undeveloped	269	99	1,336	198	54	723		748	3,427
	1,127	349	3,561	771	179	902		873	7,762
Changes attributable to:									
Revisions of previous estimates	53	42	(83)	(33)	30	(253)		(107)	(351)
Purchases of reserves-in-place				42					42
Extensions, discoveries and other additions	6	16	240	1		361		36	660
Improved recovery	38	5	84	42				3	172
Production	(138)	(30)	(237)	(71)	(22)	(43)		(21)	(562)
Sales of reserves-in-place	(144)	(19)	(164)	(13)	(24)	(145)			(509)
	(185)	14	(160)	(32)	(16)	(80)		(89)	(548)
At December 31 (c)									
Developed	697	236	1,902	385	82	190		73	3,565
Undeveloped	245	127	1,499	354	81	632		711	3,649
	942	363	3,401(d)	739	163	822		784	7,214
Equity-accounted entities (BP share)									
At January 1									
Developed				173	1		252	752	1,178
Undeveloped				139	6		49	31	225
				312	7		301	783	1,403
Changes attributable to:									
Revisions of previous estimates				3				2	5
Purchases of reserves-in-place							1,600		1,600
Extensions, discoveries and other additions				6					6
Improved recovery				42					42
Production				(23)	(1)		(107)	(53)	(184)
Sales of reserves-in-place					(5)				(5)
				28	(6)		1,493	(51)	1,464
At December 31 (e)									
Developed				206	1		1,384	705	2,296
Undeveloped				134			410	27	571
				340	1		1,794	732	2,867

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
				(millions of barrels)					
2002									
Subsidiary undertakings									
At January 1									
Developed	1,008	269	2,195	401	113	200		122	4,308
Undeveloped	317	112	1,394	195	52	458		381	2,909
	1,325	381	3,589	596	165	658		503	7,217
Changes attributable to:									
Revisions of previous estimates	(58)		(33)	(28)	36	27		27	(29)
Purchases of reserves-in-place	8	2		210				7	227
Extensions, discoveries and other additions	9		199	39		263		347	857
Improved recovery	19	4	60	20	5			24	132
Production	(168)	(38)	(254)	(65)	(27)	(46)		(21)	(619)
Sales of reserves-in-place	(8)			(1)				(14)	(23)
	(198)	(32)	(28)	175	14	244		370	545
At December 31 (c)									
Developed	858	250	2,225	573	125	179		125	4,335
Undeveloped	269	99	1,336	198	54	723		748	3,427
	1,127	349	3,561(d)	771	179	902		873	7,762
Equity-accounted entities (BP share)									
At January 1									
Developed	5			129	3		45	800	982
Undeveloped				146	6			25	177
	5			275	9		45	825	1,159
Changes attributable to:									
Revisions of previous estimates				(4)	(1)		80	1	76
Purchases of reserves-in-place							203		203
Extensions, discoveries and other additions				7					7
Improved recovery				55					55
Production				(21)	(1)		(27)	(43)	(92)
Sales of reserves-in-place	(5)								(5)
	(5)			37	(2)		256	(42)	244
At December 31									
Developed				173	1		252	752	1,178
Undeveloped				139	6		49	31	225
				312	7		301	783	1,403

(a) Crude oil includes natural gas liquids and condensate. Net proved reserves of crude oil exclude production royalties due to others, whether royalty is payable in cash or in kind.

(b) Proved reserves estimates for the years ended December 31, 2004 and 2003 reflect year-end prices and some adjustments which have been made vis-à-vis individual asset reserve estimates based on different applications of certain SEC interpretations of SEC regulations relating to the use of technology (mainly seismic) to estimate reserves in the reservoir away from wellbores and the reporting of fuel gas (i.e., gas used for fuel in operations on the lease) within proved reserves. Reserve estimates for the year ended December 31, 2002 have not been adjusted.

