BP PLC
Form 20-F
June 28, 2004

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 20-F

(Mark One)

[ ]	REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) or (g) OF THE SECURITIES EXCHANGE ACT OF 1934 OR
[ü]	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)** **OF THE SECURITIES EXCHANGE ACT OF 1934** **For the fiscal year ended December 31, 2003** OR
[ ]	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to
Commission file number 1-6262

BP p.l.c.

(Exact name of Registrant as specified in its charter)

ENGLAND and WALES

(Jurisdiction of incorporation or organization)

1 St James s Square

London

SW1Y 4PD

England

(Address of principal executive offices)

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

Title of each class	Name of each exchange on which registered
Ordinary Shares of 25c each	**Chicago Stock Exchange***

New York Stock Exchange*

Pacific Exchange, Inc.*

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

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

None

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

None

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

Ordinary Shares of 25c each	**22,122,610,104**
Cumulative First Preference Shares of £1 each	**7,232,838**
Cumulative Second Preference Shares of £1 each	**5,473,414**

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ü No

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

Item 17 Item 18 ü

TABLE OF CONTENTS

TABLE OF CONTENTS

Table of Contents

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 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 program 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.

4

Table of Contents

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.

Joint venture 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.

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.

Table of Contents

Pence or p One hundredth of a pound.

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.

Table of Contents

PART I

ITEM 1 IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISORS

Not applicable.

ITEM 2 OFFER STATISTICS AND EXPECTED TIMETABLE

Not applicable.

ITEM 3 KEY INFORMATION

SELECTED FINANCIAL INFORMATION

Summary

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

	Years ended December 31,				
	2003	2002	2001	2000	1999
	($ million except per share amounts)				
UK GAAP					
Income statement data					
Turnover	236,045	180,186	175,389	161,826	101,180
Less: joint ventures	3,474	1,465	1,171	13,764	17,614
Group turnover	232,571	178,721	174,218	148,062	83,566
Profit for the year	10,267	6,845	6,556	10,120	4,566
Per ordinary share: (cents)					
Profit for the year:					
Basic	46.30	30.55	29.21	46.77	23.55

Diluted	45.87	30.41	29.04	46.46	23.42
Dividends per share (cents)	26.00	24.00	22.00	20.50	20.00
Dividends per share (pence)	15.517	15.638	15.436	13.791	12.339
Ordinary share data (a)					
Average number outstanding of 25 cents ordinary shares (shares million undiluted)	22,171	22,397	22,436	21,638	19,386
Average number outstanding of 25 cents ordinary shares (shares million diluted)	22,429	22,504	22,574	21,783	19,497
Balance sheet data					
Total assets	177,572	159,125	141,970	144,862	89,481
Net assets	77,063	70,047	65,759	66,152	38,092
Share capital	5,552	5,616	5,629	5,653	4,892
BP shareholders interest	75,938	69,409	65,161	65,584	37,031
Finance debt due after more than one year	12,869	11,922	12,327	14,772	9,644
Debt to borrowed and invested capital (b)	14%	15%	16%	18%	20%

Table of Contents

	Years ended December 31,				
	2003	2002	2001	2000	1999
	($ million except per share amounts)				
US GAAP					
Income statement data					
Revenues	232,571	178,721	174,218	148,062	83,566
Profit for the year	13,143	8,397	4,164	10,183	4,596
Comprehensive income	20,088	10,544	2,649	7,730	3,674
Profit per ordinary share: (cents)					
Basic	59.27	37.48	18.55	47.05	23.70
Diluted	58.70	37.30	18.44	46.74	23.56
Profit per American Depositary Share: (cents)					
Basic	355.62	224.88	111.30	282.30	142.20
Diluted	352.20	223.80	110.64	280.44	141.36
Balance sheet data					
Total assets	186,359	164,103	145,990	151,966	90,262
Net assets	80,889	67,759	62,920	66,122	38,899
BP shareholders interest	79,764	67,121	62,322	65,554	37,838

(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.

8

Table of Contents

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, together with the refund but before deduction of withholding taxes as described in Item 10 Additional Information Taxation on page 166. 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.

		Quarterly				
Dividends per American Depositary Share (a)		First	Second	Third	Fourth	Total
1999	UK pence	20.5	20.8	20.2	20.8	82.3
	US cents	33.3	33.3	33.3	33.4	133.3
	Can. cents	48.7	50.1	48.6	48.5	195.9
2000	UK pence	21.5	22.3	24.0	24.1	91.9
	US cents	33.3	33.3	35.0	35.0	136.6
	Can. cents	49.7	49.8	53.6	53.2	206.3
2001	UK pence	24.4	26.1	25.4	27.0	102.9
	US cents	35.0	36.7	36.7	38.3	146.7
	Can. cents	53.7	56.0	58.5	61.0	229.2
2002	UK pence	27.0	25.8	26.0	25.4	104.2
	US cents	38.3	40.0	40.0	41.7	160.0
	Can. cents	60.1	63.0	62.3	63.8	249.2
2003	UK pence	26.3	26.9	25.7	24.5	103.4
	US cents	41.7	43.3	43.3	45.0	173.3
	Can. cents	60.3	60.0	56.8	59.7	236.8

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

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

A dividend reinvestment plan is, however, available for holders of ADSs through JPMorgan Chase Bank.

Future dividends will be dependent upon future earnings, the financial condition of the Group, the Risk Factors set out below, and other matters which may affect the business of the Group set out in Item 5 Operating and Financial Review and Prospects on page 78.

Table of Contents

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

Table of Contents

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.

Table of Contents

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 , plan similar expressions. In particular, among other statements, (i) certain statements in Item 4 Information on the Company and Item 5 Operating and Financial Review and Prospects with regard to management aims and objectives, 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 and Prospects, including under Liquidity and Capital Resources with regard to future cash flows, future levels of capital expenditure and divestments, working capital, 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, petrochemical margins and sales; and under Prospects with regard to the plans and prospects of the Group, forward-looking rules of thumb, changes to BP s financial reporting due to the adoption of FRS 17, operating capital employed/capital in service, cash returns, underlying cash flows, finding and development costs, BP s intentions with respect to shareholder distributions and share buybacks, gearing, opportunities for material acquisitions and costs for providing pension and other postretirement benefits 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; successful 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.

SPECIAL NOTICE

The Company has received comments from the Staff of the SEC relating to our Annual Report on Form 20-F for the year ended December 31, 2002, and as of the date of filing this 2003 Form 20-F, the SEC review process is still ongoing.

Table of Contents

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

Our operating business segments are Exploration and Production; Gas, Power and Renewables; Refining and Marketing; and Petrochemicals. Exploration and Production s activities include oil and natural gas exploration and field development and production (upstream activities), together with pipeline transportation and natural gas processing (midstream activities). Gas, Power and Renewables activities include marketing and trading of natural gas, NGL, new market development and LNG, and solar and renewables. 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 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.

Table of Contents

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 just under 30% located in the UK and the Rest of Europe.

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

In Exploration and Production we have upstream interests in 25 countries. In addition to our drive to maximize the value of our existing portfolio we are creating 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 the Deepwater Gulf of Mexico, Trinidad, Angola, Algeria, Azerbaijan, Russia and Asia Pacific, 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 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.

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 the world s third largest petrochemical company, based on production capacity, 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 PTA, PX and acetic acid, and Olefins and Derivatives (O&D) comprising ethylene and related co-products, polypropylene, HDPE and acrylonitrile. On April 27, 2004 we announced our intention to set up a separate corporate entity for the O&D businesses. It is our intention to make a public offering of this new entity at an appropriate time. Based on the estimated lead time required for such a transaction, and depending on market circumstances, we are aiming to make such an offering in the second half of 2005. We intend to retain and grow the A&A businesses, which will be transferred to the Refining and Marketing segment on January 1, 2005.

Acquisitions and Disposals

There were no significant acquisitions in 2001. Disposals in 2001 comprised a number of small transactions, with total proceeds of $2,903 million.

Table of Contents

With effect from February 1, 2002, BP acquired a majority stake in Veba from E.ON. Veba owns Aral, Germany s biggest fuels retailer. BP paid E.ON $1.6 billion in cash and assumed some $1.0 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. BP s net investment in TNK-BP following this transaction was $6.7 billion.

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. TNK-BP and Sibneft will continue to work together to finalize an agreement to split the main assets of Slavneft between the two companies.

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 January 13, 2004, BP sold its 2% stake in PetroChina Company Limited (PetroChina) for $1.65 billion. On February 10, 2004 we sold our 2.1% stake in Sinopec for $0.7 billion.

Table of Contents

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.

	Years ended December 31,				
	2003	2002	2001	2000	1999
			($ million)		
Turnover	236,045	180,186	175,389	161,826	101,180
Less: joint ventures	3,474	1,465	1,171	13,764	17,614
Group turnover (sales to third parties)	232,571	178,721	174,218	148,062	83,566
Total operating profit (a)	16,429	11,375	14,127	18,407	10,622
Profit for the year*	10,267	6,845	6,556	10,120	4,566
Capital expenditure and acquisitions	20,075 (b)	19,111 (b)	14,124	47,613 (b)	7,345 (c)
Total assets	177,572	159,125	141,970	144,862	89,481

* 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 and taxation.

(b) Capital expenditure and acquisitions 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, for 2000 includes $27,506 million for the acquisition of Atlantic Richfield and $8,936 million for other significant one-off cash investments.

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

With the exception of the Atlantic Richfield acquisition, which was a share transaction, 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 2003, 2002 and 2001 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 47 on page F-87.

Table of Contents

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

	Years ended December 31,				
	2003	2002	2001	2000	1999
Total crude oil production (thousand barrels per day) (a)	2,121	2,018	1,931	1,928	2,061
Total natural gas production (million cubic feet per day) (a)	8,613	8,707	8,632	7,609	6,067
Estimated net proved crude oil reserves (million barrels) (b)	7,214	7,762	7,217	6,508	6,535
Estimated net proved natural gas reserves (billion cubic feet) (b)	45,155	45,844	42,959	41,100	33,802
Total estimated net proved crude oil reserves (million barrels) (c)	10,081	9,165	8,376	7,643	7,572
Total estimated net proved natural gas reserves (billion cubic feet) (d)	48,024	48,789	46,175	43,918	35,526

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

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

(c) Including reserves of equity-accounted entities. Includes 152 million barrels (17 million barrels at December 31, 2002 and 20 million barrels at December 31, 2001) in respect of the 30% minority interest in BP Trinidad and Tobago LLC and the 5.4% minority interest held in subsidiaries of TNK-BP.

(d) Including reserves of equity-accounted entities. Includes 4,505 billion cubic feet of natural gas (1,185 billion cubic feet at December 31, 2002 and 1,258 billion cubic feet at December 31, 2001) in respect of the 30% minority interest in Trinidad and Tobago LLC and the 5.4% minority interest held in subsidiaries of TNK-BP.

During 2003, 1,289 million barrels of oil and natural gas, on an oil equivalent* basis (mmboe), were added to BP s proved reserves (excluding purchases, sales and equity-accounted entities), more than replacing the volume produced. After allowing for production, which amounted to 1,085 mmboe, BP s proved reserves, excluding equity-accounted entities, increased to 14,999 mmboe. These proved reserves are mainly located in the USA (40%), Rest of Americas (23%) and the UK (11%).

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

[Table of Contents](#)

SEGMENTAL INFORMATION

The following tables show turnover and profit before interest and tax by business and by geographical area for the years ended December 31, 2003, 2002 and 2001.

	Years ended December 31,								
	2003			2002			2001		
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	31,341	23,279	8,062	25,753	18,556	7,197	28,229	19,660	8,569
Gas, Power and Renewables	65,445	1,963	63,482	37,357	1,320	36,037	39,442	2,954	36,488
Refining and Marketing	149,477	4,448	145,029	125,836	3,366	122,470	120,233	2,903	117,330
Petrochemicals	16,075	592	15,483	13,064	557	12,507	11,515	233	11,282
Other businesses and corporate	515		515	510		510	549		549
Group turnover	262,853	30,282	232,571	202,520	23,799	178,721	199,968	25,750	174,218
Share of joint venture sales			3,474			1,465			1,171
			236,045			180,186			175,389

	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)	54,971	15,275	39,696	48,748	14,673	34,075	47,618	13,467	34,151
Rest of Europe	50,582	8,672	41,910	46,518	7,980	38,538	36,701	7,603	29,098
USA	108,910	2,169	106,741	80,381	2,099	78,282	84,696	939	83,757
Rest of World	52,498	8,274	44,224	34,401	6,575	27,826	33,911	6,699	27,212
	266,961	34,390	232,571	210,048	31,327	178,721	202,926	28,708	174,218
Share of joint venture sales									
UK			144			129			13
Rest of Europe			290			298			30

USA	177	236	318
Rest of World	2,863	802	810
	3,474	1,465	1,171

(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.

18

Table of Contents

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, 2003						
By business						
Exploration and Production	12,754	914	272	13,940	913	14,853
Gas, Power & Renewables	481		(3)	478	(6)	472
Refining and Marketing	2,128	29	135	2,292	(213)	2,079
Petrochemicals	550	(19)	92	623	38	661
Other businesses and corporate	(922)		18	(904)	99	(805)
	14,991	924	514	16,429	831	17,260
By geographical area						
UK (c)	2,590	(19)	14	2,585	717	3,302
Rest of Europe	1,966		12	1,978	(151)	1,827
USA	5,485	27	79	5,591	(347)	5,244
Rest of World	4,950	916	409	6,275	612	6,887
	14,991	924	514	16,429	831	17,260
Year ended December 31, 2002						
By business						
Exploration and Production	8,598	343	268	9,209	(726)	8,483
Gas, Power & Renewables	298		107	405	1,551	1,956
Refining and Marketing	1,717	24	180	1,921	613	2,534
Petrochemicals	551	(20)	10	541	(256)	285
Other businesses and corporate	(753)		52	(701)	(14)	(715)
	10,411	347	617	11,375	1,168	12,543
By geographical area						
UK (c)	1,788	(14)	10	1,784	(88)	1,696
Rest of Europe	1,856	(2)	132	1,986	1,817	3,803
USA	3,305	17	136	3,458	(242)	3,216
Rest of World	3,462	346	339	4,147	(319)	3,828
	10,411	347	617	11,375	1,168	12,543
Year ended December 31, 2001						
By business						
Exploration and Production	11,796	373	186	12,355	195	12,550
Gas, Power & Renewables	223		184	407		407
Refining and Marketing	1,712	83	195	1,990	471	2,461
Petrochemicals	(201)	(17)	116	(102)	(297)	(399)
Other businesses and corporate	(598)		75	(523)	166	(357)
	12,932	439	756	14,127	535	14,662

By geographical area						
UK (c)	2,435	(5)	13	2,443	(319)	2,124
Rest of Europe	1,138	(4)	236	1,370	33	1,403
USA	5,619	77	186	5,882	289	6,171
Rest of World	3,740	371	321	4,432	532	4,964
	12,932	439	756	14,127	535	14,662

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

(b) Exceptional items comprise profit or loss on the sale of fixed assets and businesses or termination of operations.

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

Table of Contents

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 25 countries. Areas of activity include the USA, UK, Norway, Canada, South America, Africa, the Middle East and Asia Pacific. Production during 2003 came from 23 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 three major LNG plants the Atlantic LNG plant in Trinidad (BP 34% in Train 1, 42% in Trains 2 and 3, and 38% in Train 4), in Indonesia through our interests in the Sanga-Sanga Production Sharing Agreement (PSA, BP 38%), which supplies natural gas to the Bontang LNG plant 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 have 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. This will have no impact on the Exploration and Production segment s reported production. Our 2003 results have not been restated to reflect this transfer. The impact that this would have had on our 2003 segment results is shown under Transfer of Natural Gas Liquids Activities on page 112 in Item 5 Operating and Financial Review and Prospects Group Operating Results.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Turnover (a)	31,341	25,753	28,229
Total operating profit	13,940	9,209	12,355
Total assets	79,344	72,801	70,017
Capital expenditure and acquisitions	15,452	9,699	8,861
		($ per barrel)	
Average BP crude oil realizations (b)	28.23	24.06	23.27
Average BP NGL realizations (b)	19.26	12.85	16.27
Average BP liquids realizations (b) (c)	27.25	22.69	22.50
Average West Texas Intermediate oil price	31.06	26.14	25.89
Average Brent oil price	28.83	25.03	24.44
		($ per thousand cubic feet)	
Average BP natural gas realizations (b)	3.39	2.46	3.30
Average BP US natural gas realizations (b)	4.47	2.63	3.99
		($ per mmbtu)	
Average Henry Hub gas price (d)	5.37	3.22	4.26

(a) Excludes BP s share of joint venture turnover of $2,587 million in 2003, $539 million in 2002 and $666 million in 2001.

(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, 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, Algeria, Angola, Trinidad, Deepwater Gulf of Mexico and Russia.

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 only the best projects for development;
- manage the performance of producing assets by investing only 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 are currently developing 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, 2003 capital expenditure and acquisitions was $15.5 billion, including $5.8 billion for the purchase of our interest in TNK-BP. 2002 capital expenditure and acquisitions at $9.7 billion was 9% higher than the 2001 level of $8.9 billion. Excluding acquisitions, capital expenditure in 2003 was $9.7 billion compared with $9.3 billion in 2002 and $8.6 billion in 2001. Development expenditure incurred in 2003, excluding midstream activities, was $7,547 million compared with $7,235 million in 2002 and $6,858 million in 2001. 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 2004 is planned to be approximately $9 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 2003 were $826 million compared to $1,108 million in 2002. About 34% of 2003 exploration and appraisal capital was directed towards appraisal activity as we delineated the discoveries made during 2000, 2001, and 2002. In 2003, we participated in 74 gross (32 net) exploration and appraisal wells in 19 countries. The principal areas of activity were Angola, Egypt and the USA.

Total exploration expense in 2003 of $542 million (2002, $644 million) includes the write-off of unsuccessful drilling activity in Colombia (Niscota - $62 million) and in Brazil (Reki - $30 million).

In 2003, we obtained upstream rights in several new tracts, which include the following:

In Egypt, BP were awarded six new blocks in the Gulf of Suez and northern Red Sea.

In the Gulf of Mexico, BP was successful in the Outer Continental Shelf Lease Sales 185 and 187 with bids on 80 blocks, of which 58 were won, for an overall success rate of 73%. BP also gained leases in Louisiana state waters where we were 100% successful in purchasing the blocks we bid on.

Table of Contents

In 2003, we were involved in discoveries in Angola, Azerbaijan, Egypt 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 2003 discoveries included the following:

In Angola, BP made further discoveries in the ultra deep water (greater than 1,500 metres) acreage with the Saturno and Marte wells in Block 31 (BP 26.7% and operator), and in Block 18 (BP 50% and operator) with the Cesio and Chumbo discoveries. Continued success was experienced in the established partner-operated deepwater blocks; in Block 15 (BP 26.7%) the Clochas, Kakocha and Tchihumba discoveries, and in Block 17 (BP 16.7%) the Hortensia and Acacia discoveries.

In Egypt, BP successfully appraised the 2002 Ruby discovery with the Ruby-2 well in the West Mediterranean Deep Water Concession (BP 80%) in the Nile Delta. In the Gulf of Suez, BP drilled the discovery well Saqqara-1 in the LL87 block. This was the largest oil discovery in the Gulf of Suez in nearly 14 years.

In the Deepwater Gulf of Mexico, a discovery was made with the Tubular Bells well (BP 50% and operator) in the Mississippi Canyon.

In Azerbaijan a deeper reservoir was discovered in the Shah Deniz field.

2004 activity has resulted in further discoveries with the Bavuca well in Angola Block 15 (BP 26.7%) and in Egypt with the Raven 1 well in the North Alexandria Concession (BP 60% and operator) and the Taurt well in the Ras El Barr concession (BP 50% and operator).

Reserves and Production

BP manages its hydrocarbon resources in three major categories: prospect inventory; non-proved reserves and proved reserves. When a discovery is made, volumes transfer from the prospect inventory to the non-proved reserve category. The reserves move through various non-proved reserves sub-categories as their technical and commercial maturity increase 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.

BP has an internal process to control the quality of reserve bookings which forms part of an holistic and 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 key element is the accountabilities of certain officers of the Company which ensure that there is clear responsibility for review and, where appropriate, endorsement of changes to reserves bookings; that the review is independent of the operating business unit for the integrity and accuracy of the reserve estimates; and that there are effective controls in the reserve approval process and verification that the Group s reserve estimates and the related financial impacts are reported in a timely manner.

Table of Contents

The second key 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 review that both technical and commercial criteria are met prior to the commitment of capital to projects.

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

The fifth and final key element is that we have established criteria whereby reserves 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 70% of the BP reserves base undergoes central review every two years and more than 80% 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 2004, BP s variable pay program for the senior managers in the Exploration and Production business segment will be based on Annual Bonus Contracts. Annual Bonus 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, 2003, 2002 and 2001 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 disclose our share of reserves held in joint ventures and associated companies although we do not control these entities or the assets held by such entities.

Of the Group s oil and gas reserves held in consolidated companies, approximately 94% have been estimated by the Group s petroleum engineers and approximately 6% have been estimated by others such as the field operator or independent engineering consultants. Of the oil and gas reserves held in equity-accounted companies, approximately 24% 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

Table of Contents

entitlement is driven by the monetary amount of costs to be recovered, price fluctuations will have an impact on both production volumes and reserves. 14% 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.

In our UK GAAP financial reporting, the Group uses its long-term planning prices in determining estimates of its proved reserves, which is an accepted practice 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). Planning prices 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 2003 were $16/bbl for oil and $2.70/mscf for natural gas. From 2004 we increased our planning prices to $20/bbl for oil and $3.50/mscf for natural gas. Applying higher year-end prices to reserve estimates has the effect of increasing proved reserves associated with concessions (tax and royalty arrangements) for which additional development opportunities become economical at higher prices or where higher prices make it more economical 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. On an aggregate basis, the impact on our proved reserves of using higher year-end prices instead of our planning prices is broadly in balance, although there are relatively larger variations on a regional basis. 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 has received comments from the Staff of the SEC relating to the Annual Report on Form 20-F for the year ended December 31, 2002 and as of the date of filing this Form 20-F this review process is still ongoing. The Company s proved reserves estimates for the year ended December 31, 2003 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. On an aggregate basis, the net impact of these changes, comprising some reductions and some additions, is an increase of 23 mmboe included in our total proved reserves of 18,361 mmboe (including equity-accounted entities) compared to our reserves under UK SORP. Reserve estimates for prior years have not been adjusted (The 2003 year-end marker prices used were Brent $30.10/bbl and Henry Hub $5.76/mmbtu). These changes, together with the other 2003 movements in proved reserves, are reflected in the tables showing movements in oil and gas reserves by region in the Supplementary Oil and Gas Information on pages S-1 and S-5. These changes had no material impact on our profit for the year as adjusted to accord with US GAAP.