(c) Includes 40 million barrels of crude oil (55 million barrels at December 31, 2003 and 17 million barrels at December 31, 2002) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

(d) Proved reserves in the Prudhoe Bay field in Alaska include an estimated 77 million barrels (78 million barrels at December 31, 2003 and 86 million barrels at December 31, 2002) 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.

(e) Includes 127 million barrels (97 million barrels at December 31, 2003) in respect of the 5.9% minority interest in TNK-BP.

Movements in estimated net proved reserves of natural gas (a)(b)

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
				(billions of cubic feet)					
2004									
Subsidiary undertakings									
At January 1									
Developed	2,996	262	11,482	4,212	1,976	640		255	21,823
Undeveloped	1,095	1,255	3,337	11,531	3,026	2,188		900	23,332
	4,091	1,517	14,819	15,743	5,002	2,828		1,155	45,155
Changes attributable to:									
Revisions of previous estimates	(210)	28	(438)	(1,081)	106	16		558	(1,021)
Purchases of reserves-in-place			3	2					5
Extensions, discoveries and other additions	127		140	991	2,478	233		3	3,972
Improved recovery	134	4	870	76		29		38	1,151
Production (c)	(461)	(47)	(1,111)	(875)	(296)	(102)		(76)	(2,968)
Sales of reserves-in-place			(202)	(92)	(247)	(103)			(644)
	(410)	(15)	(738)	(979)	2,041	73		523	495
At December 31 (d)									
Developed	2,498	248	10,811	4,101	1,624	1,015		282	20,579
Undeveloped	1,183	1,254	3,270	10,663	5,419	1,886		1,396	25,071
	3,681	1,502	14,081	14,764	7,043	2,901		1,678	45,650
Equity-accounted entities (BP share)									
At January 1									
Developed				1,591	136		46	58	1,831
Undeveloped				916	80		14	28	1,038
				2,507	216		60	86	2,869
Changes attributable to:									
Revisions of previous estimates				(12)	(17)		341		312
Purchases of reserves-in-place									
Extensions, discoveries and other additions									
Improved recovery				23					23
Production (e)				(144)	(23)		(177)	(3)	(347)
Sales of reserves-in-place									
				(133)	(40)		164	(3)	(12)
At December 31 (f)									
Developed				1,397	107		214	60	1,778
Undeveloped				977	69		10	23	1,079
				2,374	176		224	83	2,857

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
				(billions of cubic feet)					
2003									
Subsidiary undertakings									
At January 1									
Developed	3,215	216	12,102	4,637	2,528	815		260	23,773
Undeveloped	651	44	2,259	13,128	2,747	3,176		66	22,071
	3,866	260	14,361	17,765	5,275	3,991		326	45,844
Changes attributable to:									
Revisions of previous estimates	537	119	205	(1,629)	10	158		111	(489)
Purchases of reserves-in-place			1	85					86
Extensions, discoveries and other additions	397	1,213	293	64				764	2,731
Improved recovery	72	1	2,083	262				28	2,446
Production (c)	(528)	(43)	(1,224)	(792)	(283)	(92)		(74)	(3,036)
Sales of reserves-in-place	(253)	(33)	(900)	(12)		(1,229)			(2,427)
	225	1,257	458	(2,022)	(273)	(1,163)		829	(689)
At December 31 (d)									
Developed	2,996	262	11,482	4,212	1,976	640		255	21,823
Undeveloped	1,095	1,255	3,337	11,531	3,026	2,188		900	23,332
	4,091	1,517	14,819	15,743	5,002	2,828		1,155	45,155
Equity-accounted entities (BP share)									
At January 1									
Developed				1,282	160			64	1,506
Undeveloped				855	538			46	1,439
				2,137	698			110	2,945
Changes attributable to:									
Revisions of previous estimates				437	26		107	(21)	549
Purchases of reserves-in-place									
Extensions, discoveries and other additions				12					12
Improved recovery				35					35
Production (e)				(114)	(26)		(47)	(3)	(190)
Sales of reserves-in-place					(482)				(482)
				370	(482)		60	(24)	(76)
At December 31									
Developed				1,591	136		46	58	1,831
Undeveloped				916	80		14	28	1,038
				2,507	216		60	86	2,869

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
				(billions of cubic feet)					
2002									
Subsidiary undertakings									
At January 1									
Developed	3,212	265	12,232	4,549	2,307	826		358	23,749
Undeveloped	1,160	43	2,535	9,926	2,220	3,209		117	19,210
	4,372	308	14,767	14,475	4,527	4,035		475	42,959
Changes attributable to:									
Revisions of previous estimates	(137)	3	(149)	30	1,061	38		46	892
Purchases of reserves-in-place	77	3	1	4				52	137
Extensions, discoveries and other additions	126		340	2,687		11		4	3,168
Improved recovery	64		738	1,263					2,065
Production (c)	(566)	(54)	(1,334)	(655)	(313)	(93)		(86)	(3,101)
Sales of reserves-in-place	(70)		(2)	(39)				(165)	(276)
	(506)	(48)	(406)	3,290	748	(44)		(149)	2,885
At December 31 (d)									
Developed	3,215	216	12,102	4,637	2,528	815		260	23,773
Undeveloped	651	44	2,259	13,128	2,747	3,176		66	22,071
	3,866	260	14,361	17,765	5,275	3,991		326	45,844
Equity-accounted entities (BP share)									
At January 1									
Developed	24			1,288	153			67	1,532
Undeveloped				1,158	491			35	1,684
	24			2,446	644			102	3,216
Changes attributable to:									
Revisions of previous estimates				(251)	82			12	(157)
Purchases of reserves-in-place				18			2		20
Extensions, discoveries and other additions				27					27
Improved recovery				1					1
Production (e)	(2)			(104)	(28)		(2)	(4)	(140)
Sales of reserves-in-place	(22)								(22)
	(24)			(309)	54			8	(271)
At December 31									
Developed				1,282	160			64	1,506
Undeveloped				855	538			46	1,439
				2,137	698			110	2,945

(a) Net proved reserves of natural gas exclude production royalties due to others, whether royalty is payable in cash or in kind.

(b) Proved reserves estimates for the years ended December 31, 2004 and 2003 reflect year-end prices and some adjustments which have been made vis-à-vis individual asset reserve estimates based on different applications of certain SEC interpretations of SEC regulations relating to the use of technology (mainly seismic) to estimate reserves in the reservoir away from wellbores and the reporting of fuel gas (i.e., gas used for fuel in operations on the lease) within proved reserves. Reserve estimates for the year ended December 31, 2002 have not been adjusted.

(c) Includes 165 billion cubic feet of natural gas consumed in operations (2003, 69 billion cubic feet and 2002, 63 billion cubic feet).

(d) Includes 4,064 billion cubic feet of natural gas (4,505 billion cubic feet at December 31, 2003 and 1.185 billion cubic feet at December 31, 2002) in respect of the 30% minority interest in BP Trinidad and Tobago LLC.

(e) Includes 25 billion cubic feet of natural gas consumed in operations (2003, nil and 2002, nil).

(f) Includes 13 billion cubic feet of natural gas at December 31, 2004 in respect of the 5.9% minority interest in TNK-BP.

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'.

In 2004 and 2003, the reserves reported in the Supplementary Oil and Gas Information and those included in the standardized measure of discounted future net cash flows (SMOG) are the same, both based on year-end prices. In prior years, the reserves reported at planning prices were adjusted for the purposes of the SMOG calculation to reflect only the impacts of the year-end price on PSAs, resulting in a lower volume being included in SMOG when prices were higher than our planning prices.