Total hydrocarbon proved reserves, on an oil equivalent basis and excluding equity-accounted entities, comprised 14,999 mmboe at December 31, 2003, a decrease of 4.3% compared with December 31, 2002. Natural gas represents about 50% of these reserves. This reduction includes net sales of 871 mmboe. The proved reserve replacement ratio, at 119% (2002 175%, 2001 191%), exceeded production for the eleventh consecutive year. 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. 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. The proved reserve replacement ratio including sales and purchases of reserves-in-place but excluding equity-accounted entities was 39% (2002 190%, 2001 191%) and including both sales and purchases of reserves-in-place and equity-accounted entities was 160% (2002 198%, 2001 191%).

In 2003, total additions to the Group s proved reserves (excluding sales and purchases of reserves-in-place and equity-accounted entities) amounted to 1,289 mmboe, mostly through extensions to existing fields and discoveries of new fields. Of these reserve additions, approximately 65% 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 (Greater Plutonio and Dalia), Norway (Ormen Lange), UKCS (Rhum), Azerbaijan (Shah Deniz), Gulf of Mexico (Atlantis) and Australia (Northwest Shelf LNG) and it is planned to bring these into production over the period 2004 - 2008.

Total hydrocarbon proved reserves, on an oil equivalent basis and including equity-accounted entities, comprised 18,361 mmboe at December 31, 2003, an increase of 4.5% compared with December 31, 2002. Natural gas represents about 45% of these reserves. This increase includes purchases of 1,657 mmboe, of which 1,600 mmboe represents the incremental addition as a result of the purchase of 50% of TNK-BP and sales of 1,016 mmboe following completion of the divestment of assets in the North Sea primarily Forties and the Bacton Area in the UK and Gyda in Norway, along with a package of assets in the Gulf of Mexico shelf and the dilution of our gas assets, In Amenas and In Salah, in Algeria.

Additions to proved developed reserves in 2003 were 1,370 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 and equity-accounted entities) was 105% (2002 118%, 2001 95%).

In our existing profit centres our decline rates are averaging in the 3% to 4% range over the period 2002-2004. Beyond 2004, we estimate the decline will be approximately 3% per annum from 2004-2008. The decline rate is mitigated by the development of new projects and the investment in incremental reserves in and around existing fields. Cash returns will reduce slightly as we manage the decline. In our new profit centres, we anticipate strong volume growth and increasing cash returns. For a definition and discussion of cash returns, see Item 5 Operating and Financial Review and Prospects Prospects on page 101.

Our total hydrocarbon production (including equity-accounted entities) during 2003 averaged 3,606 thousand barrels of oil equivalent per day (mboe/d), an increase of 87 mboe/d, or 2.5% compared with 2002; this includes the 135 mboe/d impact of divestments offset by the inclusion of 205 mboe/d TNK-BP incremental volumes from August 29, 2003. 35% of our production was in the USA, 17% in the UK and 17% from equity-accounted entities, of which 53% is from TNK-BP and the former Sidanco. Total production for 2004 is estimated at an average of over 4 million barrels of oil equivalent per day (mmboe/d).

Table of Contents

The following tables show BP s aggregate estimated net proved reserves as at December 31, 2003.

Estimated net proved reserves of liquids at December 31, 2003 (a) (b)

	Developed	Undeveloped	Total
		(millions of barrels)	
UK	697	245	942
Rest of Europe	236	127	363
USA	1,902	1,499	3,401
Rest of Americas	385	354	739
Asia Pacific	82	81	163
Africa	190	632	822
Russia			
Other	73	711	784
	3,565	3,649	7,214
Equity-accounted entities			2,867
Total Group and BP share of equity-accounted entities			10,081

Estimated net proved reserves of natural gas at December 31, 2003 (a) (b)

	Developed	Undeveloped	Total
		(billion cubic feet)	
UK	2,996	1,095	4,091
Rest of Europe	262	1,255	1,517
USA	11,482	3,337	14,819
Rest of Americas	4,212	11,531	15,743
Asia Pacific	1,976	3,026	5,002
Africa	640	2,188	2,828
Russia			
Other	255	900	1,155
	21,823	23,332	45,155
Equity-accounted entities			2,869
Total Group and BP share of equity-accounted entities			48,024

Total proved reserves (mmboe)	18,361

(a) Net proved reserves of crude oil and natural gas, stated as of December 31, 2003, 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.

Table of Contents

(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. Fourteen of these are now in production. Holstein, Mad Dog, Thunder Horse and Atlantis are due to begin production over the period 2004-2006.

Table of Contents

The following tables show BP s production by major field for 2003, 2002 and 2001.

Liquids

Production	Field or Area	Interest	Net production 2003	2002	2001
		(%)	(thousand barrels per day)		
Alaska	Prudhoe Bay*	26.4	105	113	123
	Kuparuk	39.2	73	74	76
	Northstar*	98.6	46	36	3
	Milne Point*	100.0	44	44	45
	Other	Various	43	42	41
Total Alaska			311	309	288
Lower 48 States onshore (a)	Total	Various	160	192	213
Gulf of Mexico (a)	Mars	28.5	43	41	42
	Horn Mountain*	66.6	42	1	
	King*	100.0	31	12	
	Pompano*	73.6	15	23	21
	Ursa	22.7	17	20	23
	Other	Various	107	167	157
Total Gulf of Mexico			255	264	243
Total USA			726	765	744
UK offshore (a)	ETAP	Various	56	61	80
	Foinaven*	Various	55	72	60
	Schiehallion/Loyal*	Various	42	43	40
	Magnus*	85.0	39	31	37
	Harding*	70.0	34	42	42
	Andrew*	62.8	17	23	25
	Forties*(b)	96.1	10	50	51
	Other	Various	95	107	114
Total UK offshore			348	429	449
UK onshore	Wytch Farm*	67.8	29	32	36
Total UK			377	461	485
Norway (a)	Draugen	18.4	25	37	40
	Valhall*	28.1	21	21	22
	Ula*	80.0	16	18	18
Other Norway and Netherlands	Various	Various	22	28	20

Total Rest of Europe	84	104	100

* BP operated.

BP operates the majority of the fields in this area.

28

Table of Contents

Production	Field or Area	Interest	Net production 2003	2002	2001
		(%)	(thousand barrels per day)		
Angola	Various	Various	35	29	1
Australia	Various	16.7	40	43	40
Azerbaijan	Azeri-Chirag-Gunashli*	34.1	38	38	35
Canada	Various	Various	13	16	18
Colombia (a)	Various	Various	53	46	48
Egypt	Various	Various	73	85	91
Trinidad	Various	100.0	74	67	48
Venezuela (a)	Various	Various	53	51	54
Other (a)	Various	Various	49	61	59
Total Rest of World			428	436	394
Total Group			1,615	1,766	1,723
Equity-accounted entities					
Abu Dhabi (c)	Various	Various	138	113	126
Argentina - Pan American Energy	Various	Various	60	53	50
Russia - TNK-BP (a)	Various	Various	228		
- Sidanco	Various	Various	68	73	20
Other	Various	Various	12	13	12
Total equity-accounted entities			506	252	208
Total Group and BP share of equity-accounted entities (d)			2,121	2,018	1,931

* BP operated.

Table of Contents

Natural gas (e)

Production	Field or Area	Interest	Net Production 2003	2002	2001
		(%)	(million cubic feet per day)		
Lower 48 States onshore (a)	San Juan Coal*	Various	578	601	615
	San Juan Conventional	Various	224	196	217
	Arkoma	Various	201	206	219
	Hugoton	Various	182	169	180
	Tuscaloosa	Various	136	138	187
	Jonah*	75.2	119	113	109
	Wamsutter*	70.5	111	108	100
	Other	Various	558	715	733
Total Lower 48 States onshore			2,109	2,246	2,360
Gulf of Mexico (a)	Marlin*	78.2	93	106	79
	King s Peak*	100.0	91	16	
	Mica	50.0	57	58	27
	Other	Various	695	1,005	1,077
Total Gulf of Mexico			936	1,185	1,183
Alaska	Various	Various	83	52	11
Total USA			3,128	3,483	3,554
UK offshore (a)	Bruce*	37.0	222	221	256
	Braes	Various	174	116	100
	Marnock*	62.0	98	135	125
	West Sole*	100.0	73	72	81
	Shearwater	27.5	70	66	19
	Armada	18.2	58	71	71
	Britannia	9.0	55	56	65
	Other	Various	696	813	996
Total UK			1,446	1,550	1,713
Netherlands	P/18-2*	48.7	30	41	47
	Other	Various	37	46	52
Norway (a)	Various	Various	52	60	48
Total Rest of Europe			119	147	147

* BP operated.

BP operates the majority of the fields in this area.

Table of Contents

Production	Field or Area	Interest	Net production 2003	2002	2001
		(%)	(million cubic feet per day)		
Rest of World					
Australia	Various	16.7	285	295	237
Canada	Kirby*	95.0	48	66	72
	Other	Various	374	448	512
China	Yacheng*	34.3	74	102	108
Egypt	Ha py	50.0	83	74	66
	Temsah	50.0	66	84	26
	Other	Various	104	98	98
Indonesia	Sanga-Sanga (direct)	26.3	165	174	164
	Pagerungan*	100.0	121	189	242
	Other*	46.0	97	94	95
Sharjah	Sajaa*	40.0	101	110	125
	Other	40.0	19	24	35
Trinidad	Amherstia*	100.0	624	492	244
	Mahogany*	100.0	503	521	529
	Immortelle*	100.0	235	154	128
	Parang*	100.0	152		
	Flamboyant*	100.0	68	40	52
	Other*	100.0	112	31	58
Other (a)	Various	Various	168	148	82
Total Rest of World			3,399	3,144	2,873
Total Group			8,092	8,324	8,287
Equity-accounted entities					
Argentina - Pan American Energy	Various	Various	281	251	236
Russia - TNK-BP (a)	Various	Various	96		
- Sidanco	Various	Various	33	6	
Other	Various	Various	111	126	109
Total equity-accounted entities			521	383	345
Total Group and BP share of equity-accounted entities			8,613	8,707	8,632

* BP operated.

(a) In 2003, BP and the Alfa Group and Access-Renova 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). In 2001, BP purchased part of the interests of Statoil in Vietnam and the interest of Inaquimicas in Cusiana/Cupiagua in Colombia.

(b) The sale of BP s interest in the Forties field was completed on April 2, 2003.

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

(d) Includes NGLs from processing plants in which an interest is held of 70 mb/d, 69 mb/d, and 78 mb/d for 2003, 2002 and 2001, respectively.

(e) Natural gas production volumes exclude gas consumed in operations within the lease boundaries of the producing field.

Table of Contents

United States

2003 liquids production at 726 thousand barrels per day (mb/d) decreased 5% from 2002, while natural gas production at 3,128 million cubic feet per day (mmcf/d) decreased 10% compared with 2002.

Crude oil production was maintained at the 2002 level, with divestments and natural reservoir declines (25 mb/d) being offset by new projects and gains in operating efficiency (24 mb/d). The decline in the Natural Gas Liquids component of liquids production (39 mb/d) was caused by divestments, lower gas throughput and processing elections not to strip NGLs from produced gas (in order to sell rich gas in a high gas price environment) thus resulting in lower commercial NGL production. Gas production was lower because of divestments, natural reservoir decline and investment choices (436 mmcf/d), partly offset by new project startups and continuing ramp-up of 2002 projects (81 mmcf/d). Operational efficiency in the USA, i.e., actual production as a percentage of production capacity, was much improved in 2003, up 3% over 2002 to 93% due to less weather-related downtime and performance improvements.

Development expenditure in the USA (excluding midstream) during 2003 was $3,486 million, compared with $3,618 million in 2002 and $3,723 million in 2001. This reflects our continued focus on only investing in the best opportunities and optimizing operating efficiency.

Our activities within the United States take place in four main areas. Significant events during 2003 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 2003, our Deepwater Gulf of Mexico crude oil production was 215 mb/d, up 5% from 2002 levels. Gas production was 561 mmcf/d, up over 10% from 2002 levels.

Growth in 2003 was driven by new field startup activity, as well as strong performance from the existing major hubs. Key events include:

- Production ramp up at the Horn Mountain (BP 66.6% and operator) and King s Peak (BP 100% and operator) fields. Both fields began production in late 2002.

- The King West subsea project (BP 100% and operator) started production in June 2003.

- Production from the Na Kika Development (BP 50% and operator) commenced in November 2003. The development consists of 5 fields and 10 subsea wells connected to a centrally-located floating host facility.

- Mardi Gras transportation system construction is on track and the first segment, the Okeanos Gas Gathering System, started up in conjunction with first production from the Na Kika field in November.

The second phase of the Princess project (BP 22.69%), a 3-well subsea development to the Ursa platform, began producing in December 2003.

Development of four major projects continued in the Gulf of Mexico during 2003 Holstein (BP 50% and operator) is on track to start up late 2004 with the final stages of construction underway. Mad Dog (BP 60.5% and operator) and Thunder Horse (BP 75% and operator) are scheduled to commence production in 2005 with Atlantis (BP 56% and operator) following in 2006. These projects will be the major contributor to the anticipated growth in production from 312 mboe/d to 550 mboe/d.

Additionally, the divestment of the Aspen field (BP 40% and operator) was concluded in the second quarter of 2003 as part of BP s ongoing portfolio review to focus on high quality assets and to stop investing in those where others may see greater value.

Table of Contents

On January 30, 2004, we sold 45% of our interest in King s Peak in Deepwater Gulf of Mexico to Marubeni Oil & Gas (USA).

On May 22, 2004, the Mars platform was shut in due to a small leak.

Gulf of Mexico Shelf

The Shelf is a mature basin, with decline rates that average 40-50% per year. On March 13, 2003 BP completed the sale of 61 fields to Apache Corporation, which accounted for approximately 40% of 2002 production. In 2003, BP s gas production from Gulf of Mexico Shelf operations was 375 mmcf/d, which was down 44% compared to 2002. Liquids production was 39 mb/d, down 34% compared to 2002. The year-on-year drop in production is attributed to the divestment, normal decline and reduced capital spending. Capital spending has reduced from $428 million in 2002 to $205 million in 2003. This is as a result of our divestment programme as well as focusing our capital expenditure on better opportunities elsewhere in the segment. We operate more than 150 platforms and 350 wells on the Shelf and we drilled a total of 15 operated wells in 2003.

Lower 48 States

In the Lower 48 States we are one of the largest producers of natural gas, accounting for over 5% of total US onshore natural gas production. Production comes from over 12,000 wells, distributed across more than 600 oil and gas fields, of which we operate nearly 80%. Assets are situated principally in the states of Colorado, Kansas, Louisiana, New Mexico, Oklahoma, Texas and Wyoming.

Total production in 2003 was down 10% compared with 2002. Natural decline and strategic portfolio divestments accounted for 3% each and reduced gas throughput and changes in processing elections accounted for the remainder. In 2003, total liquids production was 160 mb/d and natural gas production was 2,109 mmcf/d.

In 2003, we drilled over 400 operated wells and maintained a level programme of activity utilizing, on average, 26 drilling and 50 service rigs. Year-on-year improvements continue to be delivered in safety, capital and cost efficiency across all the basins where we operate. Additionally, our environmental leadership has continued with a 286 kilotonnes (kte) reduction of CO_2 emissions, through delivery of focused greenhouse gas (GHG) reduction projects, including the installation of solar panels to power some of our pumping units at our wells in the San Juan South region.

Our production in the onshore Lower 48 States was derived primarily from two main areas:

In the Western Basins (Colorado, New Mexico, and Wyoming) our assets produced 1,255 mmcf/d (94% operated) of natural gas and 78 mb/d of liquids in 2003.

In the Gulf Coast and Mid-Continental basins (Kansas, Louisiana, New Mexico, Oklahoma and Texas) our assets produced 854 mmcf/d (62% operated) of natural gas and 48 mb/d of liquids in 2003.

Alaska

In Alaska, crude oil production in 2003 was 311 mb/d, an increase of 0.6% from 2002, due principally to increases in Northstar production and development of satellite fields around Prudhoe Bay and Kuparuk.

Table of Contents

Key activities during 2003 in Alaska included:

As part of maximising the productivity of our existing profit centres, active reservoir management at Alaska s largest producing field, Prudhoe Bay, and the associated satellites (BP 26.4% and operator) included an ongoing active infill and new well drilling programme with 80 wells, which generated net production of 8.2 mboe/d. In 2003, BP had 6.5 operated rig-years (6 rigs full time, 1 rig half time) working across the North Slope. At the Milne Point Unit, 20 wells were drilled with 8 miles of horizontal hole achieving 45% lower non-productive time than 2003. The Northstar Unit drilled 8 wells in 2003, and the Endicott Unit drilled 4 sidetrack wells.

The Northstar Oil Field (BP 98.58%) completed its second full year of operations with operating efficiency and production rates well ahead of 2002 levels. Improved equipment reliability and the completion of additional development wells enabled an estimated operating efficiency rate of 86.5% and a daily gross production average of 63 mb/d.

Two agencies completed their investigations into the August 2002 A-22 well explosion with BP s full cooperation. The Alaska Department of Labor Occupational Health and Safety Division assessed a penalty of $6,300 in February 2003, which BP did not contest. The Alaska Oil and Gas Conservation Commission released its staff report on the incident in mid-December and proposed an enforcement action and a penalty in excess of $2.5 million. BP is contesting the penalty.

The Y-36 flowline spill occurred at Greater Prudhoe Bay in May 2003, spilling an estimated 1,300 gallons (US) of crude and 5,000 gallons (US) of produced water. The spill was caused by external corrosion beneath the flowline s insulation. The flowline has since been repaired and there has been no long-term damage to the environment. BP had noted increased corrosion of this type in late 2001 and nearly tripled its mitigation programme in 2003. As operator, BP expends approximately $50 million (gross) annually on corrosion management programmes at Greater Prudhoe Bay.

United Kingdom

We are the largest producer of oil and gas in the UK. In 2003, total liquids production was 377 mb/d, an 18% decrease on 2002, and gas production was 1,446 mmscf/d, a 7 % decrease on 2002. This decrease in production was driven by the divestment during 2003 of the Forties, Montrose/Arbroath and Bacton Area assets to Apache Corporation, Paladin Resources and Perenco, respectively, (49%) along with the natural decline of the mature North Sea basin and operational problems in the second and third quarters (51%). These operational problems included a compressor shutdown on Foinaven (BP operated), well integrity concerns on the Shearwater field (Shell operated) and a gearbox failure on Eastern Trough Area Project (BP operated). All fields were returned to production during the year. 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 $740 million in 2003 compared to $895 million in 2002 and $930 million in 2001.

Significant activities in 2003 included the following:

The Clair Phase I Development (BP 28.9% and operator) is in mid-construction and on schedule for first oil in late 2004.

In 2003, all major construction contracts were awarded for the Rhum development (BP 50% and operator) and fabrication was initiated. Rhum is a high pressure, high temperature gas field that is the first of its type for BP in the region. The field will be developed via a 44 km subsea tieback to the Bruce platforms. Startup is scheduled for 2005.

In 2003, cumulative oil production in the Harding field (BP 70% and operator) and in the Andrew field (BP 62.75% and operator) exceeded the total amounts estimated when the reserves were originally booked. Success in both fields is attributed to the application of new technologies and best practice reservoir management.

The Braemar field (BP 52%) began production at the end of the third quarter, following tie-back to the East Brae platform.

On the Machar field (BP 100% and operator) a project to sustain production by gas lifting the wells was completed and a significant new production well sanctioned for 2004 startup.

At Wytch Farm (BP 67.8% and operator) a seismic survey was shot offshore to define well locations for a 10-well extended reach drilling programme started in 2004.

On the Lomond (BP 22.2% and operator) and Erskine (BP 50%, ChevronTexaco operated) fields, mid-life compression projects have been sanctioned to extend field life. Mid-life compression refers to the installation of compression facilities on the platform which will supplement the natural pressure of the reservoir and thereby increase the flow rate of hydrocarbons.

The Ravenspurn North (BP 53.5% and operator) gas sales contract was renegotiated to transfer the control of production from the buyer to the joint venture partners with effect from October 1, 2003.

A one-off gas sales deal was agreed for Amethyst (BP 59.5% and operator) to increase gas sales during the 2003 summer period.

The NW Hutton (BP 26% and operator) well decommissioning was completed on January 22, 2004 with the removal of the last conductor. The total cost of decommissioning was $17.6 million (BP share).

Rest of Europe

Development expenditure, excluding midstream, in the Rest of Europe was $236 million compared with $219 million in 2002 and $271 million in 2001.

Norway

Production in Norway decreased from 113 mboe/d in 2002 to 92 mboe/d in 2003, a decline of 18%. The principal reasons behind this were: a reduction in Draugen production capacity and delays in restoring production from Rogn South wells following a shutdown; the SE1 well on Ula proved water in the main target rather than oil, hence the anticipated decline mitigation was not achieved; and Tambar, having reached plateau in 2002, was impacted by post-plateau natural decline. The total impact of these items was a decrease of 17 mboe/d. In addition, on September 1, 2003 we sold our 61% interest in the Gyda field to Talisman Energy (6 mboe/d). We have maintained production at 2002 levels on Valhall as a result of the Flank project coming on stream (first oil in the second quarter of 2003) and a high level of operating efficiency.

Main activities and achievements in 2003:

Valhall Water Injection project following technical difficulties in positioning the jacket foundation piles, repairs were successfully carried out and the topside was installed in the third quarter.

Valhall Flank Development Flank South achieved first oil in May 2003 and the North platform was installed in the third quarter with first oil achieved on January 7, 2004.

Ormen Lange The unit operating agreement, plan of development and the joint venture agreements for an export pipeline to the UK were agreed and approved by the partnership in December. BP has a 10.3% interest in this project.

Table of Contents

Rest of World

Development expenditure, excluding midstream, in Rest of World was $3,085 million in 2003 compared with $2,503 million in 2002 and $1,934 million in 2001.

Rest of Americas

Canada

In Canada, our 2003 production was 86 mboe/d, down 18% from 2002, mainly due to natural field decline. 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. BP s production impacted by this order was 1.3 mboe/d on an annualized basis. BP and other producers are pursuing legal and regulatory options challenging the shut-in requirement in addition to seeking appropriate compensation from the Alberta Government. Natural gas makes up 85% of Canada s production.

On February 9, 2004, we signed a sale and purchase agreement with Fairborne Energy Ltd. to sell a package of non-core assets in Alberta, Canada for $88 million. These assets contributed approximately 3 mboe/d during 2003.

Trinidad

In Trinidad, gas volumes increased by 37% over 2002. The increase in natural gas sales was principally driven by the successful startup of Atlantic LNG Train 3 in the second quarter of 2003, as well as a full year of sales to Atlantic LNG Train 2. During the year, BP completed the installation of Cassia B, the world s largest offshore processing facility (2 bcf/d), linked in to the new Bombax 48 gas pipeline evacuation system, which was successfully commissioned in the second quarter of 2003. Our next field development (Cannonball) was sanctioned in the fourth quarter of 2003. First gas is targeted for the fourth quarter of 2005.

On January 2, 2003, Repsol exercised their option to acquire an additional 20% interest in BP s upstream assets in Trinidad, taking their total interest in BP Trinidad and Tobago LLC to 30%. This transaction gives leverage for our upstream position in Trinidad to access gas markets and growth opportunities in Spain, thus providing a further platform for BP s future gas growth in Trinidad.

On May 15, 2003, we sold our 15% stake in the Titan Methanol Company, based in Trinidad, to Methanex Corporation. The Atlas methanol plant the world s largest, in which BP has a 36.9% interest commenced production on June 2, 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 Zuli 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). A fourth asset, Cerro Negro, a non-operated property that is a heavy oil project from which production is sold directly by BP, was held for sale in

2002. In the absence of partner approval for the sale, the agreement was terminated in December 2003. There are no immediate plans to remarket this asset. 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. LL-652, also a reactivation project, was sold and transferred to ChevronTexaco during the year. The impact of the national strike, which began in December 2002, was 5 mb/d in 2003, with production back to pre-strike levels by mid-March 2003.

Table of Contents

Colombia

In Colombia, BP completed operations in November on the Niscota exploration well after testing water with traces of non-commercial hydrocarbons. While this well has been written off, additional prospectivity and disposition of the contract area will be determined in the second half of 2004 after evaluation of data obtained from drilling activities.

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 2003, total production of 117 mboe/d represented an increase of 10.3% over 2002, with oil increasing by 10.4% and gas by 10.2%. 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 52 mb/d compared to 45 mb/d in 2002. The field is now producing at its highest level since inception in 1958 and further expansion programmes are planned. Despite the economic crisis in Argentina, GDP increased by 8.7% in 2003. Gas demand grew due to the higher activity level, colder than normal weather and lack of hydroelectric power due to lower than average rainfall. Gas prices continued to be depressed. PAE also has interests in gas pipelines, electricity generation plants and other midstream infrastructure assets.

Africa

Algeria

In 2003, BP sold 50% and 49% of its interests in In Amenas and In Salah, respectively, to Statoil. Formal Algerian approval is currently outstanding.

In Algeria, BP and the Algerian state company, Sonatrach, continued development activities of the In Salah project (BP 51%), which is expected to start up in mid-2004. The first stage comprises the development of three of the seven deep Saharan natural gas fields expected to supply the fast-growing markets of Southern Europe.

BP and Sonatrach continued to progress the development of the In Amenas (BP 50%) project, expected to start up in early 2006.

Angola

Angola has several key projects which provide the foundation for volume growth over the next few years. Activities in 2003 included the following:

In Block 17 (BP 16.7%), the Jasmim field, a tie-back to the Girassol hub, commenced production in the fourth quarter of 2003. The Dalia project commenced development in the first quarter of 2003.

In Block 15 (BP 26.7%), the Xikomba field commenced production in the fourth quarter of 2003. Development activities progressed on Kizomba A and Kizomba B, with production expected to commence in the second half of 2004 on Kizomba A.

In Block 18 (BP 50% and operator), work has continued on the Greater Plutonio development, with internal sanction granted in the first quarter of 2003.

In Block 31 (BP 26.7% and operator), a 2-year extension to the initial exploration phase was granted in the second quarter of 2003.

Angolan oil projects have associated gas which BP is seeking both economic and environmental solutions for production and distribution as part of the Angola LNG project.

Table of Contents

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 seven PSAs in the Gulf of Suez and Western Desert, encompassing more than forty fields.

In 2003, physical gas production in Egypt was held close to 2002 rates. BP s 2003 PSA gas production reached 253 mmscf/d from the Ras El Barr, Temsah and other concessions.

BP has a 33% interest in the joint venture United Gas Derivatives, currently constructing a 1.1 bcf/d NGL extraction plant. Plant startup is scheduled in the fourth quarter of 2004. Temsah and Ha py development projects are on schedule to deliver 100% of the fields daily contracted quantities to ensure supply feedstock for the NGL plant.

Asia Pacific

Indonesia

BP is the largest private supplier of natural gas to Java through its holdings in the Offshore Northwest Java (46% BP) and Kangean (100% BP) Production Sharing Contracts.

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 (BP 34.3% and operator) supplies, under a long-term contract, 100% of the natural gas requirement of Castle Peak Power Company for Hong Kong power generation. 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. The Yacheng field operatorship was transferred to China National Offshore Oil Corporation (CNOOC) on January 1, 2004. In 2003, we have divested our interests in our other fields, QHD and Liuhua, to CNOOC.

Australia

We are one of six equal partners (BP 16.7%) in the North West Shelf (NWS) Venture. The operation covers offshore production platforms, a floating storage vessel, trunklines, and onshore gas processing plants, and is currently the principal supplier to the domestic market in Western Australia. During 2003, a fourth LNG Train was under construction and is on track to be commissioned in the second half of 2004, and a second trunkline was commissioned in February 2004.

Russia

Acquistion of TNK-BP interest

On August 29, 2003, BP and AAR (the Alfa Group and Access-Renova) completed the deal to combine their Russian and Ukrainian oil and gas businesses and create TNK-BP, a new company registered in the British Virgin Islands owned 50:50 and managed jointly by BP and AAR. The consideration from BP to AAR comprised an immediate $2.6 billion in cash (which was subsequently reduced by receipt of pre-acquisition dividends net of transaction costs of $0.3 billion) for its stake in the new company together with three annual tranches of $1.25 billion in BP shares payable on the subsequent anniversaries of the closing date. The assets contributed by BP included existing interests in Sidanco and Rusia, as well as its interest in the retail business in Moscow. The deal did not include BP s interest in Sakhalin or its Castrol operations in Russia. The net BP investment, after adjusting for pre-acquisition dividends, amounted to $6.7 billion. BP also agreed with AAR to incorporate AAR s 50% interest in Slavneft into TNK-BP in return for a cash payment by BP of $1.35 billion, subject to adjustments. This transaction was completed on January 16, 2004. Overall, this represents the largest transaction in Russian corporate history, as well as being the largest foreign indirect investment in Russia.

TNK-BP is jointly controlled by BP and Alfa Group and Access Renova (AAR). BP holds 50% of the voting rights in TNK-BP. BP s investment in TNK-BP is accounted as a joint venture under the gross equity method and as such we have reflected 50% of the proved reserves of TNK-BP as at December 31, 2003 (1.8 billion barrels of oil, of which 1.4 billion are developed). The reserves which were incremental to those contributed from our investment in Sidanco (1.6 billion barrels of oil) are shown as a purchase of reserves in place in equity-accounted entities. The return on our investment in TNK-BP is expected to come through cash dividends. Earnings for the period August 29 to December 31, were accretive to BP returns on capital and we expect this to continue at current prices. As with our other assets, an increase in oil prices will increase the returns on our investment. Our expected return on this investment in both the short and long term is estimated to be comparable to that of our non-Russian activity.

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 and AAR have equal representation on the TNK-BP Board, with AAR nominating the Chairman and Chairman of the Remuneration Committee, and BP 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.

On June 11, 2004 BP and AAR agreed to change the dates on which BP is due, under the terms of that agreement, to issue AAR with three tranches of BP p.l.c. shares, each tranche with a value of $1.25 billion. The issue dates have been changed from August 29, 2004, August 29, 2005 and August 29, 2006 to September 20, 2004, September 20, 2005 and September 20, 2006, respectively. The issue dates have been moved in order to avoid BP s third quarter ex-dividend date falling within the calculation period for determining the number of BP p.l.c. shares to be issued to AAR in each tranche, thereby reducing the potential for volatility during that period. There is no incremental cost to BP or its shareholders as a result of this change in issue dates.

TNK-BP

TNK-BP has proved reserves of 3.6 billion barrels of oil, of which 2.8 billion are developed. Daily oil production currently amounts to some 1.3 million barrels of oil a day. The production base is largely centred in West Siberia (Samotlor, Nizhnevartovskoye Nefedobyvaushee Predpriyatie, Nyagan), which contributes about 0.8 million barrels a day, together with Volga Urals (Orenburgneft) contributing 0.4 million barrels a day. In excess of 50% of total oil production is currently exported as crude and 15% as refined product. Downstream, TNK-BP owns five refineries in Russia and Ukraine (including Ryazan and Lisichansk), with throughput of 0.5 million barrels a day (25 million tonnes a year). In retail, TNK-BP owns 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 amounts to approximately 100,000 people.

BP s investment in TNK-BP is accounted for under the gross equity method. Production for the four-month post-completion period averaged 713 mboe/d; this generated some $392 million of net income in an environment where Urals marker prices (NW Europe) averaged around $27.3/bbl (from August 29, 2003). In full-year terms, BP s share of production averaged 244 mboe/d. A dividend of $297 million received in the fourth quarter was credited against the net investment cost and reduced net cash outflow to $2.35 billion.

Table of Contents

Slavneft

On January 16, 2004 a payment of $1.35 billion was made to AAR to incorporate AAR s 50% interest in Slavneft into TNK-BP. Slavneft will be included in the results of our 50% interest in TNK-BP in 2004. Slavneft has current production rates exceeding 0.3 million barrels of oil per day. It has two refineries in Russia (Yaroslavl) and an interest in the Mozyr refinery (Belarus) with total throughput of 384,000 barrels a day, as well as more than 550 retail filling stations in Russia.

Other

Middle East and Pakistan

Production in the Gulf States was dominated by the production entitlement of associated undertakings in Abu Dhabi, where we have equity interests of 9.5% and 14.7% in onshore and offshore concessions, respectively. In 2003, production in Abu Dhabi was up around 23% from 2002 as a result of OPEC quota increases.

In Pakistan, BP is the largest foreign operator producing around 43% of the country s oil and 8% 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 continued in 2003 and is on track to deliver first oil from central Azeri in the first quarter 2005. Phase 3 of ACG full field development commenced the detailed engineering stage and is targeting sanction in 2004.

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.

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 BTC operator, manages and holds a 30.1% interest in the Baku-Tbilisi-Ceyhan (BTC) oil pipeline currently under construction. AIOC 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 2003 included:

Alaska

BP owns a 46.9% interest in TAPS, with the balance owned by four other companies. TAPS transported production from Prudhoe Bay and the other North Slope fields averaging 991 mb/d during 2003.

There are a number of unresolved protests regarding tariffs charged for shipping oil through TAPS. These protests were filed between 1986 and 2003 with the Federal Energy Regulatory Commission and the Regulatory Commission of Alaska (RCA). In 2002, the RCA issued an Order requiring refunds to be made to TAPS shippers of intrastate crude oil for the years 1997 through 2000. BP has appealed this Order to the Alaska Superior Court. Pending the outcome of a hearing on intrastate rates from 2001 forward, the RCA imposed temporary intrastate rates (consistent with its 2002 Order) effective July 1, 2003.

The use of US-built and US-flagged ships is required when transporting Alaskan oil to markets in the USA. In accordance with this, BP America Inc. has a chartered fleet of nine US-flagged tankers to transport Alaskan crude oil to markets. Over the next few years, we plan to begin replacing our US-flagged fleet as existing ships 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 on page 69. 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 NASSCO in San Diego with deliveries in years 2004, 2005 and 2006. The first vessel was floated from drydock in November of 2003, in keeping with a 2004 delivery.

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 2003 at 751 mb/d.

During the fourth quarter of 2003, FPS reached agreement with Encana and others to transport and process hydrocarbons from the Buzzard Field. This is the largest UK sector transportation and processing deal in the last 10 years.

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, Northeast England. CATS offers natural gas transportation services or transportation and processing via two 600 mmcf/d processing trains. In 2003, throughput was 1.6 bcf/d.

In addition, BP operates the Dimlington/Easington gas processing terminal (BP 100%) on Humberside and the Sullom Voe Gas Terminal in the Shetlands, which celebrated 25 years of operations in November 2003.

Asia (including the former Soviet Union)

BP, as BTC operator, manages and holds a 30.1% interest in the Baku-Tbilisi-Ceyhan (BTC) oil pipeline which is currently under construction and is on schedule to be ready for line fill by early 2005.

The South Caucasus pipeline (SCP) for the transport of gas from Shah Deniz in Azerbaijan to the Turkish border was sanctioned in February 2003. BP is the operator and holds a 25.5% interest.

Through the LukArco joint venture, BP holds a 5.75% interest 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 on budget at a gross cost of $2.6 billion. 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 in CPC through a 49% holding in Kazakhstan Pipeline Ventures.

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. It will be the largest capacity deepwater pipeline ever built.

Liquefied Natural Gas

Within BP, Exploration and Production is responsible for the supply of LNG and Gas, Power and Renewables is responsible for the subsequent marketing and distribution of LNG (see details under Gas, Power and Renewables New Market Development and LNG on page 45).

Significant activity during 2003 included the following:

We have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2003 supplied 5.4 million tonnes (263 bcf) of LNG, up 2% on 2002.

In Australia, we are one of six equal partners (BP 16.7%) in the North West Shelf Venture. The joint venture operation covers offshore production platforms, a floating storage vessel, trunklines, and onshore gas processing plants. During 2003, a fourth LNG Train and second trunkline were under construction and are expected to be commissioned in 2004.

In Indonesia, BP participates in Indonesia s LNG exports through its holdings in the Sanga-Sanga (BP 38%) PSA. Sanga-Sanga delivers around 30% of the total gas feed to the Bontang LNG plant.

In addition, we have interests in the Wiriagar (BP 38% and operator), Berau (BP 48% and operator) and Muturi (BP 1%) PSAs in Northwest Papua. These PSAs will provide the natural gas feed to the Tangguh LNG project (BP 37% and operator), which is expected to become the third LNG centre in Indonesia. In 2003, as part of our strategy to serve gas markets in Southern China, we sold 12.5% of our Tangguh share to CNOOC. During 2003, BP continued to actively pursue LNG sales opportunities and secure lender commitment for the Tangguh development.

In Trinidad, Atlantic LNG Train 3 (BP 42%) was commissioned in the second quarter. In June 2003, the government of Trinidad and Tobago approved the Atlantic LNG Train 4 project - one of the largest LNG production plants in the world with a capacity of 5.2 million tonnes (253 bcf) per annum of LNG production. Train 4 is currently under construction and due to start up at the end of 2005.

Table of Contents

GAS, POWER AND RENEWABLES

The strategic purpose of the Gas, Power and Renewables segment is to maximize the value of BP s gas through marketing, to enhance the value of BP s natural gas liquids production and to build a profitable renewables business.

The segment is organized into four main activities: marketing and trading; natural gas liquids (NGL); new market development and LNG; and solar and renewables. 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 include 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. BP is currently a partner in the construction of a gas processing plant, NGL storage and export facilities in Egypt which has also been transferred to this segment. The total operating profit for these transferred assets was $106 million in 2003, but the data below has not been restated to include this amount.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Turnover	65,445	37,357	39,442
Total operating profit	478	405	407
Total assets	10,260	6,927	5,775
Capital expenditure and acquisitions	359	408	492

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 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 company 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. BP continues to pursue the development of hydrogen fuel technology.

Table of Contents

Capital expenditure and acquisitions for 2003 was $359 million compared with $408 million in 2002 and $492 million in 2001. Excluding acquisitions, capital expenditure for 2003, 2002 and 2001 was $359 million, $335 million and $352 million, respectively. Capital expenditure excluding acquisitions for 2004 is planned to be around $600 million (including the NGL activity transferred from the Exploration and Production segment on January 1, 2004); the increase over the 2003 level is due to higher spending on the Guangdong terminal in China and the power project in Korea.

Marketing and Trading Activities

Our gas marketing and trading activities are concentrated in the markets of North America and the United Kingdom. Gas sales volumes have increased from 18.8 billion cubic feet per day (bcf/d) in 2001 to 21.6 bcf/d in 2002 and 26.3 bcf/d in 2003. Most of this growth was realized in the USA and Canada. Canada volumes are reported in the Rest of World volumes.

	Years ended December 31,		
Gas sales volumes (a)	2003	2002	2001
	(million cubic feet per day)		
UK	2,631	2,372	2,641
Rest of Europe	441	399	213
USA	11,528	9,315	8,327
Rest of World	11,669	9,535	7,613
Total	26,269	21,621	18,794

(a) Includes marketing, trading and supply sales.

Our policy toward natural gas price risk is described in Item 11 Quantitative and Qualitative Disclosures about Market Risk on page 175.

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 13.4 bcf/d in 2001 to 16.1 bcf/d in 2002 and to 20.6 bcf/d in 2003. Of these sales volumes, 4.1 bcf/d was supplied from BP upstream producing operations in 2001, 4.0 bcf/d in 2002 and 3.6 bcf/d in 2003. The decline in BP production in 2003 was primarily due to the divestment of various properties.

Our North American natural gas marketing and trading strategy seeks to provide unconstrained market access for BP s equity gas, increase margin through targeting higher value customer segments and optimizing around our network of connected assets to reduce cost of goods sold. 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 2.6 bcf/d in 2003, 2.4 bcf/d in 2002 and 2.6 bcf/d in 2001. Of these volumes, 1.5 bcf/d (2002 1.6 bcf/d and 2001 1.7 bcf/d) were supplied by BP s Exploration and Production operations. The majority of natural gas sales are to commercial and industrial customers, 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.

We have a 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, which effectively links the natural gas markets of the UK and continental Europe.

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 number two behind the incumbent Gas Natural. 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,		
NGL sales volumes	2003	2002	2001
	(thousand barrels per day)		
UK			
Rest of Europe			
USA	164	196	221
Rest of World	182	214	189
Total	346	410	410

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 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 8.2 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.

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

Table of Contents

expansions of existing LNG plants in Trinidad and Tobago, the North West Shelf in Australia and greenfield developments such as Tangguh in Indonesia.

In April 2003, a third LNG train commenced operations in Trinidad, with initial deliveries to Lake Charles, Louisiana and, following Federal Energy Regulatory Commission (FERC) approval, to the Cove Point regasification facility in Maryland. BP has capacity access at the Cove Point terminal, which was officially commissioned in August and is operated by Dominion Resources. The Government of Trinidad and Tobago announced in June 2003 its approval for the Atlantic LNG Train 4 project in Trinidad. BP will be the largest shareholder in the new plant as well as the largest supplier of gas for liquefaction at the plant.

At Bilbao, northern Spain, construction was completed on Europe s first integrated LNG regasification and power generation complex (BP 25%). In November, BP signed a six-year sales and purchase agreement with Oman LNG who will supply 3.6 million tonnes (175 bcf) of LNG over the contract term starting in 2004. The shipments are intended for BP customers in Spain.

The Tangguh LNG project (BP 37.2%) in Indonesia was selected as the preferred supplier of LNG to two South Korean companies SK Power Company Limited and POSCO in what is the world s fastest growing LNG market. POSCO is the world s second largest steel maker and SK Power, at the time, was 100% owned by SK Corporation (SK Corp), South Korea s largest oil refiner. The bid process to purchase LNG was the first undertaken by South Korea s private sector and is for the supply of up to 1.35 million tonnes per annum (66 bcf per annum) of LNG for a 20-year term starting in 2005.

In late December 2003, BP and BPMIGAS, Indonesia s executive agency for oil and gas, signed a Heads of Agreement with Sempra Energy LNG Corp. for a 20-year supply of LNG from Indonesian sources to markets in the US and Mexico. Under the agreement, 3.7 million tonnes of LNG per annum (180 bcf per annum) will be delivered from the Tangguh fields over a period of 15 years beginning in 2007 to Sempra s proposed LNG import and regasification terminal near Ensenada in Baja California, Mexico. Sempra s terminal, when completed, will have the capacity to process up to 1 bcf/d of natural gas. During 2004, the parties to the Agreement intend to negotiate a definitive agreement.

The successful Tangguh supply bids are in addition to the LNG sales contract secured in 2002 for 2.6 million tonnes per annum (127 bcf per annum) for the Fujian LNG project in China commencing in 2007. The Tangguh project now has agreements in various stages of completion for 7 million tonnes per annum (341 bcf per annum).

In Southeast China, the feasibility study report for the Guangdong LNG project (BP 30%) has been approved by the Chinese Government and the contract to form a joint venture company to construct the terminal and trunkline was signed in February 2004. 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%).

BP and Sonatrach announced in October 2003 that they are to form a joint venture that will provide the first new supplies of LNG to the UK market with scope to expand the arrangement to the US and other markets. The two companies were also successful in bidding for the long-term capacity rights in the Isle of Grain import regasification facility which is being developed on the Medway River, 20 miles east of London and which is owned and operated by National Grid Transco (NGT). The capacity rights will enable the two companies to source and then supply around 3.7 million tonnes per annum (182 bcf per annum) of LNG into the UK market from 2005 representing approximately 5% of UK demand.

In December 2003, BP submitted its pre-filing request to FERC to construct an LNG regasification terminal located on the Delaware River in the state of New Jersey. This was approved in early January

Table of Contents

2004. The pre-filing process is a collaborative approach, coordinated by FERC, under which the various federal and state agencies having jurisdiction are engaged in the process, along with other potential stakeholders. The Project anticipates receiving final FERC approval in the middle of 2005. This timing should allow BP to begin construction during the third quarter of 2005 with a view to beginning terminal operation during the second half of 2008.

In March and June 2003, BP took delivery of the second and third of three new leased LNG ships from Samsung Heavy Industries in Korea. These ships are mainly employed in supplying our BP customers in Spain with supply from ADGAS and Qatar under short-term contracts signed in 2002. Our first LNG ship, the British Trader celebrated its first full year of service in mid-November and is mainly employed in lifting LNG cargoes from Trinidad and delivering to the US.

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 has repositioned BP Solar in order to improve business performance. A number of specific restructuring measures have been 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, staff and other overhead reductions across the global business and restructuring provisions related to improving the overall efficiency of the business. In addition, BP completed its exit from the manufacture of thin film solar products (announced in 2002). This will allow the Group to focus on core markets supported by global technology and manufacturing functions.