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 Americas	Asia Pacific	Africa	Russia	Others	Total
					($ million)				
At December 31, 2004									
Future cash inflows (a)	47,400	21,700	169,500	52,600	27,200	35,000		34,200	387,600
Future production cost (b)	19,200	4,500	37,800	14,300	6,700	5,800		6,900	95,200
Future development cost (b)	2,200	1,900	10,800	4,400	3,500	4,700		5,100	32,600
Future taxation (c)	9,900	11,200	41,800	16,300	5,200	6,900		5,000	96,300
Future net cash flows	16,100	4,100	79,100	17,600	11,800	17,600		17,200	163,500
10% annual discount (d)	4,700	2,000	38,100	8,000	6,900	7,500		7,800	75,000
Standardized measure of discounted future net cash flows (e)	11,400	2,100	41,000	9,600	4,900	10,100		9,400	88,500
At December 31, 2003									
Future cash inflows (a)	44,900	17,000	155,500	56,300	17,900	31,000		25,800	348,400
Future production cost (b)	16,200	3,900	29,600	14,200	4,400	4,700		5,400	78,400
Future development cost (b)	2,300	1,800	9,800	4,300	1,400	5,100		3,100	27,800
Future taxation (c)	10,200	7,600	41,400	17,100	3,600	5,300		3,800	89,000
Future net cash flows	16,200	3,700	74,700	20,700	8,500	15,900		13,500	153,200
10% annual discount (d)	5,300	1,900	36,200	10,500	4,100	7,700		7,000	72,700
Standardized measure of discounted future net cash flows (e)	10,900	1,800	38,500	10,200	4,400	8,200		6,500	80,500
At December 31, 2002									
Future cash inflows (a)	44,300	11,600	146,100	64,200	20,500	32,300		19,900	338,900
Future production cost (b)	16,100	3,100	29,700	15,100	5,000	5,000		4,000	78,000
Future development cost (b)	2,300	800	9,300	3,000	2,600	5,100		2,900	26,000
Future taxation (c)	9,800	5,300	38,500	22,700	4,000	4,500		3,200	88,000
Future net cash flows	16,100	2,400	68,600	23,400	8,900	17,700		9,800	146,900
10% annual discount (d)	4,800	800	33,100	12,400	4,800	9,600		4,900	70,400
Standardized measure of discounted future net cash flows (e)	11,300	1,600	35,500	11,000	4,100	8,100		4,900	76,500

The following are the principal sources of change in the standardized measure of discounted future net cash flows during the years ended December 31, 2004, 2003 and 2002:

	Years ended December 31,		
	2004	2003	2002
		($ million)	
Sales and transfers of oil and gas produced, net of production costs	(24,100)	(22,200)	(22,400)
Development costs incurred during the year	6,300	6,300	7,200
Extensions, discoveries and improved recovery, less related costs	3,100	8,700	9,700
Net changes in prices and production cost (f)	27,600	7,300	51,600
Revisions of previous reserve estimates	(10,700)	(3,000)	2,500
Net change in taxation	1,900	6,100	(16,700)
Future development costs	(3,200)	(1,600)	(5,100)
Net change in purchase and sales of reserves-in-place	(1,000)	(5,300)	800
Addition of 10% annual discount	8,100	7,700	4,400
Total change in the standardized measure during the year	8,000	4,000	32,000

(a)

The year-end marker prices used were Brent $40.24/bbl, Henry Hub $6.01/mmbtu (2003 Brent $30.10/bbl, Henry Hub $5.76/mmbtu; 2002 Brent $30.38/bbl, Henry Hub $4.13/mmbtu).

(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 statutory corporate 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)

Minority interest in BP Trinidad and Tobago LLC amounted to $1,600 million at December 31, 2004 ($1,700 million at December 31, 2003 and $700 million at December 31, 2002).

(f)

Net changes in prices and production costs includes the effect of exchange movements.

Equity-accounted entities

In addition, at December 31, 2004 the Group's share of the standardized measure of discounted future net cash flows of equity-accounted entities amounted to $11,200 million ($12,000 million at December 31, 2003 and $4,300 million at December 31, 2002).

Operational and statistical information

The following tables present operational and statistical information related to production, drilling, productive wells and acreage.

Crude oil and natural gas production

The following table shows crude oil and natural gas production for the years ended December 31, 2004, 2003 and 2002.