Our solar energy business in 2003 grew 6% to 71 megawatts (MW) of solar panels generating capacity (2002, 67 MW). This growth rate was lower than historical rates due to a near-term focus on restructuring the business. BP began production in its new 30 MW facility in Madrid, Spain in 2003.

Our Home Solutions programme, an extension of our brand directly into California, New York and New Jersey residential markets, was launched in 2003. It successfully generated awareness around the benefits of solar and is expected to result in over 400 new installations of solar electric systems.

During 2003, BP successfully reached agreement with the Phillipines Department of Agricultural Reform to begin the installation of specific solar packages on 79 Agrarian Reform Communities (ARC) in the region of Mindanao, targeted at improving social welfare, increasing agricultural productivity and empowering local ARC and farmer s organizations. The solar packages include lighting and electricity supply, vaccine refrigeration, potable water provision, communal lighting, etc.

We are building expertise in wind energy and implementing wind projects on selected BP sites. In 2002 we started up our 22.5 MW wind farm at the Nerefco oil refinery (both the refinery and wind farm are jointly owned with ChevronTexaco (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 entered commercial operation.

Table of Contents

In December 2003, BP announced that it would acquire a 35% interest in SK Power, a company that was established to develop, finance, construct and operate a 1,074 MW gas-fired combined cycle power plant located in Kwangyang Province, South Korea. This was subsequent to the selection of the Tangguh LNG project as preferred supplier of LNG to SK Power and POSCO, which is detailed in the New Market Development and LNG section above. SK Corp will retain the remaining 65% interest in the power plant, the total cost of which is expected to be around $600 million and is expected to commence operations in 2006.

We have two further power generation construction projects underway. A 50 MW cogeneration plant is under construction near Southampton, UK (BP 100%), and a 570 MW cogeneration plant as part of a 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 petrochemical complex. BP will supply natural gas to the Texas City plant and will use the excess generation capacity to support power marketing and trading activities.

We own a 400 MW gas-fired power plant at Great Yarmouth in the UK (BP 100%). We are operating the plant and selling electric power, with BP providing the natural gas to the plant.

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.

48

Table of Contents

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,		
	2003	2002	2001
		($ million)	
Turnover (a)	149,477	125,836	120,233
Total operating profit	2,292	1,921	1,990
Total assets	60,088	55,815	43,553
Capital expenditure and acquisitions	3,080	7,753	2,415
		($ per barrel)	
Global Indicator Refining Margin (b)	3.88	2.11	4.06

(a) Excludes BP s share of joint venture turnover of $453 million in 2003, $415 million in 2002 and $403 million in 2001.

(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 grow through 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 of high quality assets to our operations.

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.

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.

Table of Contents

In March 2004, BP and the Singapore Petroleum Company Limited (SPC) announced that conditional agreement had been reached for SPC to purchase BP s interests and one-third stake in Singapore Refining Company Private Limited (SRC) for $140 million. Subsequent to this announcement we were notified that the remaining shareholders wished to exercise their preemption rights. This will result in BP s one-third share being divided equally between the two remaining shareholders in SRC, namely Caltex Singapore Private Ltd and SPC. As a result, these two companies will also acquire BP s one-sixth equity interest in Tanker Mooring Services Company Pte Ltd (TMS). The transaction is expected to be concluded in mid-2004.

In the first quarter of 2004, BP and Lembaga Tabung Angkatan Tentera (LTAT) announced that agreement had been reached for LTAT to purchase BP s 70% shareholding in the BP Malaysia Sdn Bhd fuels business. Subject to receiving the necessary regulatory consents, this transaction is expected to be concluded during the third quarter of 2004.

The decision to divest the Singapore and Malaysian fuels business is part of BP s global strategy of concentrating on markets and segments where we believe we can obtain scale and build a significant presence. The sale has no impact on BP s other activities in Malaysia.

Capital expenditure and acquisitions in 2003 was $3,080 million compared with $7,753 million in 2002 (including $5,038 million for the Veba acquisition) and $2,415 million in 2001. Excluding acquisitions, capital expenditure was $3,006 million in 2003 compared with $2,682 million in 2002 and $2,386 million in 2001. Capital expenditure excluding acquisitions is expected to be around $2.8 billion in 2004.

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.

In December 2003, we announced the sale of our European Special Products business, including the Neuhof base oil refinery in Hamburg, Germany. The sale was completed in January 2004.

In June 2004, the shareholders of the ATAS Refinery (Anadolu Tasfiyehanesi A.S.) in Mersin, Turkey announced that the refinery will continue its operations as a fuels supply terminal henceforth. ATAS will commence a process to change its operations to become a terminal in early September 2004 and will be operated by the same partners and continue to supply petroleum fuels to southern Turkey.

Table of Contents

The following table summarizes the BP Group interests and crude distillation capacities (at December 31, 2003):

	Refinery	Group interest (b) %	Crude distillation capacities (a) (mb/d) 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	267	60
	Gelsenkirchen*	50.00	272	136
	Karlsruhe	12.00	308	37
	Lingen*	100.00	87	87
	Neuhof*	100.00		
	Schwedt	18.75	221	42
Netherlands	Nerefco*	69.00	400	276
Spain	Castellón*	100.00	110	110
Turkey	Mersin* (c)	68.00	100	68
Total Rest of Europe			2,067	1,048
USA				
California	Carson*	100.00	260	260
Washington	Cherry Point*	100.00	232	232
Indiana	Whiting*	100.00	420	420
Ohio	Toledo*	100.00	155	155
Texas	Texas City*	100.00	470	470
Total USA			1,537	1,537
Rest of World				
Australia	Bulwer*	100.00	92	92
	Kwinana*	100.00	139	139
New Zealand	Whangerei	23.66	109	25
Singapore	SRC*+	33.00	248	82
Kenya	Mombasa	17.00	90	15
South Africa	Durban	50.00	182	91
Total Rest of World			860	444
Total			4,843	3,408

* Indicates refineries operated by BP.

Indicates lubricants refinery which does not have crude distillation capacity. The sale of our interest in this refinery was completed in January 2004.

\+ The sale of our interest in this refinery was announced in March, 2004.

Table of Contents

(a) Gross rated capacity 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.

(c) The closure of the refinery and transformation to a fuels terminal was announced in June 2004.

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,		
	2003	2002	2001
Refinery throughputs (a)	(thousand barrels per day)		
UK	397	389	364
Rest of Europe	932	918	663
USA	1,386	1,439	1,526
Rest of World	382	357	376
	3,097	3,103	2,929
For BP by others		14	14
Total	3,097	3,117	2,943
Refinery capacity utilization			
Crude distillation capacity at December 31, (b)	3,408	3,534	3,259
Crude distillation capacity utilization (c)	91%	91%	94%
United States	91%	93%	95%
UK and Rest of Europe	90%	91%	94%
Rest of World	94%	85%	93%

(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 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.

Capacity utilization in the US was affected by various power outages and the hurricane Claudette during 2003.

Table of Contents

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.

The following table sets out refined product sales by area.

	Years ended December 31,		
Sales of refined products (a)	2003	2002	2001
	(thousand barrels per day)		
Marketing sales:			
UK (b)	271	253	266
Rest of Europe	1,316	1,467	1,062
USA	1,797	1,874	1,866
Rest of World	648	586	603
Total marketing sales (c)	4,032	4,180	3,797
Trading/supply sales (d)	2,692	2,383	2,409
Total refined products	6,724	6,563	6,206
	($ million)		
Proceeds from sale of refined products	102,003	87,520	82,241

(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:

Years ended December 31,

Marketing sales by product	2003	2002	2001
	(thousand barrels per day)		
Aviation fuel	532	529	515
Gasolines	1,694	1,744	1,659
Middle distillates	1,199	1,232	1,077
Fuel oil	312	451	351
Other products	295	224	195
Total marketing sales	4,032	4,180	3,797

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.

BP s marketing sales volumes were lower in 2003 mainly due to planned portfolio changes. The planned portfolio impacts were the sale of Veba retail sites in Germany, the sale of retail sites in Cyprus and the transfer of retail sites in Russia to TNK-BP.

Table of Contents

Retail

Success in retail relies on having superior locations, a superior offer, and executing that offer well, time after time. Our strategy is to focus our capital into the best locations in the 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.

We are working to make our offer continuously more attractive to customers so that they come preferentially to BP. There are two components of our retail offer. The convenience offer, where we sell convenience items to customers from advantaged locations in metropolitan areas and the fuel offer, which we deploy in all our markets, in many cases without the convenience offer. We have a high quality shop offer in each of our key markets, whether it is the new BP Connect offer in Europe and the Eastern USA, am/pm west of the Rocky Mountains, or the Aral offer in Germany. Each of these brands carries a very strong offer itself, but we are also sharing best practices between them. We have also upgraded our fuel offer with the introduction of Ultimate gasoline and diesel, which have greater efficiency and power and lesser environmental impacts. We launched the new fuels in UK, Spain, Greece and three markets in the United States during the past year.

Our strategic focus has resulted in investment in our convenience offer through increased numbers of BP Connect sites and in our premium fuels offer with the rollout of BP Ultimate diesel and gasoline. This strategic focus will continue going forward with roll-out of our convenience and premium fuels offers in high-growth metropolitan markets where we can be number one or two.

Our focus on operational efficiencies through targeted programmes of performance improvement has allowed us to increase our fuel throughput per site and increase our store sales per square metre. This strategic focus on executing excellence will continue going forward as we target increased fuel and store efficiencies.

Across the network, our large format stores achieved store sales growth above the market average, and we plan to invest primarily in additional store space on existing real estate in our core metropolitan convenience markets. During 2003, our same store sales across Australia, Europe and the USA grew 3%, a lower rate than the previous year driven by overall weaker economic growth. Same site fuel volumes grew in these areas by 0.5%.

	Years ended December 31,		
Shop sales (a)	2003	2002	2001
		($ million)	
UK	567	527	458
Rest of Europe	3,000	2,638	904
USA	1,620	1,585	1,510
Rest of World	521	421	362
Total	5,708	5,171	3,234
Direct managed	2,090	1,869	1,650
Franchise	3,508	3,216	1,504
Shop alliances	110	86	80

Total	5,708	5,171	3,234

(a) Shop sales reported are sales through direct-managed stations, franchises and the BP share of shop alliances and joint ventures. Sales figures exclude sales taxes and lottery sales but include quick service restaurant sales.

Table of Contents

Our retail network is largely concentrated in Europe and the USA, with established operations in Australasia, Southeast Asia and Southern Africa. We are developing networks in China and Mexico. In 2003, we concluded the mandatory divestments of about 800 stations in Germany following the acquisition of the Aral network (approximately 3,200 service stations in Germany and Central Europe) in 2002. The rationalization of the portfolio includes the divestment of the Aral-branded sites in Slovakia and Hungary.

BP s worldwide network consists of approximately 28,000 stations branded BP, Amoco, ARCO and Aral. Whilst in Austria and Poland all sites have now been rebranded to BP, in Germany the network is about to become single branded Aral. As planned, the 41 stations in which we have an interest in the Moscow metropolitan area have become part of TNK-BP, our Russian joint venture, with effect from the third quarter of 2003.

BP expects its total number of service stations 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. During 2003, further portfolio upgrading has been concluded by divesting sites and networks.

In 2003 we accelerated our rollout of BP Connect sites primarily 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 featuring our branded BP Connect offer 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 remodelling has taken place. At December 31, 2003, 496 BP Connect stations were open (this count reflects the transfer of 41 sites to TNK-BP). In addition the number of stations with the new BP Helios design increased by about 6,300 during 2003 to a total of 16,745.

At December 31, 2003, BP s retail network in the USA comprised approximately 14,700 service stations of which approximately 10,600 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 5,100 in 2003.

In the UK and the Rest of Europe, BP s network comprised about 9,500 service stations at December 31, 2003. In 2003 we opened 49 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 2003.

Our distinctive fuel product offer has expanded through the launches of our BP Ultimate gasoline and diesel products in Greece, Portugal, Spain and the UK and expansion across the network in the USA and Australia.

At December 31, 2003, BP s retail network in the rest of the world comprised some 3,600 service stations. Our established networks are primarily in Australia, New Zealand, Southern Africa and Southeast Asia. BP is growing in China through two strategic alliances. BP s joint venture with PetroChina in Guangdong Province in the coastal region of China had 400 stations at December 31, 2003. BP has agreed in principle with Sinopec to form a second alliance through a joint venture to acquire, revamp or build 500 fuels service stations in the Zhejang Province, in Eastern China. The Sinopec joint venture is expected to start development of sites in 2004, subject to obtaining government approvals.

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.

Table of Contents

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 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

Our 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. 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.

Our aviation business sells fuels and lubricants to airlines and general aviation customers, as well as providing technical services to airlines and airports. During the last few years, our aviation business has strengthened its position in established markets and pursued opportunities in new or emerging markets. The business now markets in approximately 95 countries and is the third largest jet fuel supplier globally.

Our liquefied petroleum gas (LPG) businesses sell bulk, bottled, automotive and wholesale products to a wide range of customers in over 20 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 2003, we continued to grow our LPG business in China, where we now have sole ownership over three key importing facilities in the important markets of Eastern and Southern China. With imports of over 1.5 million tonnes in 2003 and the capacity to grow to 2.5 million tonnes per annum, BP is now the number one importer of LPG into the China market.

In our marine business, we supply lubricants and fuels on a global basis to major shipping companies as well as to smaller operators. We are the leading global participant in the marine lubricants market where we operate in over 800 ports, have offices in 40 countries and supply points in 80 countries.

In our specialized industrial segment, we supply metal-working fluids and lubricants alongside a range of business services, such as fluid management, to equipment manufacturing customers. We also have a significant high performance industrial lubricants business in some key markets.

Our European Business Marketing (EBM) business comprises a portfolio of Business to Business, Business to Consumers, Bitumen and certain Cards activities throughout Europe. Thus, EBM supplies commercial and industrial customers and private end consumers with fuel oil, motor spirit, diesel, heating oil and lubricants. EBM also offers a fuel and service card for fleet and truck customers, as well as supplying industrial customers with bitumen for the road and roof industries.

Table of Contents

Supply and Trading

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

Refer to Item 11 Quantitative and Qualitative Disclosures About Market Risk on page 170 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. It also has interests in a number of crude oil and product pipelines in the UK, the Rest of Europe and 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.

In September, our BP Pipelines business closed the transaction for the sale of 90% of its Cushing to Chicago Pipeline System (CCPS) to Enbridge retaining 10% in line with Pipeline strategy to maximize the value of our assets.

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 and third-party customers.

Excluding BP companies in the USA, at December 31, 2003 the Group controlled or operated an international fleet of twenty-eight oil tankers and eight LNG ships, with capacity of approximately 1.08 million cubic meters. The Group had four Very Large Crude Carriers, fourteen Medium Crude Carriers, nine Product Carriers, and one North Sea shuttle tanker. It also operated three LNG carriers to trade globally, four LNG carriers for Abu Dhabi contracted gas and one LNG carrier for the Western Australia North West Shelf (NWS) project. BP holds an interest in six NWS gas carriers, of which this is one.

BP companies in the USA had seven Large Crude Carriers, three Medium Crude Carriers, and four Product Carriers totalling approximately 1.4 million dead weight tonnes (dwt) on long-term charter. BP owns four barges totalling 0.1 million dwt.

BP is in the middle of a new building programme, which saw 12 leased ships delivered into service in 2003.

These ships will be manned by either BP Maritime Services personnel or by those from a third party who provide the manning services for some of our new ships, whilst operating 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.

Table of Contents

PETROCHEMICALS

Our Petrochemicals business is a major producer of chemicals and plastics through subsidiaries, joint ventures and associated undertakings. The petrochemicals segment is 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,		
	2003	2002	2001
		($ million)	
Turnover (a)	16,075	13,064	11,515
Total operating profit	623	541	(102)
Total assets	17,649	16,595	15,098
Capital expenditure and acquisitions	775	823	1,926
		($/tonne)	
Chemicals Indicator Margin (b)	112	104	109

(a) Excludes BP s share of joint venture turnover of $434 million in 2003, $511 million in 2002 and $102 million in 2001.

(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, plastic fabrications, poly alpha-olefins (PAOs), anhydrides, engineering polymers and carbon fibres, speciality intermediates and the remaining parts of the solvents and acetyls businesses. This measure is not BP specific, rather it is an indicator of relative industry profitability and BP s actual margins will differ. While not entirely representative of BP s complete range of products, we believe it does provide investors with useful information about the environment for BP s products.

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 PTA, PX and acetic acid, and Olefins and Derivatives (O&D) comprising ethylene and related co-products, polypropylene, HDPE and acrylonitrile. On April 27, 2004, we announced our intention to set up a separate corporate entity for the O&D businesses. It is our intention to make a public offering of this new entity at an appropriate time. Based on the estimated lead-time required for such a transaction, and depending on market circumstances, we are aiming to make such an offering in the second half of 2005. We intend to retain and grow the A&A businesses, which will be transferred to the Refining and Marketing segment on 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, as well as textiles for clothes and carpets. 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 2003:

- In January, we commissioned a new 350-ktepa PTA plant at Zhuhai in southern China.
- In April, China American Petrochemical Company (CAPCO), a BP associated undertaking in Taiwan, started producing from its new 700-ktepa PTA unit.

Table of Contents

BP increased the investment in our South Korean and Taiwanese joint ventures. BP acquired an incremental 9% interest in CAPCO to obtain a 59% holding and increased our ownership from 35% to 47% in Samsung Petrochemicals Company (SPC).

BP Solvay Polyethylene North America and its joint venture partners started a new and more efficient High Density Polyethylene (HDPE) plant at Cedar Bayou and discontinued BP Solvay Polyethylene North America s higher cost unit at Deer Park, Texas.

The Shanghai Ethylene Cracker Complex (SECCO) (BP 50%) is on schedule to start up during 2005. At the end of 2003, construction was approximately 50% complete.

BP Solvay Polyethylene Europe (BP 50%) commenced full-scale production from the newly constructed HDPE plant at Lillo, Belgium.

Capital expenditure and acquisitions in 2003 was $775 million compared with $823 million in 2002 and $1,926 million in 2001. Excluding acquisitions, capital expenditure was $775 million, $810 million and $1,446 million respectively. Capital expenditure excluding acquisitions is expected to be around $900 million in 2004.

Significant divestment activities during 2003:

During the second quarter, we divested PT Petrokimia Nusantara Interindo (PT Peni) (BP 75%), a polyethylene joint venture in Indonesia.

In March 2003, we announced our intention to sell our wholly owned specialty intermediate chemicals businesses including trimellitic anhydride (TMA), purified isophthalic acid (PIA) and maleic anhydride (MAN). The sale was completed on May 28, 2004.

Businesses outside of our A&A and O&D portfolios, their co-products, and closely related activity have been reviewed for sale, and to this end we announced in late March 2004 our intention to sell our Fabrics and Fibres and our LAO/PAO businesses. The LAO/PAO businesses may be included in the intended public offering of our O&D business.

During 2003, overall BP petrochemicals production capacity grew 2%.

The following table shows BP production capacity in kilotonnes per annum (ktepa) by product and by region at December 31, 2003.

	UK	Rest of Europe	USA	Rest of World	Total
Capacity by region (a)					
PTA		1,027	2,481	3,363	6,871
PX		482	2,320		2,802
Acetic acid	781		491	926	2,198

Ethylene and related co-products	1,575	4,198	2,246	64	8,083
Polypropylene	270	1,052	1,371		2,693
HDPE	165	618	490	184	1,457
Acrylonitrile/Acetonitrile		300	792		1,092
Other	1,839	4,926	2,221	301	9,287
Total	4,630	12,603	12,412	4,838	34,483

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

Table of Contents

BP is the world s third largest petrochemicals company in terms of production capacity, and currently manufactures and markets about 28 million tonnes of products each year.

As a result of growth and portfolio management, our seven core products now account for 70% of our capital employed.

The seven core products within our portfolio are:

Aromatics and Acetyls

Purified Terephthalic Acid (PTA)

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 59.02%), 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 2003, BP Zhuhai (BP 85%) commissioned a 350-ktepa unit in southern China and CAPCO started up their new 700-ktepa unit in Taichung, Taiwan. Both projects use BP s proprietary PTA technology and were delivered safely, on budget and on time.

BP increased the investment in our Korean and Taiwanese joint ventures. BP acquired an incremental 9% interest in CAPCO to obtain a 59% holding and increased our ownership from 35% to 47% in SPC. As a result, BP s equity PTA capacity in Asia has increased by 14% to around 3 million tonnes a year.

We announced in early June that, due to market factors, we have decided to delay the final sanctioning of the proposed new world-scale PTA plant at Geel in Belgium. We will continue to explore potential options for further developing this project as and when the business environment improves. BP remains committed to the PTA business in Europe.

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 350,000 tonnes per year to 1.2 million tonnes per year.

Paraxylene (PX)

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.

Table of Contents

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%) continued to progress in 2003 and is on schedule to start up around mid 2005. Engineering contracts were awarded at the end of 2003.

- BP Petronas Acetyls Sdn. Bhd. (BP 70%) completed a debottleneck project in Kertih, Malaysia in the first quarter of 2003 which increased capacity to 500 ktepa.

- Expansion of Yangtze River Acetyls Company (Yaraco), China has progressed. The engineering, procurement and construction contract was awarded by BP in early 2004. Target expansion to 350 ktepa is planned to be completed by early 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 completion of the plant is projected at the end of 2006.

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 BP Refining and Petrochemicals (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

During 2003, we continued to integrate the former Veba operations into our own. The company changed its name to BP Refining and Petrochemicals (BPRP) from Veba Oel Refining and Petrochemicals (VORP).

The construction of the 900-ktepa cracker complex in Shanghai by SECCO (BP 50%) progresses smoothly. By early 2004, construction was approximately 50% complete and is on schedule to startup in 2005.

In the USA, construction began on a project to increase ethylene capacity at Chocolate Bayou, Texas by 295 ktepa.

Table of Contents

Polypropylene

Polypropylene is used for moulded products, fibres and films. We are the second largest producer of polypropylene in the world, with 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 petrochemicals complex in Shanghai, planned by SECCO (BP 50%), is expected to add 250 ktepa of polypropylene when completed in 2005.

High Density Polyethylene (HDPE)

Polyethylene is used for packaging, pipes and containers. BP Solvay Polyethylene Europe (BP 50%) has HDPE plants at Grangemouth, UK; Lillo, Belgium; Sarralbe and Lavéra, France; and Rosignano, Italy. In addition, BP Solvay Polyethylene North America (BP 49%) 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

- BP Solvay Polyethylene North America (BP 49%), along with joint venture partner Chevron Philips Chemical Company, started a new 317-ktepa world scale HDPE plant (BP 25%) at Cedar Bayou, Texas. As a result, BP Solvay Polyethylene North America discontinued a 118-ktepa plant of smaller and less efficient capacity at Deer Park, Texas.

- The sale of PT Peni (BP 75%), a 450-ktepa polyethylene plant in Merak, Indonesia was completed in April.

- Exit of Bataan Polyethylene Company plant (BP 39%) continued to progress in 2003.

- The complex in Shanghai, planned by SECCO (BP 50%), is expected to add 600 ktepa of HDPE/linear-low density polyethylene (LLDPE) 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. Green Lake, with a capacity of 460 ktepa, is the largest acrylonitrile production site in the world. Acrylonitrile is also produced at Köln, Germany and through a capacity rights agreement with Sterling Chemicals at Texas City, Texas. Additionally, BP is the world s largest producer and marketer of the co-product, acetonitrile, primarily sold for pharmaceutical applications.

Major Activities

The planned SECCO complex in Shanghai (BP 50%) is intended to produce 260 ktepa of acrylonitrile when complete in 2005.

62

Table of Contents

Other Products

In addition to the seven core products, we are involved in a number of other linked products. These include LLDPE and low density polyethylene (LDPE) which are used in a wide range of applications including packaging, as is styrene. Ethylene oxide and ethanol are all 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. PIA is used for isopolyester resins and gel coats. Napthalene dicarboxylate (NDC) is used for photographic film and specialized packaging. Polybutene is used in lubricants and fuel additives. TMA is used by the automotive and consumer goods industries. Butanediol (BDO) is used in synthetic materials and engineering plastics. MAN is used in a wide range of plastics and resins. Ethyl acetate and vinyl acetate monomer (VAM) are used in coatings and textile applications. Polypropylene resins are also converted into woven and non-woven fabrics for industrial products, such as, carpet backing, geo-textiles and various packaging materials.

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.

PIA is produced at Joliet, Illinois in the USA and in Geel, Belgium. NDC is produced at our plant in Decatur, Alabama in the USA.

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.

TMA and MAN are produced at Joliet, Illinois in the USA. We manufacture BDO using our proprietary technology in a world-scale plant at Lima, Ohio in the USA.

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

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 March 2003 we announced our plan to sell our wholly-owned TMA, PIA and MAN business in Joliet, Illinois in the USA and PIA produced at our integrated aromatics and derivatives complex in Geel, Belgium. The sale was completed on May 28, 2004.

We sold our share in AG International Chemicals Company (BP 50%), a joint venture with Mitsubishi Gas Chemical Company in Japan manufacturing PIA.

We completed the divestment of Burmah Castrol Chemicals with the sale of Fosroc Mining and Sericol in January 2003.

We exited the ethylene vinyl acetate copolymers (EVA) business at Köln, Germany.

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

In March 2004, we announced our intention to sell our Fabrics and Fibres and our LAO/PAO businesses. The LAO/PAO businesses may be included in the intended public offering of our O&D business.

On April 27, 2004, we announced our intention to set up a separate corporate entity for the O&D businesses. It is our intent to make a public offering of this entity at the appropriate time. Based on the estimated lead time required for such a transaction, and depending on market circumstances, we are aiming to make such an offering in the second half of 2005.

Manufacturing Facilities

BP has large-scale manufacturing facilities in Europe and the USA. The Group s major sites, with our share of their capacities, are: Grangemouth (2,930 ktepa) and Hull (1,595 ktepa) in the UK; Lavéra (1,800 ktepa) in France; Marl (630 ktepa), Gelsenkirchen (1,460 ktepa) and Köln (4,515 ktepa) in Germany; Geel (2,155 ktepa) in Belgium; and Texas City, Texas (2,800 ktepa), Chocolate Bayou, Texas (2,635 ktepa), Decatur, Alabama (2,280 ktepa), and Cooper River, South Carolina (1,330 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 4,450 ktepa, as follows: Indonesia (215 ktepa), South Korea (1,005 ktepa), Malaysia (1,460 ktepa), Taiwan (1,205 ktepa) and China (565 ktepa). When on line in 2005, our share of the complex in Shanghai, planned by SECCO (BP 50%), is expected to add 1,600 ktepa of capacity.

	Years ended December 31,		
Production by region (a)	2003	2002	2001
		(kte)	
UK	3,186	3,221	3,126
Rest of Europe	10,958	10,526	7,925
USA	10,068	10,201	8,943
Rest of World	3,731	3,040	2,722
Total Production (a)	27,943	26,988	22,716

(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.

Table of Contents

OTHER BUSINESSES AND CORPORATE

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

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Turnover	515	510	549
Total operating loss	(904)	(701)	(523)
Total assets	10,231	6,987	7,527
Capital expenditure and acquisitions	409	428	430

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. On January 13, 2004 we sold our investment in PetroChina for $1.65 billion. On February 10, 2004 we sold our investment in Sinopec for $742 million. Separately, BP has formed a joint venture with PetroChina in Guangdong province which had 400 service stations at the end of 2003 and has agreed to form a joint venture with Sinopec to acquire, revamp or build 500 service stations in the Zhehang province. PetroChina and Sinopec are two of China s major companies in the oil and chemicals businesses.

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

Table of Contents

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 2003 was $349 million, compared with $373 million in 2002 and $385 million in 2001.

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, Canada 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 the Environmental Protection section on page 68.

Table of Contents

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 have a material impact on the Group s overall financial position or liquidity. Refer to Item 18 Financial Statements Note 31 on page F-51 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. Fifteen proceedings instituted by governmental authorities are pending or known to be contemplated against BP and certain of its US subsidiaries under US federal, state or local environmental laws, each of which could result in monetary sanctions in excess of $100,000. No individual proceeding is, nor are the proceedings as a group, expected to have a material adverse effect on BP s consolidated financial position or profitability.

Management cannot predict future developments, such as increasingly strict requirements of environmental laws and 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 and Prospects Environmental Expenditure on page 90.

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 reviewing impacts of health safety and environment regulations and obligations related to our 50% ownership of TNK-BP. This document focuses primarily on the US and EU, where over 80% of our fixed assets are located, and on two issues of a global nature: climate change programmes and maritime oil spills regulations.

Table of Contents

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. Before it can be implemented, the Kyoto protocol to the UNFCCC needs to be ratified by at least 55 nations, representing a minimum of 55% of global anthropogenic greenhouse gas (GHG) emissions. The US has indicated that it will not ratify. Therefore, in order for the treaty to come into force, Russia needs to ratify, in addition to those nations which have either already ratified or indicated that they will ratify. If the Kyoto treaty does enter into force and its targets are to be met, some reduction in the use of fossil fuels would be required within countries which have ratified the Kyoto treaty. The impact of the Kyoto agreements on global energy (and fossil fuel) demand is expected to be small (see International Energy Agency Global Energy Outlook, 2000 Edition).

Since 1997, BP has been actively involved in policy debate, worked with others on mitigating technologies, demonstrated global emissions trading and reduced the emissions from our facilities. In early 2002, we announced that we had succeeded in reducing our direct, equity share, GHG emissions by 10% and set a target to maintain our net emissions at 2001 levels through the next decade, with success being dependent upon the resolution of the various international policy discussions on market mechanisms.

BP is an advocate of market mechanisms to allow optimum utilization of resources to meet national Kyoto targets. Such systems 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, and are already implementing national legislation, such as the UK Climate Change Levy.

United Kingdom Emissions Trading Scheme (UKETS)

The UKETS is a voluntary scheme with the UK Government. The Direct Participant section of the scheme provides a financial incentive for organizations that agreed to take on absolute greenhouse gas emissions reduction targets against a 1998-2000 emissions baseline. At present the market is small and any risk from BP s participation in the scheme is low.

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. Once implemented by member states, they will set limits on CO_2 emissions from qualifying installations and issue a finite number of tradable allowances. Under the Directive each installation will also require a GHG emissions permit, which carries an obligation to report, monitor and verify annual emissions and surrender enough allowances to cover these. Most major BP facilities within Europe will be included in the Directive. BP is currently assessing the likely impact on our business, although we expect this to be small, as we are well prepared following the operation of our own internal emissions trading system from 1999-2001, and in the UK from participation in the UKETS.

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 regional review below. 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 2003 our international fleet numbered 28 oil tankers with an average age of three years (25 are double-hulled, three are double-sided) and eight LNG ships with an average age of six years. Our fleet renewal programme will continue into the future and should see 11 modern double-hulled vessels delivered by the end of 2004, with a further 18 confirmed for 2005 to 2007. 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 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. For example, in 1999 BP introduced a premium grade gasoline in Atlanta, Georgia, meeting stringent future sulphur standards and has expanded this offer in over 40 cities across the US. Beginning January 2006, all gasoline produced by BP will have to meet 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).

In 2001, BP entered into a consent decree with the Environmental Protection Agency (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. This settlement requires the installation of additional controls at all of BP s US refineries at a cost currently estimated at $400 million, over at least an eight-year period, and the one-time payment of a $10 million penalty which was made in 2001.

In 2003 the South Coast Air Quality Management District filed a complaint against BP West Coast Products LLC and Atlantic Richfield Company in Los Angeles County Superior Court, alleging multiple violations of air quality regulations at the Carson oil refinery in California, USA. Atlantic Richfield Company operated the refinery until it was transferred to BP West Coast Products LLC on January 1, 2002. The complaint seeks penalties for non-compliance now amounting to $415 million. BP believes

Table of Contents

that it has valid defenses to many of the allegations of the complaint, believes that the amount of the penalty sought is disproportionate to any resulting environmental harm and intends to defend the action vigorously.

BP continues 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. BP has met the requirement to spend at least $15 million on the programme.

The Clean Water Act is designed to protect and enhance the quality of US surface waters by regulating the discharge of wastewater and other pollutants 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.

In 1995, a final federal rule was issued regarding protection of the Great Lakes watershed which has had ongoing impacts on water protection requirements. In 2000, a final federal rule was issued regarding use of Total Maximum Daily Load (TMDL) assessments to address pollutants not meeting water quality standards. EPA deferred implementation of the rule to April 2003 and subsequently withdrew the rule in March 2003, which had the effect of requiring more stringent permit limits at affected industrial facilities. In 2003, EPA published a final strategy for water quality standards and criteria. The strategy lays out actions over the next six years to address a broad range of issues with implications for industrial facilities; these include water use designations, antidegradation, TMDLs, mixing zones, water quality protection criteria and contaminated sediments.

In 2003, BP paid approximately $5.6 million in fines and penalties in the US, about half of which was paid for allegations related to underground storage tanks at its retail operations.

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 fundings 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 for the construction of four double-hull tankers at a shipyard in San Diego, California. The first of these new vessels is expected to begin service in 2004, demise chartered to and operated by Alaska Tanker Company (ATC). The current ATC fleet consists of nine tankers: two with single hulls, four with double bottoms and three 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 240 trained emergency responders at company locations throughout North America. The BART is ready to assist in a response to a major incident.

The Resource Conservation and Recovery Act (RCRA) regulates the storage, handling, treatment, transportation and disposal of hazardous and non-hazardous wastes. It also requires the investigation and remediation of certain locations at a facility where such wastes have been handled, released or disposed of. 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.

71

Table of Contents

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 74 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 State of Montana has pursued claims against Atlantic Richfield Company alleging natural resource damages arising out of Atlantic Richfield Company s predecessors mining and mineral processing activities. In addition, a tribe was allowed to intervene in the lawsuit, Montana vs. Atlantic Richfield Company. These matters were settled in part in 1999, except for the State s claims for $206 million for restoration damages at several sites. In 1989, the EPA filed a CERCLA cost recovery action against Atlantic Richfield Company for oversight costs at several of the Upper Clark Fork River Basin Superfund sites, US vs. Atlantic Richfield Company. Litigation is proceeding on both the EPA s claim, and on Atlantic Richfield Company s counterclaims against various federal agencies seeking contribution from the federal agencies for remediation costs and for any natural resource damage liability it might incur in Montana vs. Atlantic Richfield Company. The settlements in Montana vs. Atlantic Richfield Company, and subsequent settlements resolved the claims and counterclaims in US vs. Atlantic Richfield Company pertaining to four sites and may provide a framework for possible future settlement of the remaining claims. The Group is also subject to other claims for natural resource damage (NRD) under several federal and state laws. This is a developing area under US law which could impact the cost of some cleanups. NRD claims have been asserted by government trustees against several refineries and other company operations.

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 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 Marine Transportation Security Act and Department of Transport Hazmat security compliance regulations in the United States. These regulations require many of our US businesses to conduct Security Vulnerability Assessments, which include requirements such as preparation of security mitigation plans, implementation of upgrades to security measures, appointment and training of a designated security person and submission of plans for approval and inspection.

See also Item 8 Financial Information Legal Proceedings on page 158.

European Union Regional Review

Within the European Union, member states enact regulations to meet the Directives of the European Commission. 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 licenced by July 2005. All plants must be permitted according to 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 2004.

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, limit values for sulphur dioxide, oxides of nitrogen, particulate matter, lead, carbon monoxide, benzene and ozone. A fourth daughter Directive may be agreed in 2004 addressing cadmium, nickel, arsenic and polycyclic aromatic 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.

BP continues to make investments in respect of cleaner fuels at its refineries worldwide. For our European refineries, these investments are important because availability of cleaner fuels is a part of the EU strategy to combat air pollution. In April 1999, the EU adopted a Directive to further reduce the sulphur content of liquid fuels, but excluding marine bunker fuel oil, and marine gas oil used by ships crossing a frontier between a third country and an EU Member State. Sulphur in gas oil is limited to 0.2% from July 2000 and 0.1% from January 2008. From January 2003, sulphur in heavy fuel oil is limited to 1%, except where use of heavy fuel oil up to 3% sulphur can be used in combustion plants without exceeding specific emission limits, and provided that local air quality standards are met.

The EU has set stringent objectives to control exhaust emissions from vehicles, which are being implemented in stages. In 1998, the EU adopted directives to set emission limits for cars and light vehicles to apply from 2000, together with specifications for gasoline and diesel fuel to apply from that date. In 1999, this was followed by emission limits for heavy commercial vehicles. 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.

In Europe there is no overall soil protection regulation, although a draft Directive is expected in 2004. 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. Much of the technical guidance supporting these regulations is in draft form.

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 Authorisation of Chemicals. This proposal will now be discussed by the European Parliament and Council. Dependent on the discussions, entry in force of the regulation could happen by 2007. Although polymers have been temporarily exempted from the process under the current proposal, about 30,000 other chemicals will have to be re-registered and evaluated. For the Group, this will primarily affect petrochemicals, lubricants and refinery products. At present we do not believe this regulation will have a material impact on our business based on the Group s current range of products, although it will require significant management and administration.

The European Commission issued a proposed Directive on Environmental Liability on January 23, 2003, which is currently under consideration within the European Parliament and Council. The proposal seeks to implement a strict liability approach for damage to biodiversity from high-risk operations.

The Commission s Clean Air for Europe Programme aims to conduct a review of the health and environmental effects of air pollution and predicted European Air Quality up to 2020. It will also examine cost-effective solutions to any residual air pollution problems, firstly in a strategy document (expected in 2005) and secondly in legislative proposals (expected between 2005 and 2007) which may include revisions to current regulations on air quality limit values, fuel quality standards, plant emission standards and totally new regulations. BP through various industry bodies is among the various stakeholders contributing to the scientific activities underpinning this work.

Other environment-related existing regulations 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; 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.

Table of Contents

PROPERTY, PLANTS AND EQUIPMENT

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

Table of Contents

ORGANIZATIONAL STRUCTURE

The significant subsidiary undertakings of the Group at December 31, 2003 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-77 and Note 45 on page F-80 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
Europe			
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
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
Netherlands			
BP Capital	100	Netherlands	Finance
BP Nederland	100	Netherlands	Refining and marketing
Norway			
BP Norge	100	Norway	Exploration and production
Spain			
BP España	100	Spain	Refining and marketing
Middle East			
BP Egypt Co.	100	US	Exploration and production
BP Egypt Gas Co.	100	US	Exploration and production
Far East			
Indonesia			
BP Kangean	100	US	Exploration and production
Singapore			
BP Singapore Pte*	100	Singapore	Refining and marketing
Africa			
BP Southern Africa	75	South Africa	Refining and marketing

Table of Contents

Subsidiary undertakings	%	Country of incorporation	Principal activities
Australasia			
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
New Zealand			
BP Oil New Zealand	100	New Zealand	Marketing
Western Hemisphere			
Canada			
BP Canada Energy	100	Canada	Exploration and production
BP Canada Finance	100	Canada	Finance
Trinidad			
BP Trinidad (LNG)	100	Netherlands	Exploration and production
BP Trinidad and Tobago	70	US	Exploration and production
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)	
Standard Oil Co.	100	US)	
BP Capital Markets America	100	US	Finance

77

Table of Contents

ITEM 5 OPERATING AND FINANCIAL REVIEW AND PROSPECTS

GROUP OPERATING RESULTS

	Years ended December 31,		
	2003	2002	2001
	($ million except per share amounts)		
Turnover	232,571	178,721	174,218
Profit for the year	10,267	6,845	6,556
Exceptional items, net of tax	(708)	(1,043)	(165)
Profit before exceptional items	9,559	5,802	6,391
Profit for the year per ordinary share (cents)	46.30	30.55	29.21
Dividends per ordinary share (cents)	26.00	24.00	22.00

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 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. The global economy is expected to strengthen further in 2004.

Average crude oil prices in 2003 were the highest for 20 years, 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 million british thermal unit (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.

The trading environment was generally favourable in the first half of 2001. Natural gas and oil prices remained high until clear evidence of the global economic slowdown emerged after the first few months. Business conditions deteriorated in the second half and remained weak following the events of September 11. Oil prices were 15% down against the levels seen in 2000; refining margins were weak; retailing was fiercely competitive; and in the chemicals sector, margins were at levels below those seen at the bottom of the previous business cycle.

Hydrocarbon production increased by 2.5% in 2003, reflecting an increase of 5.1% for liquids and a decrease of 1.1% for natural gas. The increase was 2.9% in 2002 against a target of 5.5%, reflecting production growth of 4.5% for crude oil and 0.9% for natural gas.

The increase in turnover for 2003 principally includes approximately $44 billion from higher oil, gas and product prices, approximately $10 billion from higher sales volumes and approximately $8 billion from the effect of the weaker US dollar.

The increase in turnover for 2002 reflects approximately $14 billion from production and sales volume increases partly offset by a decrease of approximately $10 billion due to lower natural gas prices.

Profit for 2003 was $10,267 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. 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 results for 2003 include:

- in Exploration and Production, impairment charges and asset writedowns of $691 million and restructuring charges of $117 million;

- in Refining and Marketing, Veba integration costs of $287 million, a $246 million charge resulting from a reassessment of our environmental remediation provisions, charges of $123 million in respect of new environmental remediation provisions and a credit of $10 million arising from the reversal of restructuring provisions;

- in Petrochemicals, a $43 million charge comprising a provision to cover future rental payments on surplus property and a charge resulting from a reassessment of environmental remediation 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 $132 million in respect of new environmental remediation provisions, a provision of $74 million to cover future rental payments on surplus property and a credit of $10 million resulting from a reassessment of our environmental remediation provisions;

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

Refer to Environmental Expenditure on page 90 for more information on environmental remediation charges.

Profit for 2002 was $6,845 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 results for 2002 include:

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;

Table of Contents

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

in Refining and Marketing, impairment costs of $30 million in Gas, Power and Renewables; 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 Other businesses and corporate, a $140 million charge for future rental payments on surplus property and a $46 million charge related to environmental remediation liabilities;

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

For 2001, profit was $6,556 million after inventory holding losses of $1,900 million and including net exceptional gains after tax of $165 million in respect of net profits on the sale of fixed assets and businesses or termination of operations. The results for 2001 include

in Exploration and Production, impairment charges of $175 million, $77 million additional severance costs in respect of Atlantic Richfield Company terminations, $60 million litigation and $10 million restructuring costs;

in Refining and Marketing, integration and rationalization costs of $435 million and $52 million additional severance charges mainly related to former employees of Atlantic Richfield Company;

in Petrochemicals, charges of $114 million related to Grangemouth restructuring and Solvay and Erdölchemie integration;

in Other businesses and corporate, $73 million restructuring charges.

When used in this section, the word result refers to total operating profit.

The increase in the 2003 result compared with 2002 primarily reflects higher oil and gas prices, higher refining and marketing margins and higher production. The reduction in the 2002 result compared with 2001 reflects the challenging environment, although the impact of lower natural gas prices and refining margins was partly offset by higher production and sales volumes, lower costs in certain businesses, improved Petrochemicals performance and contributions from Veba and other acquisitions. 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 chemicals 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, with 20% 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 16% from reorganization of Refining and Marketing operations in Germany. The increase in 2002 was mainly due to the Veba acquisition.

Table of Contents

Return on average capital employed (ROACE) is the ratio of profit including minority shareholders interest and excluding post-tax interest on finance debt to average capital employed for the period. Capital employed is defined as net assets plus total finance debt. Management believes this performance measure is useful as an indication of capital productivity over the long term. The increase in ROACE for 2003 compared with the prior year is due to higher profits. ROACE for 2002 is flat compared with the prior year. Increases in average capital employed are mainly due to acquisitions and upstream investment.

	Years ended December 31,		
Return on average capital employed (ROACE)	2003	2002	2001
		($ million)	
Profit for the year	10,267	6,845	6,556
Interest on finance debt (a)	332	602	798
Minority shareholders interest	170	77	61
	10,769	7,524	7,415
Average capital employed	95,722	89,616	87,259
ROACE	11%	8%	8%

(a) For the ROACE calculation, interest expense includes interest on finance debt on a post-tax basis, using a deemed tax rate equal to the US statutory tax rate.

	Years ended December 31,		
Capital expenditure and acquisitions	2003	2002	2001
		($ million)	
Exploration and Production	9,658	9,266	8,627
Gas, Power and Renewables	359	335	485
Refining and Marketing	3,006	2,682	2,386
Petrochemicals	775	810	1,446
Other businesses and corporate	251	228	256
Capital expenditure	14,049	13,321	13,200
Acquisitions (a)	6,026	5,790	924
Capital expenditure and acquisitions	20,075	19,111	14,124
Disposals	(6,432)	(6,782)	(2,903)
Net Investment	13,643	12,329	11,221

(a) 2003 includes $5,794 million for the acquisition of our interest in TNK-BP. 2002 includes $5,038 million for the Veba acquisition.