Production for the year (a)

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Others	Total
				(thousand barrels per day)					
Subsidiary undertakings									
Crude oil (b)									
2004	330	77	666	173	48	130		56	1,480
2003	377	84	726	194	59	117		58	1,615
2002	461	104	765	180	73	124		59	1,766
				(million cubic feet per day)					
Natural gas (c)									
2004	1,174	125	2,749	2,334	775	267		200	7,624
2003	1,446	119	3,128	2,168	775	253		203	8,092
2002	1,550	147	3,483	1,799	855	256		234	8,324
Equity-accounted entities									
(BP share)									
Crude oil (b)									
2004				68	2		831	150	1,051
2003				63	2		296	145	506
2002	1			57	2		73	119	252
Natural gas (c)									
2004				353	60		458	8	879
2003				312	73		129	7	521
2002	5			283	77		6	12	383

(a) All volumes are net of royalty, whether payable in cash or in kind.

(b) Crude oil includes natural gas liquids and condensate.

(c) Natural gas production excludes gas consumed in operations.

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, 2004. 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.

		UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Others	Total
Number of productive wells at December 31, 2004										
Oil wells (a)	gross	381	79	8,493	3,291	329	611	21,895	1,395	36,474
	net	148.1	25.4	2,608.8	1,834.0	142.9	563.4	9,603.7	235.9	15,162.2
Gas wells (b)	gross	319	43	16,974	2,151	516	71	48	118	20,240
	net	148.8	15.3	11,003.6	1,334.4	188.9	33.9	23.5	49.4	12,797.8

(a) Includes approximately 1,036 gross (308.9 net) multiple completion wells (more than one formation producing into the same well bore).

(b) Includes approximately 1,891 gross (999.4 net) multiple completion wells. If one of the multiple completions in a well is an oil completion, the well is classified as an oil well.

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Others	Total
					(thousands of acres)				
Oil and natural gas acreage at December 31, 2004									
Developed									
gross	507	138	7,211	2,410	671	231	4,151	1,590	16,909
net	221.9	46.1	4,844.2	1,271.8	208.0	131.0	1,820.8	156.6	8,700.4
Undeveloped (a)									
gross	2,484	2,972	7,524	23,506	9,615	10,203	13,810	14,822	84,936
net	1,328.5	1,120.3	5,387.7	12,803.6	3,794.2	5,318.2	5,714.9	3,305.4	38,772.8

(a) Undeveloped acreage includes leases and concessions.

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 Americas	Asia Pacific	Africa	Russia	Others	Total
2004									
Exploratory									
productive			2.1	1.3		6.6	11.0	1.3	22.3
dry			3.2	1.5		2.0	5.2	1.1	13.0
Development									
productive	10.0	0.3	513.3	138.2	8.6	12.9	166.8	16.0	866.1
dry	0.1		3.0	1.8		2.0	8.7	2.4	18.0
2003									
Exploratory									
productive	0.3	1.1	1.0	2.8		5.2	1.8	0.7	12.9
dry		0.2	0.8	1.3	0.5	1.5	0.3	1.2	5.8
Development									
productive	11.0	2.8	466.2	139.5	8.8	26.1	39.3	12.1	705.8
dry	0.4	0.3	5.5	3.8	1.1	1.0	1.7	0.7	14.5
2002									
Exploratory									
productive	0.8	0.4	2.1	6.8	4.3	5.0	0.8	0.4	20.6
dry		0.5	1.0	16.5	0.3	2.3	0.5		21.1
Development									
productive	17.3	1.5	384.2	139.9	22.7	24.5	14.0	11.8	615.9
dry	2.8		19.7	25.5		1.0		1.8	50.8

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, 2004. Suspended development wells and long-term suspended exploratory wells are also included in the table.