Capital expenditure and acquisitions in 2003, 2002 and 2001 amounted to $20,075 million, $19,111 million and $14,124 million, respectively. Acquisitions in 2003 included our interest in TNK-BP. Acquisitions during 2002 included Veba, an additional 15% interest in Sidanco and several minor acquisitions. Acquisitions during 2001 included the purchase of Bayer s 50% interest in Erdölchemie and a number of minor acquisitions. Excluding acquisitions, capital expenditure for 2003 was $14,049 million compared with $13,321 million in 2002 and $13,200 million in 2001.

Exceptional Items

For 2003, net exceptional gains, consisting of the profit or loss on sale of fixed assets and businesses or termination of operations, were $831 million before tax ($708 million after tax). 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.

Net exceptional gains were $1,168 million before tax ($1,043 million after tax) in 2002. 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.

For 2001, net exceptional gains were $535 million before tax ($165 million after tax). The profit on the sale of fixed assets of $948 million includes the profit from the divestment of the refineries at Mandan, North Dakota, and Salt Lake City, Utah; the Group s interest in the Alliance and certain other pipeline systems in the USA; and BP s interest in the Kashagan discovery in Kazakhstan. The profit on the sale of businesses of $182 million relates to the sale of the Group s interest in Vysis. In 2001, the loss on sale of fixed assets of $345 million arose from a number of transactions. The loss on sale of businesses and termination of operations of $250 million during 2001 arose principally from the sale of the Group s Carbon Fibers business and the write-off of assets following the closure or exit from certain chemicals activities.

Interest Expense

Interest expense in 2003 was $851 million compared with $1,279 million in 2002 and $1,670 million in 2001. These amounts included charges arising from early bond redemption of $31 million, $15 million and $62 million respectively. After adjusting for these charges, the decrease in Group interest expense in 2003 compared with 2002 mainly reflects lower average interest rates and lower average debt. The decrease in 2002 compared with 2001 primarily reflects lower average interest rates.

Taxation

The charge for corporate taxes in 2003 was $5,972 million, compared with $4,342 million in 2002 and $6,375 million in 2001. The effective rate was 36% in 2003, 39% in 2002 and 49% in 2001. The lower rate in 2003 reflects tax restructuring benefits, as well as the rateably lower impact of goodwill amortisation and the depreciation charge 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. The lower rate in 2002 reflects non-taxable inventory holding gains compared with inventory holding losses in 2001.

Table of Contents

Business Operating Results

Total operating profit, which is before interest expense, taxation, minority interests and exceptional items, was $16,429 million in 2003, $11,375 million in 2002 and $14,127 million in 2001.

Exploration and Production

		Years ended December 31,		
		2003	2002	2001
Turnover	($ million)	31,341	25,753	28,229
Profit before interest and tax	($ million)	14,853	8,483	12,550
Exceptional (gains) losses	($ million)	(913)	726	(195)
Total operating profit	($ million)	13,940	9,209	12,355
Results included:				
Exploration expense	($ million)	542	644	480
Key statistics:				
Average BP crude oil realizations (a)	($ per barrel)	28.23	24.06	23.27
Average BP NGL realizations (a)	($ per barrel)	19.26	12.85	16.27
Average BP liquids realizations (a) (b)	($ per barrel)	27.25	22.69	22.50
Average West Texas Intermediate oil price	($ per barrel)	31.06	26.14	25.89
Average Brent oil price	($ per barrel)	28.83	25.03	24.44
Average BP US natural gas realizations (a)	($ per thousand cubic feet)	4.47	2.63	3.99
Average Henry Hub gas price (c)	($ per thousand cubic feet)	5.37	3.22	4.26
Crude oil production (net of royalties) (d)	(mb/d)	2,121	2,018	1,931
Natural gas production (net of royalties) (d)	(mmcf/d)	8,613	8,707	8,632
Total production (net of royalties) (d) (e)	(mboe/d)	3,606	3,519	3,419

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

(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 2003 was $31,341 million compared with $25,753 million in 2002 and $28,229 million in 2001. The increase in 2003 reflected the impact of higher liquids and natural gas realizations of approximately $7.0 billion with an offset of $1.4 billion as a result of a decrease in production volumes in the USA and UK following divestments. The decrease in 2002 included approximately $2.3 billion due to lower natural gas prices with a small offset of $100 million as a result of higher production and crude oil realizations.

Total hydrocarbon production for 2003 was 3,606 mboe/d, an increase of 2.5% compared with 2002. This includes the 135 mboe/d impact of divestments offset by the inclusion of 205 mboe/d TNK-BP volumes incremental to Sidanco, from August 29, 2003.

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

Table of Contents

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. Profit before interest and tax in 2001 includes net exceptional gains of $195 million, which includes a gain on the sale of our interest in the Kashagan discovery in Kazakhstan together with net losses on the sale of various other upstream interests.

Total operating profit for 2003 was $13,940 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 Kepadong 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. All of these fields continue in operation. Additionally, there were restructuring charges of $117 million in respect of ongoing restructuring activities in the UK and North America.

For 2003, the year on year increase in operating profit reflects higher natural gas realizations partly offset by higher costs and other factors. Higher natural gas realizations contributed $5.4 billion 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. The annual impact in 2003 of the removal of the unrealized profit in inventory in the Exploration and Production business for product held by other areas of the Group s business was a charge of $61 million compared with a charge of $154 million in 2002.

Finding and development costs in 2003 averaged $6.49 per barrel of oil equivalent (boe), compared with $4.14 in 2002 and $3.68 in 2001. Finding and development costs are those costs incurred during the year on exploration activity (exploration drilling, licence awards, exploration geological and geophysical expense) and costs incurred in the development of our tangible fixed assets, excluding midstream activities. In the determination of finding and development costs per barrel, the summation of these costs is divided by reserves either added, or removed, by revisions, discoveries, extensions and improved recovery. The denominator excludes volumes associated with purchases and sales. The increase reflects the focus on our new profit centres and the build phase of our major projects. Finding costs were $0.73/boe, compared with $0.79 in 2002 and $0.54 in 2001. Finding costs are based on exploration costs incurred per barrel of oil equivalent added as a result of extensions and discoveries. On a three year rolling average basis, the finding costs were $0.66/boe for 2003 compared with $0.78 for 2002 and $0.82 for 2001 reflecting the significant discoveries made during the period 2000 to 2002. BP has discovered more giant fields (greater than 250 mmboe) in the period 1998 2003 than our competitors. Unit lifting costs (i.e., production costs per unit) were $2.80/boe (compared with $2.60 in 2002 and $2.70 in 2001). Adjusting for the impact of foreign exchange from our non-US dollar denominated business activities, which has had a more significant impact in 2003 as a result of the weakening of the US dollar, would give $2.70/boe in 2003. This reflects our continued focus on controlling cash costs. Unit lifting costs are based on total production costs divided by the production from those entities whose costs are consolidated. Production costs include expenditure incurred in lifting, gathering and treating, field processing and other directly related facilities, but exclude production-related depreciation.

Table of Contents

Total operating profit for 2002 was $9,209 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 evaluations 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 decrease in the 2002 result compared with 2001 was primarily as a result of significantly lower natural gas realizations, accounting for approximately $2.3 billion of the reduction. This was offset slightly by the impact of higher crude oil realizations of $110 million, production growth of 4.5% for crude oil and 0.9% for natural gas (2.9% overall) which generated $360 million and a 4% decrease in unit lifting costs and other costs amounting to approximately $540 million. Other factors which impacted the results were an increase in exploration expense of $164 million, the impact of prices on the provision for unrealized profit in inventory of $322 million and increases in depreciation, depletion and amortization (including impairments).

Total operating profit for 2001 was $12,355 million after inventory holding losses of $6 million. The result for 2001 includes a $175 million impairment of our partner-operated Venezuelan Lake Maracaibo operations, following a technical reassessment, $77 million additional severance costs which related to US pension and benefits incurred in respect of terminations by Atlantic Richfield Company and were settled in 2001, $60 million litigation and $10 million restructuring costs related to the Grangemouth operating site in Scotland.

Total hydrocarbon production for 2002 was 3,519 mboe/d, an increase of 2.9% compared with 2001. This reflects a 252 mboe/d impact of production from new fields and acquisitions partly offset by: 53 mboe/d from operational problems mainly in the UK and Alaska; 25 mboe/d from OPEC reductions and lower natural gas demand as a result of warm weather, 20 mboe/d from severe storm patterns in the Gulf of Mexico and 4 mboe/d from the general strike in Venezuela.

Gas, Power and Renewables

		Years ended December 31,		
		2003	2002	2001
Turnover	($ million)	65,445	37,357	39,442
Profit before interest and tax	($ million)	472	1,956	407
Exceptional (gains) losses	($ million)	6	(1,551)	
Total operating profit	($ million)	478	405	407
Total natural gas sales volumes (a)	(mmcf/d)	26,269	21,621	18,794

(a) Includes marketing, trading and supply sales.

Turnover was $65,445 million in 2003 compared with $37,357 million in 2002, reflecting $20 billion additional turnover from higher natural gas prices and approximately $8 billion from higher gas sales volumes. The decrease in 2002 from $39,442 million in 2001 reflected a decrease of approximately $9 billion due to lower prices, particularly in North America, partly offset by an increase of approximately $7 billion from higher natural gas sales volumes.

Table of Contents

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 Rurhrgas. Profit before interest and tax for 2001 includes no exceptional gains or losses.

Total operating profit for 2003 was $478 million including inventory holding gains of $6 million.

Total operating profit for 2002 was $405 million including inventory holding gains of $51 million. The result for 2002 includes 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.

Total operating profit for 2001 was $407 million after inventory holding losses of $81 million.

The increase in the result 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.

The decrease in the result in 2002 compared with 2001 is due to a $75 million lower contribution from Ruhrgas (shareholding held for 7 months prior to disposal) and a decline of $80 million from a weaker marketing and trading environment, partly offset by better performance in the NGL business of $10 million and $50 million from increased natural gas sales volumes which were up by 15%.

Refining and Marketing

		Years ended December 31,		
		2003	2002	2001 (a)
Turnover	($ million)	149,477	125,836	120,233
Profit before interest and tax	($ million)	2,079	2,534	2,461
Exceptional (gains) losses	($ million)	213	(613)	(471)
Total operating profit	($ million)	2,292	1,921	1,990
Global Indicator Refining Margin (a)	($/bbl)	3.88	2.11	4.06
Refining availability (b)	(%)	95.5	96.1	95.4
Refinery throughputs	(mb/d)	3,097	3,103	2,929
Total marketing sales	(mb/d)	4,032	4,180	3,797

(a) 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 measures rather than BP specific, 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.

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

Turnover for 2003 was $149,477 million compared with $125,836 million for 2002 and $120,233 million for 2001. Higher oil prices contributed approximately $14 billion of the increase in 2003, with foreign exchange movements and higher volumes (including trading and supply sales) contributing a further $8 billion and $3 billion respectively. The increase in turnover for 2002 compared with 2001 is due primarily to volume increases from the Veba acquisition. Results for Veba have been included from February 1, 2002.

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. Profit before interest and tax for 2001 includes net exceptional gains of $471 million, which includes a gain from the sale of the refineries at Mandan, North Dakota and Salt Lake City, Utah, a gain from the the sale of Group s interests in Alliance and certain other pipelines in the US and net losses from other items.

Total operating profit for 2003 was $2,292 million after inventory holding losses of $48 million. The result for 2003 includes Veba integration costs of $287 million, a $246 million charge resulting from a reassessment of our environmental remediation provisions, charges of $123 million in respect of new environmental remediation provisions following a detailed review earlier in the year and a credit of $10 million arising from the reversal of restructuring 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 2002 was $1,921 million including inventory holding gains of $1,049 million. The result for 2002 includes 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.

Total operating profit for 2001 was $1,990 million after inventory holding losses of $1,583 million. The result for 2001 includes Burmah Castrol integration costs of $334 million, charges of $101 million related to rationalization costs in the downstream European commercial business and Grangemouth restructuring and $52 million additional severance charges mainly related to former employees of Atlantic Richfield Company.

The result 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, additional portfolio impacts of around $150 million and additional pension charges of approximately $200 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, as expected, due to divestments.

The result for 2002 compared with 2001 reflects the impact of a decline of worldwide refining margins, down by around $2,400 million, lower marketing margins of around $400 million, additional environmental provisions of $150 million and increased pension charges of $100 million. The decrease was partly offset by the net impact of portfolio activity, including the Veba transaction, of approximately $400 million. Refining throughputs increased by 6% over the prior year and marketing volumes increased by 10%, primarily due to Veba. Excluding Veba, marketing volumes were slightly down. Retail shop sales grew 60% due to Veba and the increased number of BP Connect stations, 10% excluding Veba. Retail sales grew 7% in 2002 in stores that were also operating in 2001.

Table of Contents

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 special charges were approximately $260 million. Annual synergies of approximately $300 million have so far been delivered, in excess of the $200 million previously anticipated.

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 special charges were approximately $140 million. The $132 million special 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.

The integration of the Atlantic Richfield Company businesses was largely completed during 2001 and primarily affected the Western USA. The anticipated downstream synergies were achieved, resulting from cost reduction, hydrocarbon procurement and working capital reduction. The charges associated with the integration were $52 million in 2001. The major components of the costs were severance payments, office consolidation and information technology infrastructure.

The integration of the Burmah Castrol businesses was mostly completed by the end of 2001. The anticipated synergies of $260 million per year, resulting from efficiencies in supply chain and support activities, were exceeded by $20 million and delivered one year in advance. The costs associated with restructuring, integration and rationalization were $485 million ($334 million in 2001 and $151 million in 2000). The majority of the costs were related to severance payments, relocation and infrastructure.

Petrochemicals

		Years ended December 31,		
		2003	2002	2001
Turnover	($ million)	16,075	13,064	11,515
Profit before interest and tax	($ million)	661	285	(399)
Exceptional (gains) losses	($ million)	(38)	256	297
Total operating profit	($ million)	623	541	(102)
Chemicals Indicator Margin (a)	($/te)	112	104	109
Production volumes (b)	(kte)	27,943	26,988	22,716

(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, linear alpha-olefins (LAOs), acetic acid, vinyl acetate monomers and nitriles. Not included are fabrics and fibres, plastic fabrications, poly alpha-olefins (PAOs), anhydrides, engineering polymers and carbon fibres, speciality intermediates and the remaining parts of the solvents and acetyls businesses. This measure is not BP specific, rather it is an indicator of relative industry profitability and BP s actual margins will differ. While not entirely representative of BP s complete range of products, we believe it does provide investors with useful information about the environment for BP s products.

Table of Contents

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

Turnover has increased from $11,515 million in 2001 to $13,064 million in 2002 and to $16,075 million in 2003. The increase in turnover for 2003 compared with 2002 primarily reflects higher sales prices. The increase in turnover for 2002 compared with 2001 primarily reflects higher production as a result of acquisitions, organic growth and improved site reliability.

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. Profit before interest and tax for 2001 includes net exceptional losses of $297 million, including losses on the sale of termination of a number of petrochemical activities including the Carbon Fibers business.

Total operating profit for 2003 was $623 million including inventory holding gains of $55 million. The result for 2003 includes a $43 million charge comprising a provision to cover future rental payments on surplus property and a charge resulting from a reassessment of our environmental remediation 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 $541 million including inventory holding gains of $26 million. The result for 2002 includes 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.

Total operating loss for 2001 was $102 million after inventory holding losses of $230 million. The result for 2001 includes charges of $114 million related to Grangemouth restructuring and Solvay and Erdölchemie integration.

The 2003 result 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 when compared to 2002.

The 2002 result increased relative to 2001 in an overall trading environment that was similar. Increased production contributed around $500 million of this improvement and $24 million was driven by lower costs.

BP s share of 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. Production for 2002 was 26,988 thousand tonnes, up 19% on 2001 as a result of new production from existing and acquired assets. Production for 2001 was 22,716 million tonnes.

Other Businesses and Corporate

		Years ended December 31,		
		2003	2002	2001
Turnover	($ million)	515	510	549
Loss before interest and tax	($ million)	(805)	(715)	(357)
Exceptional (gains) losses	($ million)	(99)	14	(166)
Total operating loss	($ million)	(904)	(701)	(523)

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

On January 1, 2002, the solar, renewables and alternative fuels activities were transferred to Gas, Power and Renewables. Comparative information has been restated.

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 loss before interest and tax for 2001 includes net exceptional gains of $167 million, which primarily relate to a gain on the disposal of the Group s majority interest in Vysis.

The net cost of Other businesses and corporate amounted to $904 million in 2003, $701 million in 2002 and $523 million in 2001. The net cost for 2003 includes a charge of $132 million in respect of new environmental remediation provisions, a provision of $74 million for future rental payments on surplus leasehold property and a credit of $10 million resulting from a reassessment of our environmental remediation provisions. The net cost 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. The net cost for 2001 includes additional severance charges of $73 million mainly related to former employees of Atlantic Richfield Company.

In early 2004, we sold our investment in PetroChina for $1.65 billion and our investment in Sinopec for $0.7 billion.

Environmental Expenditure

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Operating expenditure	498	485	436

Clean-ups	45	49	67
Capital expenditure	546	548	423
New provisions for environmental remediation	515	312	180
New provisions for decommissioning	1,159	308	156

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

Table of Contents

Operating expenditure and clean-ups for 2003 were broadly in line with the 2002 and 2001 levels. Capital expenditure for 2003 was flat compared with 2002. The increase in 2002 compared with 2001 was primarily a result of projects to reduce refinery emissions associated with our agreement with the Environmental Protection Agency and upgrades required to meet new US emission requirements for gasoline and highway diesel. Capital expenditures are expected to be at levels similar to 2003 in the near term. In addition to operating and capital expenditures, we also create provisions for future environmental remediation. The charge for new provisions in 2003 principally includes $236 million resulting from a reassessment of environmental remediation provisions and $255 million in respect of new environmental remediation provisions. The increase in new provisions in 2003 and 2002 is primarily related to US retail sites and results from ongoing review of the liabilities and new regulations. Expenditure against such provisions is normally incurred in subsequent periods and is not included in environmental operating expenditure reported for such periods.

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

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

In addition, we make provisions to meet the cost of eventual decommissioning of our oil- and gas-producing assets and related pipelines. New provisions for decommissioning in 2003 include amounts for certain fields on installation of production facilities and increases in respect of reassessment of existing provisions. 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. During the year, six new fields came on stream and provisions for these were established for the first time. Additionally, we undertake periodic reviews of existing provisions. These reviews take account of revised cost assumptions, changes in decommissioning requirements and any technological developments. The outcome of the periodic reviews conducted during 2003 indicated that an increase in certain provisions was required.

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 31 on page F-51. See also Item 4 Information on the Company Environmental Protection on page 68.

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.

Table of Contents

LIQUIDITY AND CAPITAL RESOURCES

Cash Flow

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Net cash inflow from operating activities	21,698	19,342	22,409
Net cash inflow (outflow)	1,342	(344)	1,002

Net cash inflow for 2003 was $1,342 million, compared with an outflow of $344 million in 2002, as operating cash flow increased $2,356 million and acquisition spending decreased $1,762 million, which was partly offset by an increase in tax payments of $1,710 million, an increase in equity dividends of $390 million and a decrease in disposal proceeds of $350 million. The decrease in net cash flow for 2002 compared with 2001 reflected a decrease in operating cash flow of $3,067 million, an increase in acquisition spending of $3,114 million and $437 million higher equity dividends, partly offset by a $1,566 million decrease in tax payments and $3,879 million higher disposal proceeds.

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 $4,717 million and an increase in the net charge for provisions of $680 million, partly offset by an additional working capital requirement of $3,372 million which included $2,533 million discretionary funding for the Group s pension plans. The decrease in 2002 from $22,409 million in 2001 was due to $2,119 million lower profit and an additional working capital requirement of $2,318 million which were partly offset by a $1,543 million increase in depreciation resulting from impairments.

Dividends from joint ventures and associated undertakings have decreased from $632 million in 2001 to $566 million in 2002 and to $548 million in 2003. The decrease in 2003 compared with 2002 was related to the Ruhrgas and Altura transactions in 2002 partly offset by the contribution from TNK-BP in 2003. The decrease in 2002 compared with 2001 was related to the Erdölchemie transaction and the Altura transaction partly offset by an increase from Watson Cogeneration.

The net cash outflow from servicing of finance and returns from investments was $711 million in 2003, $911 million in 2002 and $948 million in 2001. The lower cash outflow in 2003 and 2002 is primarily due to lower interest payments.

Tax payments increased to $4,804 million in 2003 from $3,094 million in 2002, primarily reflecting the increase in profits for the period. The decrease in 2002 compared with 2001 reflects the decline in profits across the period.

Payments for capital expenditures on fixed assets net of proceeds from sales of fixed assets, amounted to $6,187 million in 2003 compared with $9,646 million in 2002 and $9,849 million in 2001. The decrease in 2003 reflects higher disposal proceeds. The decrease in 2002 over 2001 was due to slightly lower capital expenditure and higher disposal proceeds.

Acquisitions and disposals of businesses produced net cash outflows of $3,548 million in 2003, $1,337 million in 2002 and $1,755 million in 2001. The higher outflow in 2003 reflects lower disposal proceeds. In 2002, the impact of the Veba acquisition was more than offset by higher disposal proceeds.

Overall net cash outflow for capital expenditure and acquisitions, net of disposals, was $9,735 million in 2003 compared with $10,983 million in 2002 and $11,604 million in 2001.

Table of Contents

Dividend payments have increased to $5,654 million in 2003 compared with $5,264 million in 2002 and $4,827 million in 2001. The increase in both years reflects the impact of the higher dividend per share, partly offset by share repurchases.

The Group has had significant levels of investment for many years. Investment, excluding acquisitions, was $14.0 billion in 2003, $13.3 billion in 2002 and $13.2 billion in 2001. 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 very little change in the Group s level of net debt, that is debt less cash and liquid resources; net debt has increased from $19.6 billion at the end of 2001 to $20.3 billion at the end of 2002 and was $20.2 billion at the end of 2003.

Over the period 2000 to 2003 our cash inflows and outflows were balanced, with sources and uses both totalling $92 billion. Since 2000, the year in which we completed the purchase of Atlantic Richfield Company, the price of Brent has averaged $26.7/bbl, somewhat higher than was expected as the period opened. The following table summarizes the four year sources and uses of cash in post-tax terms:

Sources	**$ billion**	**Uses**	**$ billion**
Adjusted operating cash flow(a)	67	Capital Expenditure	52
Divestments	25	Acquisitions	14
		Share buybacks	6
		Dividends	20
	92		92

(a) Refer to page 103 for a definition of adjusted operating cash flow.

Capital expenditure used about 70% of post-tax operating cash flow from 2000 to 2003, a proportion which is significantly higher than for most other major oil companies. 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 by 6.8% per year in dollar terms, used $20 billion. $6 billion was used for share repurchases. Finally, cash was used to strengthen the financial condition of certain of our pension funds.

Future Cash Flows and Capital Expenditure

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 normal funding programme of $400-500 million per year. We have the capacity to adjust this funding should unforeseen circumstances warrant.

Secondly, organic capital expenditure, that is capital expenditure excluding acquisitions, will decline as we pass the peak of the recent investment cycle. This is already happening today, with projected 2004 organic capital expenditure down on 2003 despite some upward pressure from the weaker US dollar.

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.

93

Table of Contents

Our plans for the future level of investment and divestment are shown on the table below:

	Years ended December 31,		
	2003	2004	2005
		($ billion)	
Capital expenditure			
Exploration and Production	9.7	9.0	
Gas Power and Renewables	0.3	0.6	
Refining and Marketing	3.0	2.8	
Petrochemicals	0.8	0.9	
Other	0.2	0.2	
	14.0	13.5	12.0-12.5
Acquisitions	6.0	1.4	
Divestments	(6.4)	(3.0-4.0)	(1.0)

We expect capital expenditure for the Company to decrease to a level of $12 billion to $12.5 billion per year in 2005 and 2006 and divestment to a level of around $1 billion per year (about half the level of the recent past), mostly due to routine portfolio upgrading. These figures exclude the effects of the possible public offering of our Olefins and Derivatives business. The only currently identified acquisition over this period is the purchase of the remainder of Solvay s stake in our high-density polyethylene joint venture, should Solvay decide to exercise their put option to us.

The existing profit centres in our upstream business have proved reserves of 9.3 billion boe, including joint ventures and associates, and in 2003 contributed some 2 million boe/d of production. We estimate the decline in production will be around 3% per year from 2004 to 2008. This is in line with a decline of between 3 and 4% per year on average between 2002 and 2004. However, production from our existing and new upstream profit centres (but excluding Russia), we estimate will grow in aggregate by around 5% per year on average between 2003 and 2008.

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, 2003 amounted to $22,325 million (2002 $22,008 million) of which $9,456 million (2002 $10,086 million) was short term.

Net debt was $20,193 million at the end of 2003, a decrease of $80 million compared with 2002. The ratio of net debt to net debt plus equity was 21% at the end of 2003 and 22% at the end of 2002.

The maturity profile and fixed/floating rate characteristics of the Group s debt are described in Item 18 Financial Statements Notes 26 and 29 on pages F-39 and F-47, respectively.

We have in place a European Debt Issuance Programme (DIP) and a US Shelf Registration under each of which the Group may raise $8 billion and $6 billion of debt respectively for maturities of one month or longer. At June 23, 2004, the amount drawn down against the DIP was $3,476 million, and $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, 2003 the outstanding commercial paper amounted to $4,243 million (2002 $4,853 million).

Table of Contents

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, 2003 the Group s share of third party borrowings of joint ventures and associated undertakings was $2,151 million (2002 $457 million) and $922 million (2002 $849 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, 2003 are summarized below. Some guarantees outstanding are in respect of borrowings of joint ventures and associated undertakings noted above.

	Guarantees expiring by period						
	Total	2004	2005	2006	2007	2008	2009 and thereafter
	($ million)						
Guarantees issued in respect of:							
Borrowings of joint ventures and associated undertakings	635	93	129	29	138	28	218
Liabilities of other third parties	304	115	82	31	8	40	28

At December 31, 2003 contracts had been placed for authorized future capital expenditure estimated at $6,420 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, 2003, the Group had available undrawn committed borrowing facilities of $3,700 million ($3,600 million at December 31, 2002).

Table of Contents

Contractual Commitments

The following table summarizes the Group s principal contractual obligations at December 31, 2003. Further information on borrowings and capital leases is given in Item 18 Financial Statements Note 29 on page F-47 and further information on operating leases is given in Item 18 Financial Statements Note 17 on page F-29.

Expected payments by period under contractual obligations and commercial commitments	Payments due by period						
	Total	2004	2005	2006	2007	2008	2009 and thereafter
				($ million)			
Borrowings (a)	20,143	9,366	2,674	2,786	1,299	945	3,073
Finance lease obligations	4,634	127	243	248	240	248	3,528
Operating leases	8,115	1,275	1,066	895	799	728	3,352
Decommissioning liabilities	7,504	86	156	173	154	156	6,779
Environmental liabilities	2,430	465	441	402	276	186	660
Pensions (b)	26,682	633	649	652	659	666	23,423
Other post-employment benefits (c)	11,768	242	252	259	263	264	10,488
Unconditional purchase obligations (d)	67,828	45,491	7,076	3,133	1,888	1,655	8,585

(a) Expected payments exclude interest payments on borrowings.

(b) Represents the expected future contributions to funded pension plans and payments by 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 2004 include purchase commitments existing at December 31, 2003 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 170.

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

Unconditional purchase obligations payments due by period	Payments due by period						
	Total	2004	2005	2006	2007	2008	2009 and thereafter
				($ million)			
Crude oil and oil products	22,043	19,350	844	452	422	374	601

Natural gas	19,439	13,189	2,575	1,141	489	398	1,647
Chemicals and other refinery feedstocks	10,049	2,277	1,666	753	563	545	4,245
Utilities	11,612	9,622	1,231	289	62	54	354
Transportation	2,814	738	510	365	247	204	750
Use of facilities and services	1,871	315	250	133	105	80	988
Total	67,828	45,491	7,076	3,133	1,888	1,655	8,585

96

Table of Contents

The following table summarises the Group s capital expenditure commitments at December 31, 2003 and the proportion of that expenditure for which contracts have been placed. The Group expects its total capital expenditure excluding acquisitions to be around $13.5 billion in 2004 and to be in the range $12.0 billion to $12.5 billion in 2005.

Capital expenditure commitments including amounts for which contracts have been placed	Total	2004	2005	2006	2007	2008	2009 and thereafter
				($ million)			
Committed on major projects	17,455	8,372	3,536	2,362	1,031	1,087	1,067
Amounts for which contracts have been placed	6,420	4,449	1,185	490	148	91	57

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 from 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 and also has undrawn committed borrowing facilities to meet currently foreseeable borrowing requirements. At December 31, 2003, the Group had available undrawn committed facilities of $3,700 million. These committed facilities, which are mainly with a number of international banks, expire in 2004. The Group expects to renew the facilities on an annual basis.

Credit Risk

Credit risk is the potential exposure of the Group to loss in the event of non-performance by a counterparty. The credit risk arising from the Group s normal commercial operations is controlled by individual operating units within guidelines. In addition, as a result of its use of derivatives to manage market risk, the Group has credit exposures through its dealings in the financial and specialized oil and natural gas markets. The Group controls the related credit risk through credit approvals, limits, use of netting arrangements and monitoring procedures. Counterparty credit validation, independent of the dealers, is undertaken before contractual commitment.

Table of Contents

OUTLOOK

The world economy grew at above the ten-year average in the first quarter of 2004, and appears to have slowed somewhat through the second quarter to a growth rate close to trend. The US and Asian economies, particularly China, remain robust. Europe, with the exception of the UK, continues to lag. For 2004 as a whole, the consensus is for global growth close to trend, with the US and Asia expected to grow at or above trend and mainland Europe expected to remain below trend.

At just over $32 per barrel (dated Brent), crude oil prices during the first quarter were the highest since the fourth quarter of 1990 (immediately prior to the first Gulf War). Prices have averaged around $35.47 so far in the second quarter (through close June 23, 2004). Strong oil demand growth, low inventories, a tight US gasoline market and concern about possible supply disruptions have kept crude oil prices supported, notwithstanding the continuing high levels of OPEC production. OPEC s decision in early June to raise quotas and signs that Saudi Arabia and the U.A.E. are adding around 1 million barrels per day to production this month suggest that the market will be fully supplied as we head into the second half of the year.

US natural gas prices traded in a relatively narrow range for most of the first quarter, averaging $5.69/mmbtu (Henry Hub first of the month index). The index has been even higher in the second quarter, at $6.00/mmbtu, reflecting the exceptional strength of oil prices. Spot gas prices have traded between residual fuel oil and distillate parity for most of the last year. Working gas in storage currently stands well above last year s levels and very close to the five-year (1999-2003) average. With storage at adequate levels and with growth in supply and demand looking more balanced than in recent years, we expect that gas prices will remain strongly influenced by movements in oil prices for the remainder of 2004. Summer temperatures will also be an important determinant of third quarter prices.

Refining margins in the first quarter strengthened relative to the fourth quarter 2003 in the face of declining product inventories, strong global oil demand growth and cold US weather. Margin gains were most pronounced in the US, where low gasoline inventories and specification changes raised concerns about supply during this year s driving season. During the second quarter, refining margins reached record highs as strong US gasoline demand growth prevented inventories from building despite a partial recovery in import volumes. Meanwhile, global marketing unit margins have continued to be under pressure due to the further rise in crude price and product costs, though have recently shown some recovery.

Petrochemical margins in the first half of 2004 improved compared to the previous six months but were still under pressure from the high cost of feedstocks. This pressure is expected to continue for the balance of the year. We continue to remain cautious regarding the overall petrochemicals market although we expect sales in 2004 to be higher compared to last year provided the global economic recovery is sustained.

Table of Contents

PROSPECTS

Set forth below under the heading Business Strategy and Prospects are statements regarding the strategy and prospects of the Group. Terms used in these statements and not defined elsewhere in this Form 20-F are defined below. These statements also include references to non-GAAP financial measures. Under Defined Terms and Non-GAAP Financial Measures below, we identify and define these measures, provide the nearest equivalent GAAP financial measures and explain why Management believes these measures provide investors with useful information.

Under the heading Reconciliation of Non-GAAP Financial Measures on pages 115 to 119 below we include a quantitative reconciliation of the historical non-GAAP financial measures to the nearest equivalent GAAP financial measures. We also refer to forward-looking non-GAAP financial measures for which at this time there are no comparable GAAP measures and which at this time cannot be quantitatively reconciled to comparable GAAP measures.

The discussion below contains forward-looking statements with respect to the plans and prospects of the Group, future capital expenditure, forward-looking rules of thumb, future hydrocarbon production volume, date or period(s) in which production is scheduled or expected to come on stream, changes to BP s financial reporting due to the adoption of FRS 17, operating capital employed/capital in service, cash returns, underlying cash flows, finding and development costs, BP s intentions with respect to shareholder distributions and share buybacks, gearing, opportunities for material acquisitions and costs for providing pension and other postretirement benefits. 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 Forward-Looking Statements on page 12 and Risk Factors on pages 10 and 11 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 forward-looking statements or to publish financial projections or forward-looking statements in the future.

All forward-looking non-GAAP information has been calculated at plan conditions, i.e., based on assumed prices of $20 per barrel Brent, $3.50 per mmbtu Henry Hub natural gas and a global refining indicator margin of $2.70 per barrel. Comparative non-GAAP financial information for 2003 and prior years has been adjusted based on the same planning assumptions used for the forward-looking information.

References to production and proved reserves in the comments below represent the sum of the production and reserves of subsidiaries and equity-accounted entities. BP does not control the production or reserves of equity-accounted entities.

When we discuss production, we mean a number, usually in barrels of oil equivalent, which is an indicator of the trend of average daily output of hydrocarbons. It is not an amount which can be targeted, nor is it a specific forecast for a year. The indicator does not include any provision for downtime above the average observed over the last five years, the effect of prices above $20 per barrel Brent on entitlement volumes from PSAs, the effect of weather patterns outside of the normal trend, as well as other items noted in the cautionary statement. We have come to the view that defining production in this way is more useful than an indicator of capacity, which is a concept with an unhelpfully wide range of interpretations.

When we talk about growth rates in production, these are calculated as cumulative average growth rates over a period. They are not therefore growth rates that might be observed year after year.

Table of Contents

2004 Reporting Changes

The changes we have made for 2004 reporting are summarized below.

In 2004 we are:

- adjusting our accounting for employee share ownership plans as required by a new UK law;
- transferring certain NGL operations from the Exploration and Production segment to the Gas, Power and Renewables segment;
- adopting Financial Reporting Standard No. 17 (FRS 17), the new UK GAAP pension and benefit reporting standard;
- moving to what has become the industry norm of not adjusting headline earnings for exceptional items and those items previously designated as special items, though we will continue to identify those non-operating items which have a material impact on our results;

We have restated the historical results for these changes, and this is the basis for the discussion of BP s strategy below. The effects of the first three changes set out above on our historical financial information are quantified under the heading The Effect of Accounting Changes in 2004 on Prior Period Financial Information on page 111.

Rules of Thumb: 2004 Operating Environment

We believe that investors may find it useful to apply the following forward-looking rules of thumb to estimate the impact of changes in the trading environment on BP s 2004 pre-tax earnings. These rules of thumb are approximate. We consider rules of thumb more useful on an annual basis than for quarter-to-quarter comparisons, as annual comparisons tend to smooth out much of the volatility in differentials, working capital effects and the like. Many other factors will affect BP s earnings quarter by quarter. Actual results may therefore differ significantly from the estimates implied by the application of these rules. These rules of thumb have been developed under existing operating and tax arrangements and are considered to be useful only for 2004 results.

	Full Year
	$ million
Oil Price Brent +/- $1/bbl	570
Gas Henry Hub +/- $ 0.10/mmbtu	110
Refining(a) GIM +/- $ 1/bbl	1,120
Petrochemicals(b) CIM +/- $10/te	200

(a) Refer to Item 4 Information on the Company Segmental Information Refining and Marketing, page 49, for definition of Global Indicator Refining Margin (GIM).

(b) Refer to Item 4 Information on the Company Segmental Information Petrochemicals, page 58, for definition of Chemicals Indicator Margin (CIM).

Table of Contents

Defined Terms and Non-GAAP Financial Measures

Cash Returns

Cash returns are the ratio of the cash returns numerator divided by the cash returns denominator, expressed as a percentage.

Underlying cash returns are the ratio of the cash returns numerator, adjusted for the environment, divided by the cash returns denominator, expressed as a percentage.

The cash returns numerator is operating profit before inventory holding gains and losses adjusted for depreciation, depletion and amortization.

The cash returns denominator is average operating capital employed excluding the fixed asset revaluation adjustment and goodwill consequent upon the Atlantic Richfield and Burmah Castrol acquisitions.

Operating capital employed is capital employed excluding liabilities for current and deferred taxation.

The cash returns numerator, adjusted for the environment, is the cash returns numerator adjusted to oil and natural gas prices and refining margins consistent with BP s planning assumptions.

The nearest equivalent GAAP measures to (i) the cash returns numerator is profit before interest and tax, (ii) the cash return denominator is operating capital employed and (iii) cash returns is return (i.e., profit before interest and tax) on average operating capital employed.

Table of Contents

Management believes that because there will be significant changes in BP s financial reporting due to the adoption of FRS 17 in 2004 and International Financial Reporting Standards in 2005, focusing on cash returns and underlying cash flow (defined below) through this period of change will provide investors with consistent insight into the Group s performance. Cash returns and underlying cash flows are presented for prior periods to provide comparative information for future periods.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Profit before interest and tax			
Exploration and Production	14,669	8,280	12,466
Gas, Power and Renewables	576	2,020	491
Refining and Marketing	2,270	2,582	2,461
Petrochemicals	623	191	(399)
Other businesses and corporate	(184)	(744)	(357)
Group	17,954	12,329	14,662
Customer Facing Businesses (a)	3,469	4,793	2,553
Cash returns numerator			
Exploration and Production	20,681	15,789	18,057
Gas, Power and Renewables	739	548	664
Refining and Marketing	5,489	3,578	5,875
Petrochemicals	1,281	1,170	716
Other businesses and corporate	(143)	(652)	(427)
Group	28,047	20,433	24,885
Customer Facing Businesses (a)	7,509	5,296	7,255
Average operating capital employed			
Exploration and Production	62,539	60,501	58,251
Gas, Power and Renewables	3,636	3,216	3,489
Refining and Marketing	34,298	30,038	26,813
Petrochemicals	13,010	12,257	11,502
Other businesses and corporate	(8,311)	(4,962)	1,437
Group	105,172	101,050	101,492
Customer Facing Businesses (a)	50,944	45,511	41,804
Average cash returns denominator			
Exploration and Production	54,179	49,880	45,324
Gas, Power and Renewables	3,636	3,216	3,489
Refining and Marketing	27,641	22,882	19,001
Petrochemicals	13,010	12,257	11,502
Other businesses and corporate	(8,311)	(4,962)	1,437
Group	90,155	83,273	80,753
Customer Facing Businesses (a)	44,287	38,355	33,992
		(%)	
Return on Average Operating Capital Employed			
Exploration and Production	23	14	21
Gas, Power and Renewables	16	63	14
Refining and Marketing	7	9	9
Petrochemicals	5	2	(3)
Other businesses and corporate	2	15	(25)

Group	17	12	14
Customer Facing Businesses (a)	7	11	6
Cash returns			
Exploration and Production	38	32	40
Gas, Power and Renewables	20	17	19
Refining and Marketing	20	16	31
Petrochemicals	10	10	6
Other businesses and corporate	2	13	(30)
Group	31	25	31
Customer Facing Businesses (a)	17	14	21

(a) Customer Facing Businesses comprises Gas, Power and Renewables, Refining and Marketing and Petrochemicals.

102

Table of Contents

Cash Flow

Adjusted operating cash flow (post-tax) is net cash inflow from operating activities, plus dividends from joint ventures and associated undertakings less the net cash outflow from the servicing of finance and returns on investments less tax paid (excluding tax payments attributable to the sale of fixed assets and businesses or termination of operations).

Underlying operating cash flow is adjusted cash flow after further adjusting for the after-tax cash outflow for incremental discretionary pension funding and oil and natural gas prices and refining margins consistent with BP s planning assumptions.

Free cash flow is adjusted operating cash flow after further adjusting for the after-tax cash outflow for incremental discretionary pension funding less net cash outflow for capital expenditure and financial investment and less net cash outflow for acquisitions and disposals. BP s definition of free cash flow may differ from that of other companies.

Underlying free cash flow is free cash flow adjusted to oil and natural gas prices and refining margins consistent with BP s planning assumptions.

The nearest equivalent GAAP financial measures to the non-GAAP financial measures described above are net cash inflow from operating activities and net cash inflow or outflow. Management believes that underlying cash flow gives a better indication to investors of the cash flow available from the activities of the Group, after meeting tax and interest payments, which is available for capital investment, dividend payments and other discretionary options such as share buybacks and incremental pension scheme funding. Similarly, free cash flow gives a better indication of the cash flows available for dividend payments and other discretionary options after investing in sustaining and growing the capital base of the Group.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Net cash inflow from operating activities	21,698	19,342	22,409
Net cash inflow (outflow)	1,405	(326)	1,035
Adjusted operating cash flow (pre-tax)	21,535	18,997	22,093
Free cash flow	8,705	4,984	5,909

Operating Capital Employed in Service

Operating capital employed in service for the Exploration and Production segment is operating capital employed excluding: the fixed asset revaluation adjustment and goodwill consequent upon the Atlantic Richfield acquisition; our net investment in Russia (TNK-BP); segment tangible fixed assets under construction; and intangible exploration costs.

Management believes that this measure of capital employed, when used in cash return measures, gives an indication of the profitability of the segment s assets that are in service and generating revenue.

The nearest equivalent GAAP financial measures to the non-GAAP financial measures described above are operating capital employed and return on average operating capital employed.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Average operating capital employed	62,539	60,501	58,251
Average operating capital employed in service	39,072	39,660	37,643
		(%)	
Return on average operating capital employed	23	14	21
Cash return	38	32	40

Table of Contents

Gross Margin

Gross margin is Group turnover less cost of sales excluding the impact of inventory holding gains and losses and is a non-GAAP financial measure. Management believes this measure enables investors to better understand BP s trading performance from period to period. The nearest equivalent GAAP measure is historical cost gross margin which is calculated as Group turnover less cost of sales.

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Historical cost gross margin	31,236	24,106	25,325
Gross margin	31,224	22,979	27,217

Net Investment

Net investment is the sum of net cash inflow or outflow for capital expenditure and financial investment and net cash inflow or outflow for acquisitions and disposals.

Business Strategy and Prospects

Through mergers, acquisitions and organic growth, BP has built itself into one of the leading companies in the international oil industry. Our strategy for future growth rests upon four key elements:

- scale: the most attractive projects require very large scale financial, human and physical resources; scale affords the benefits of economies (from for example, procurement, overheads and skills), competitively strong market access and diversification of risk;
- scope: successful companies need to operate globally to access the best opportunities, often in challenging areas;
- capability: successful companies need integrated know-how , the ability to combine technical, commercial and diplomatic skills. This is critical in making large projects happen as activity moves to more politically complex areas;
- capacity: each project or business is different and complex in its own way. Managing a portfolio of these requires a degree of multi-tasking that requires a specific corporate capability.

Having achieved scale, our challenge is to add new cash flow streams to existing ones, with new ones having cash returns at least as good as the existing ones.

One important dimension of our increased scale is the growth in oil and gas reserves. At the end of 1997 prior to the merger with Amoco, BP s proved developed and undeveloped reserves, including 1.8 billion boe in respect of our share of the reserves of joint ventures and associated undertakings, were 8.6 billion boe.

At the end of 2003, reserves have risen to about 18.3 billion boe including 3.3 billion boe of reserves of joint ventures and associated undertakings including our 50% of TNK-BP. Part of this is due to the fact that over the last five years we have replaced about 150% of production.

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.

Building the Group was designed to give us access to economies of scale. An initial route to this was the realisation of the immediate synergies that came from putting together our merged and acquired companies.

Table of Contents

We are now transitioning to a phase of internally generated growth in free cash flow from the high-graded opportunity set of the expanded Group. We have managed the sources and uses of funds over the last few years to position us for this. Since 2000, the year in which we completed the purchase of Atlantic Richfield Company, the price of Brent has averaged $26.7/bbl, somewhat higher than was expected as the period opened. The following table summarizes the four year sources and uses of cash in post-tax terms:

Sources	$ billion	Uses	$ billion
Adjusted operating cash flow	67	Capital expenditure	52
Divestments	25	Acquisitions	14
		Share buybacks	6
		Dividends	20
	92		92

Capital expenditure used about 70% of post-tax operating cash flow from 2000 to 2003, a proportion which is significantly higher than for most other major oil companies. 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 by 6.8% per year in dollar terms, used $20 billion. $6 billion was used for share buybacks. Finally, cash was used to strengthen the financial condition of certain of our pension funds.