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Others	Total
At December 31, 2004									
Exploratory									
gross			30	5	5	3	3	1	47
net			14.0	3.3	2.6	2.4	1.2	0.3	23.8
Development									
gross	11	1	162	22	2	22	20	27	267
net	3.4	0.3	100.2	18.2	0.8	6.4	8.7	6.8	144.8

Exploration wells

During 2004 BP continued activity on suspended wells, and following technical, commercial and management review, has determined that it is appropriate to continue to carry the suspended well costs as assets as sufficient progress is being made towards the final assessment of the economic viability of these discoveries.

The table below provides information about the exploration wells whose costs have been carried for more than one year after the completion of drilling and are classified as intangible assets at December 31, 2004:

Country/Project	Amounts carried as intangible assets at year end 2004	Number of wells gross	Years wells drilled	Anticipated year of proved reserve booking	Comment
	($ millions)				
Angola	**99**	**19**			
Clochas/Tchihumba	14	2	2003	2009	Initial assessment of hydrocarbon quantities as potentially commercial completed; potential requirement for further appraisal identified; negotiations in progress with joint venture partners; development options identified and under evaluation; development awaiting capacity in existing infrastructure.
Bavuca/Kakocha Mbulumbumba	15	3	2000-2003	2011	Assessment of hydrocarbon quantities as potentially commercial completed; negotiations in progress with joint venture partners; development options identified and under evaluation; development planned in two phases through tieback to existing infrastructure.

Lirio/Cravo	7	2	1998-1999	2009	Initial assessment of hydrocarbon quantities as potentially commercial completed; potential requirement for further appraisal identified; Declaration of Commercial Discovery submitted; development options identified and under evaluation; planned subsea tieback to floating production system.
Mondo/Saxi/Batuque	31	7	2000-2003	2005-2008	Assessment of hydrocarbon quantities as potentially commercial completed; Declaration of Commercial Discovery submitted; development option selected; planned subsea tieback to floating production system.
Orquidea, Violeta, Tulipa	9	3	1999-2001	2007-2011	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic and developmental aspects of project in progress; planned subsea tieback to floating production system; high-resolution 3-D seismic survey in 2004; submission of Declaration of Commercial Discovery anticipated in 2005.

Cesio/Chumbo	23	2	2003	2008	Initial assessment of hydrocarbon quantities as potentially commercial completed; potential requirement for further appraisal identified; assessment of developmental aspects in progress; development planned with tieback to standalone floating production system as part of area development in 2008; alternative development plan for tieback via existing facilities.
Australia	**24**	**6**			
WA267-P	24	6	1999-2001	2006	Initial assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation.
Colombia	**133**	**4**			
Floreña/Pauto	90	3	1997-1998	2005-2009	Initial assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project in progress; development options identified and under evaluation; phased development scheme, production from earlier phases in 2002-2004; subsequent phase via expansion of existing infrastructure.

Volcanera	43	1	1993	2009	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project in progress; development options identified and under evaluation; planned phased development linked to neighbouring field using existing infrastructure.
Egypt	**36**	**12**			
Baltim Tersa	7	2	1995-1999	2005-2007	Assessment of hydrocarbon quantities as potentially commercial completed; development option selected; planned tieback to existing infrastructure; part of existing producing concession with gas sale agreement.
East Delta Deep Marine Thalab	7	2	2000-2002	2007	Initial assessment of hydrocarbon quantities as potentially commercial completed; potential requirement for further appraisal identified; assessment of economic aspects of project in progress; planned subsea tieback to existing infrastructure.
Saqqara	7	1	2003	2004	Final investment decision made; costs to be transferred to development costs in 2005.

Temsah	15	7	1995-1997	2005-2010	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; planned subsea tieback to existing infrastructure; gas sale agreement in place.
Norway	**77**	**9**			
Ellida	12	1	2003	Not applicable	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project completed. BP disposed of its interest in January 2005.
Skarv/Snadd	65	8	1998-2002	2006-2007	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; assessment of export infrastructure alternatives and negotiations with partners on development plan are in progress.
Trinidad	**113**	**6**			
Cashima	17	1	2001	2009	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; development awaiting capacity in existing infrastructure.

Corallita/Lantana	24	2	1996	2008	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; planned subsea tieback to existing infrastructure; fields dedicated to LNG gas contract delivery.
Manakin	18	1	2000	2010-2011	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project in progress; development options identified and under evaluation; planned subsea tieback to existing LNG train; government discussions on unitization underway.
Red Mango	54	2	2000-2002	2007	Assessment of hydrocarbon quantities as potentially commercial completed; development option selected; planned subsea tieback to existing infrastructure.
United Kingdom	**195**	**19**			
Andrew	14	1	1998	2007	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; development awaiting capacity in existing infrastructure.

Devenick	97	3	1983-2001	2005-2006	Initial assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic and developmental aspects of project in progress; integrated field model, subsurface and seismic studies under review.
Kessog	35	4	1986-1987	2007	Initial assessment of hydrocarbon quantities as potentially commercial completed; potential requirement for further appraisal identified; active negotiation of agreements with venture partners.
Puffin	29	9	1982-1991	2007-2008	Assessment of hydrocarbon quantities as potentially commercial completed; further assessment of economic and developmental aspects of project to be undertaken; development awaiting capacity in existing infrastructure.
Suilven	20	2	1996-1998	2010	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic and developmental aspects of project in progress; development awaiting capacity in existing infrastructure.

United States	**216**	**12**			
Blind Faith	57	2	2001	Not applicable	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic and developmental aspects of project in progress. BP disposed of its interest in February 2005.
Deimos	13	1	2002-2003	2005	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; development in two phases; first phase sanctioned in 2004; second phase planned with subsea tieback.
Dorado	61	3	2002	2005	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; planned subsea tieback to existing infrastructure.
Entrada	33	2	2000	2005-2006	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation; expected development as subsea tieback to existing/planned facilities.

Langley-Canada	5	1	2003	2009-2010	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic and developmental aspects of project completed; development dependent on construction of major pipeline expected to be operational by 2010.
Liberty	20	1	1997	2008	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation. Planned tieback to existing infrastructure; Memorandums Of Understanding with key permitting agencies are being secured.
Point Thomson/Sourdough	27	2	1994-1996	2008	Assessment of hydrocarbon quantities as potentially commercial completed; development options identified and under evaluation. Annual Plan of Development work programme approved by state; initial engineering design for gas cycling option complete; also progressing alternative development options including tie in to proposed Alaska gas pipeline.

Country/Project	Amounts carried as intangible assets at year end 2004	Number of wells gross	Years wells drilled	Anticipated year of proved reserve booking	Comment
	($ millions)				
Vietnam	**78**	**4**			
Hai Thach	65	3	1995-2002	2007	Assessment of hydrocarbon quantities as potentially commercial completed; assessment of economic aspects of project completed; development options identified and under evaluation.
Kim Cuong Tay	13	1	1995	2010-2019	Initial assessment of hydrocarbon quantities as potentially commercial completed; requirement for further appraisal identified.
Miscellaneous small projects	**19**	**12**	1993-2002	2005-2019	
TOTAL	**990**	**103**			

SCHEDULE II

BP p.l.c. AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS

	Balance at January 1,	Additions: Charged to costs and expenses	Additions: Charged to other accounts (a)	Deductions	Balance December 31,
			($ million)		
2004					
Fixed assets Investments (b)	211	12	4	(57)	170
Doubtful debts (b)	441	254	6	(175)	526
2003					
Fixed assets Investments (b)	678		4	(471)	211
Doubtful debts (b)	445	139	29	(172)	441
2002					
Fixed assets Investments (b)	632	13	37	(4)	678
Doubtful debts (b)	290	179	49	(73)	445

(a) Principally currency transactions.

(b) Deducted in the balance sheet from the assets to which they apply.

BP p.l.c. AND SUBSIDIARIES

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 Amendment No. 1 to this annual report on its behalf.

BP p.l.c.
(Registrant)

/s/ D. J. PEARL

D. J. Pearl
Deputy Company Secretary

Dated: June 13, 2006

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