Higher oil prices allowed BP to invest in attractive assets and markets at a somewhat faster rate than it might otherwise have been able to do.

We divide our operating business segments into two groupings: Resources Business , namely, Exploration and Production; and Customer Facing Businesses , namely, Refining and Marketing, Petrochemicals, and Gas, Power and Renewables.

Over the last few years we have invested heavily in the new profit centres in the Resources Business. Investment was also significant in the Customer Facing Businesses, into which we invested all the operating cash flow generated by them.

The rationale behind the expansion in the Customer Facing Businesses was:

- an upgrading of quality and a degree of scale was required to get to the point where underlying cash returns from the Customer Facing Businesses could at least be maintained going forward;
- the volatility of earnings is generally lower in Customer Facing Businesses than in the Resources Business in relation to such activities as gas to liquids or heavy oil;
- Customer Facing Businesses allow us to balance risk to returns from the oil price. At very low oil prices (that is around $16/bbl) the Customer Facing Businesses begin to have cash returns in excess of those from the Resources Business. The Resources Business gives us upside potential at higher prices.

The selection of the assets and markets in which we invest is guided by our strategy, which has the objective of maximizing long run shareholder value. The essence of our strategy remains unchanged and is:

- for the Resources Business: to build production with steadily improving underlying cash returns by investing in the largest, lowest cost, new hydrocarbon deposits and managing the decline of existing production assets;

for the Customer Facing Businesses: to expand customer capture, improve quality to offset competitive forces in order to increase cash flow while keeping underlying cash returns at least constant.

BP s results are affected by economic conditions and in particular the oil price. Oil prices are impossible to predict, either on a short or long term basis. There are many uncertainties. One is demand, which has been volatile and has grown by less than 1% per year on average since 1997. Another is the growing level of production and new capacity, both outside the control of OPEC and in some OPEC countries.

Based on our analysis of average Brent oil prices over the last 20 years, it is our view that it is reasonable to use an oil price of $20/bbl for resource allocation to reflect the right balance between the Customer Facing Businesses and the Resources Business, always testing projects at $16/bbl on the downside.

For financial planning, we believe it is necessary to retain sufficient debt capacity to see us through a period of $16/bbl oil prices while not stretching gearing unreasonably, that is to keep it below 35%. This is our contingency plan. As a base case, we now see cash flows balancing at around $20/bbl over the next couple of years. Over time, production rises and capital expenditure declines so that the oil price at which cash flows balance is expected to fall below $20/bbl.

The price of oil will, in large part, determine the size of BP s distributions of excess free cash flows to shareholders over and above our dividend.

Resources Business

Our Resources Business strategy is founded on creating profit centres with leadership positions in the basins in which we operate. Our Resources Business can be viewed in four parts: existing profit centres, new profit centres, our 50% interest in TNK-BP and future growth.

Existing Profit Centres

Our existing profit centres include our operations in Alaska, Egypt, Latin America (including Argentina, 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).

These centres have proved reserves of 9.3 billion boe, including joint ventures and associates, and in 2003 contributed some 2 million boe/d of production. We estimate the decline in production will be around 3% per year from 2004 to 2008. This is in line with a decline of between 3 and 4% per year on average between 2002 and 2004. We expect capital expenditure to decrease over time and unit cash costs to remain stable at an average of around $5.0 per barrel. We expect underlying cash returns for existing profit centres to reduce slightly as the overall production declines.

In managing the production from these existing centres, we focus on:

new projects, primarily in Argentina and the North Sea;

the rate of recovery with a particular emphasis on operational uptime;

the addition of proved reserves. Over the period 2000 to 2003, we have replaced some 75% of the proved developed reserves which have been produced;

Table of Contents

the control of investment and costs made possible by the application of appropriate technology. Finding and development costs in the existing centres have been around $6/boe and the selection of future investments is expected to limit increases to the range of $6 to $7.5/boe.

New Profit Centres

The new profit centres comprise our operations in Asia Pacific (Australia, Vietnam, Indonesia, China), Azerbaijan, Algeria, Angola, Trinidad, Deepwater Gulf of Mexico and Russia.

For new profit centres, the single most important challenge is to ensure that projects start production on time within budgeted capital costs. The major projects are presently on track for their scheduled start of production as shown below:

2004	**2005**
Atlas Methanol, Trinidad	Mad Dog, Gulf of Mexico
In Salah, Algeria	Thunderhorse, Gulf of Mexico
Kizomba A, Angola	Azeri, Azerbaijan
Holstein, Gulf of Mexico	BTC, Azerbaijan
NW Shelf LNG T4, Australia	In Amenas, Algeria
	Trinidad LNG T4, Trinidad

More fields are expected to come on stream in 2006.

In contrast to the existing centres, the new profit centres generally have much lower finding and development costs because the fields are large and new. Unit cash costs are generally also around half the level of those of the existing centres.

We expect capital in service to rise from around 60% in 2004 to a more representative level of 80% in 2008, as production builds, and cash returns to rise accordingly.

Combining both the existing and new profit centres (but excluding Russia), cash returns decline as there is less operating capital employed in service but begin to rise as capital comes into service. Our mid-point estimates of capital expenditure fall within the range of around $8.0 - $8.5 billion per annum in 2005 and 2006, so the free cash flow expands with increased production. Excluding Russia, we estimate that between 2003 and 2008 production will grow by around 5% per year on average.

TNK-BP

We believe that our investment in Russia is attractive and is self-financing in the short term, but also has longer-term strategic importance. The most recent estimates from the International Energy Agency show that for the longer term, which means from 2010 onwards, three areas will supply the bulk of world trade in oil and gas Russia, the Persian Gulf (that is Saudi Arabia, Iran and Iraq) and West Africa. On this basis, our positions in Russia and Angola are important to our long-term strategy.

There are pressures on costs from transportation tariffs, reflecting export constraints, since these tariffs have been set for the oil price conditions of today. They are expected to moderate if oil prices fall. Some of the increases are being offset in TNK-BP by synergies and additional production.

BP receives cash from TNK-BP by way of a dividend, in accordance with our original agreement. We expect that at $20/bbl, TNK-BP will be able to pay dividends equal to 40% of TNK-BP s US GAAP net income, as well as fund its capital expenditure programme.

Future Growth

Capital spending on exploration is expected to rise from an average of $300 million per year for 2000 to 2003 to around $450 million per year in 2004 and beyond. With finding and development costs in the range of $4 to $5 per barrel (based on a rolling five year average), we estimate our medium-term capital expenditure, excluding acquisitions, to be around $8 billion to $8.5 billion per year and longer term expenditure in the range of $8 billion to $9 billion per year (in 2007 and beyond) in order to continue to grow proved reserves and production.

Customer Facing Businesses

We have invested considerably in the Customer Facing Businesses with the main objective of improving our acquisition and retention of customers as a source of enduring value. During their building, these segments produced no surplus cash flow to the Group and our intention now is to target them to produce underlying free cash flow (free cash flow adjusted for oil and gas prices and refining margins) in proportion to their capital employed.

The essence of our strategy is to focus on quality in order to meet continued intense competition.

Capital expenditure, excluding acquisitions, for the Customer Facing Businesses has been in the range of $3.8 billion to $4.3 billion for 2000 to 2003. Operating capital employed was $44 billion in 2003 and for the period 2004 to 2006 we expect the level to remain broadly constant. These figures have not been adjusted for the proposed divestment of Olefins and Derivatives.

Cash returns over the period 2001 to 2003 have varied both as the Customer Facing Businesses have changed and market conditions (after adjusting for refining margins) have moved, but on average have been around 17% including restructuring costs associated with the material acquisitions made since 2000. No adjustments have been made to Petrochemicals or marketing margins.

Projections of market conditions are difficult to make for each segment and so we assume that cash returns for the whole of the Customer Facing Businesses will remain constant over time. Our objective, however, is to improve returns.

In aggregate, our Customer Facing Businesses are an important part of the Group which can further be improved. A key medium-term objective is to bring our capabilities to acquire and retain customers to the level of our technological capabilities.

Capturing the most gross margin and controlling costs are our key operational targets. This set of businesses has long-term potential in not only the United States and Europe (our principal areas of focus) but also in new markets in which we are developing, such as China.

Refining and Marketing

In refining, our objective is to maintain the quality of our US portfolio (rated in the top quartile by the Solomon Net Margin Index). In Europe, improvements to the configuration of our portfolio are still needed. Our operational focus is keeping availability high (the rate was 95.5% in 2003), controlling operating costs and reducing the unit cost of goods sold. Our capital expenditure is reducing slightly as investments in relation to clean air and clean fuels are decreasing. We intend to continue to limit our exposure to refining assets.

In oil products marketing, we are continuing to expand the reach of our new convenience format, BP Connect, and introducing new products (such as premium fuels like BP Ultimate). Sales are showing strong trends.

Petrochemicals

Petrochemicals cash returns have been around 10% over the period 2000 to 2003. Our objective is to improve these returns without relying on a better trading environment. In order to do so, we intend to continue our programme of divestitures and our focus on reliability (which was 95% in 2003) and cost reductions.

We are now managing our Petrochemicals businesses in two portfolios: A&A (PX, PTA and acetic acid) and O&D. Operating capital employed in A&A is around $5 billion and in O&D it is around $8 billion.

Historically, aromatics and acetyls, which have significantly higher market shares and more proprietary technological content, have generated better returns. They are also positioned to benefit from the high growth in Asian markets. Our focus is therefore to invest more in these products while maintaining capital at very low levels in O&D. We believe our O&D portfolio has competitive advantages in the O&D part of the industry. Acceptable returns will, however, be very dependent upon utilization rates (which are driven by demand) and cost of feedstock, given its competitive intensity and fragmentation. On April 27, 2004, we announced our intention to set up a separate corporate entity for the O&D businesses. It is our intention to make a public offering of this new entity at an appropriate time. Based on the estimated lead time required for such a transaction, and depending on market circumstances, we would aim to make such an offering in the second half of 2005. We intend to retain and grow the A&A businesses, which will be transferred to the Refining and Marketing segment on January 1, 2005.

Gas, Power and Renewables

This segment comprises gas marketing and trading, NGLs and LNG. This is our smallest segment in financial terms, its financial results are comprised of the marketing margins only for gas and gas products. This segment plays a vital long-term role in the development of customers for our gas so that markets are available for equity gas when produced.

Our gas sales have been increasing at 22% per year from 2000 to 2003 and we expect growth to continue at a rate of 3 to 5% per year for the next five years, which is above global gas demand. NGL sales have increased at a rate of 13% per year over the same period, and BP is the leading marketer of NGLs in the United States. LNG sales have also been growing; last year we took material steps in implementing our strategy with the startup of Train 3 in Trinidad and the securing of access to new markets in the Atlantic and Pacific Basins. During 2003, we supplied 1.4 billion cubic feet per day of equity gas into LNG plants, up from 0.7 billion cubic feet per day in 2000. We expect to add a further 0.8 billion cubic feet per day by 2006, bringing our total volume to over 2.2 billion cubic feet per day.

Capital expenditure, acquisitions and divestments

Our plans for the future level of investment and divestment are shown on the table below:

	Years ended December 31,		
	2003	2004	2005
		($ billion)	
Capital expenditure			
Exploration and Production	9.7	9.0	

Gas, Power and Renewables	0.3	0.6	
Refining and Marketing	3.0	2.8	
Petrochemicals	0.8	0.9	
Other	0.2	0.2	
	14.0	13.5	12.0-12.5
Acquisitions	6.0	1.4	
Divestments	(6.4)	(3.0-4.0)	(1.0)

Table of Contents

We expect capital expenditure to decrease to a level of $12 billion to $12.5 billion per year in 2005 and 2006 and divestment to a level of around $1 billion per year, mostly due to routine portfolio upgrading. These figures exclude the effects of the possible spin-off of our O&D business. The only currently identified acquisition over this period is the purchase of the remainder of Solvay s stake in our high-density polyethylene joint venture, should Solvay decide to exercise their put option to us.

Cash returns

Cash returns for the Group decreased from 2001 to 2003, as the amount of capital not in service in the Exploration and Production segment remained high. They should improve as we go forward and we expect the average return for 2004 to 2006 to be equal to that for 2001 to 2003.

Dividends and Other Distributions to Shareholders and Gearing

The Board intends to continue with a progressive dividend policy. In establishing the level of dividend the Board uses its discretion but is guided by several considerations, including:

- the actual prevailing circumstances of the Group, including its cash flows, indebtedness and results;
- the future expected sustainable profit of the Group, excluding amortization of the fixed asset valuation adjustment and goodwill consequent upon the Atlantic Richfield and Burmah Castrol acquisitions and inventory holding gains and losses, at underlying conditions of $20/bbl Brent, $3.50/mmbtu Henry Hub natural gas and a global indicator refining margin of $2.70/bbl;
- the effect of circumstances which may require planning assumptions to be modified;
- our track record of dividend growth which has been 6.8% per year in dollar terms since 1999, the year in which we started to announce our dividends in dollars.

Importantly, these considerations are assessed in the broader context of our approach to long-term value creation based on cash returns. Accordingly, we remain focused on ensuring that the spread between our return and our weighted average cost of capital is optimized.

Therefore, we manage our gearing to a level of 25-30%, assuming oil prices are about $20/bbl, in order to provide the appropriate cushion against potential oil price volatility, but also to prevent an increase in our weighted average cost of capital, which would result from an over-capitalised balance sheet. This gearing range could be extended to 35% if oil prices go down to $16/bbl.

In periods of high oil prices, subject to unforeseen circumstances the Group generates significant excess free cash flow after capital expenditure and dividends. Rather than using this cash to reduce debt below our target gearing levels, we intend to return 100% of this excess free cash flow to our investors, for as long as oil prices remain above $20/bbl, all other things being appropriate. While it is possible that some of the excess might be used, for example, for material acquisitions if we saw opportunities that fit our strategy, we see no such opportunities at present.

Our plan is to continue, subject to market conditions, our programme of share buybacks. Since the completion of the Atlantic Richfield acquisition in 2000 until the end of 2003 we have repurchased some 775 million shares at a cost of $6 billion, reducing the number of shares in issue (after accounting for the issuance of shares under employee stock programmes) by 2.5%. During the first quarter of 2004, we bought back 154.7 million shares, at a cost of $1.25 billion.

Table of Contents

Assessing performance

We have three targets:

- to underpin growth by a focus on performance, particularly on cash returns, investing at a rate appropriate for long term growth;
- to increase the dividend in the light of the considerations outlined below;
- to distribute to shareholders 100% of all post-tax cash flows in excess of investment and dividend needs, generally when the price of oil is above $20/bbl, all other things being appropriate.

We presently track the first of these targets through five strategic indicators. Strategic indicators are estimates of outcomes and are not targets; they are parameters by which we assess the performance of the business. We keep these indicators under review and if we find a better way of measuring the achievement of our targets, we will change the indicators accordingly.

- Oil and gas production. We currently estimate the rate of growth of oil and gas production at an average of around 5% per year between 2003 and 2008, excluding production from TNK-BP, and at an average of around 7% per year including TNK-BP. Our estimates for the years 2005 to 2008 do not include unidentified projects or exploration successes but do include our view of some reserves which are currently not booked as proved;
- Cash returns. We expect an improvement in underlying cash returns of approximately two percentage points between 2003 and 2006;
- Operating capital employed. We expect an increase in operating capital employed of around 15% between 2003 and 2006;
- Finding and development costs. We expect to keep the five year rolling average of finding and development costs in the range of $4 to $5 per boe over the period to 2006;
- Capital expenditure. We expect capital expenditure of around $13.5 billion in 2004, $12 to $12.5 billion over 2005 to 2006 and around $12 to $13 billion beyond 2007.

Table of Contents

The Effect of Accounting Changes in 2004 on Prior Period Financial Information

Employee Share Ownership Plan Trusts

The Group has adopted UITF Abstract No. 38 Accounting for Employee Share Ownership Plan (ESOP) Trusts with effect from January 1, 2004. The effect of adopting the Abstract is to transfer BP ordinary shares held by the ESOP Trust from fixed assets - investments to BP shareholders interest.

	Restated			Reported		
Balance sheet at December 31,	2003	2002	2001	2003	2002	2001
			($ million)			
Fixed assets - Investments	17,458	10,652	11,697	17,554	10,811	11,963
Years ended December 31,						
Net cash inflow (outflow)	1,405	(326)	1,035	1,342	(344)	1,002

Transfer of Natural Gas Liquids Activities

With effect from January 1, 2004, the natural gas liquids (NGL) activities were transferred from Exploration and Production to Gas, Power and Renewables. The adjustments between these two segments for 2003, 2002 and 2001 are set out below.

	2003	2002	2001
		($ million)	
Years ended December 31,			
Group operating profit	106	68	84
Share of profits of joint ventures			
Share of profits of associated undertakings			
Total operating profit	106	68	84
Exceptional items			
Profit before interest and tax	106	68	84
Inventory holding gains (losses)			
Capital expenditure and acquisitions	82	40	8
Balance sheet at December 31,			

Operating capital employed	389	322	314
Tangible assets	289	289	287

Table of Contents

Adoption of New Accounting Standard for Pensions and Other Postretirement Benefits

With effect from January 1, 2004 the Group has adopted Financial Reporting Standard No. 17 Retirement Benefits . Financial information for 2003 and 2002 has been restated. Financial information for 2001 and earlier years has not been restated.

Years ended December 31,	As restated		As reported	
	2003	2002	2003	2002
	($ million)			
Turnover	236,045	180,186	236,045	180,186
Less: Joint ventures	3,474	1,465	3,474	1,465
Group turnover	232,571	178,721	232,571	178,721
Cost of sales	201,335	154,615	202,029	154,401
Production taxes	1,723	1,274	1,723	1,274
Gross profit	29,513	22,832	28,819	23,046
Distribution and administration expenses	14,072	12,632	14,072	12,632
Exploration expense	542	644	542	644
	14,899	9,556	14,205	9,770
Other income	786	641	786	641
Group operating profit	15,685	10,197	14,991	10,411
Share of profits of joint ventures	924	347	924	347
Share of profits of associated undertakings	514	617	514	617
Total operating profit (a)	17,123	11,161	16,429	11,375
Profit (loss) on sale of businesses or termination of operations	(28)	(33)	(28)	(33)
Profit (loss) on sale of fixed assets	859	1,201	859	1,201
Profit before interest and tax	17,954	12,329	17,260	12,543
Interest expense	644	1,067	851	1,279
Other finance expense	547	73		
Profit before taxation	16,763	11,189	16,409	11,264
Taxation	6,111	4,317	5,972	4,342
Profit after taxation	10,652	6,872	10,437	6,922
Minority shareholders interest equity	170	77	170	77
Profit for the year	10,482	6,795	10,267	6,845
Dividend requirements on preference shares	2	2	2	2
Profit for the year applicable to ordinary shares	10,480	6,793	10,265	6,843
Profit per ordinary share cents				
Basic	47.27	30.33	46.30	30.55

Diluted	46.72	30.19	45.87	30.41
Dividends per ordinary share cents	26.00	24.00	26.00	24.00
Average number outstanding of 25 cents ordinary shares (in thousands)	22,170,741	22,397,126	22,170,741	22,397,126

(a) Total operating profit

Exploration and Production (b)	13,756	9,006	13,940	9,209
Gas, Power and Renewables (b)	582	469	478	405
Refining and Marketing	2,483	1,969	2,292	1,921
Petrochemicals	585	447	623	541
Other businesses and corporate	(283)	(730)	(904)	(701)
	17,123	11,161	16,429	11,375

(b) Restatement includes the transfer of the natural gas liquids (NGL) activities from Exploration and Production to Gas, Power and Renewables.

113

Table of Contents

Balance sheet at December 31, 2003	Restated	Reported
	($ million)	
Fixed assets		
Intangible assets	13,642	13,642
Tangible assets	91,911	91,911
Investments (a)	17,458	17,554
	123,011	123,107
Current assets	47,651	54,465
Creditors - amounts 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
Creditors - amounts falling due after more than one year	18,959	18,959
Provisions for liabilities and charges		
Deferred taxation	14,371	15,273
Other provisions	8,815	15,693
Net assets excluding pension and other postretirement benefit balances	77,933	77,063
Defined benefit pension plan surplus	1,021	
Defined benefit pension plan and other postretirement benefit plan deficits	(7,510)	
Net assets	71,444	77,063
Minority shareholders interest	1,125	1,125
BP shareholders interest (a)	70,319	75,938
Balance sheet at December 31, 2002		
Fixed assets		
Intangible assets	15,566	15,566
Tangible assets	87,682	87,682
Investments (a)	10,652	10,811
	113,900	114,059
Current assets	41,167	45,066
Creditors - amounts falling due within one year	46,301	46,301
Net current liabilities	(5,134)	(1,235)
Total assets less current liabilities	108,766	112,824
Creditors - amounts falling due after more than one year	15,377	15,377
Provisions for liabilities and charges		
Deferred taxation	13,514	13,514
Other provisions	7,978	13,886
Net assets excluding pension and other postretirement benefit balances	71,897	70,047
Defined benefit pension plan surplus	221	
Defined benefit pension plan and other postretirement benefit plan deficits	(7,831)	

Net assets	64,287	70,047
Minority shareholders interest	638	638
BP shareholders interest (a)	63,649	69,409

(a) Restatement includes the recategorization of shares held by ESOP Trusts from Fixed assets - Investments to BP shareholders interest.

Table of Contents

Reconciliation of Non-GAAP Financial Measures

(i) Reconciliation of profit before interest and tax to cash returns numerator and cash returns numerator, adjusted for environment	Years ended December 31,		
	2003	2002	2001
		($ million)	
Group			
Profit before interest and tax	17,954	12,329	14,662
Inventory holding (gains) losses	(16)	(1,129)	1,900
Exceptional items	(831)	(1,168)	(535)
Operating profit before inventory holding (gains) losses	17,107	10,032	16,027
Depreciation, depletion and amortization	10,940	10,401	8,858
Cash returns numerator	28,047	20,433	24,885
Adjustment for oil and natural gas price environment	(7,709)	(1,895)	(3,580)
Adjustment for Global Indicator Refining Margin	(1,334)	671	(1,461)
Cash returns numerator, adjusted for environment	19,004	19,209	19,844
Exploration and Production			
Profit before interest and tax	14,669	8,280	12,466
Inventory holding (gains) losses	(3)	(3)	6
Exceptional items	(913)	726	(195)
Operating profit before inventory holding (gains) losses	13,753	9,003	12,277
Depreciation, depletion and amortization	6,928	6,786	5,780
Cash returns numerator	20,681	15,789	18,057
Remove TNK-BP	(569)	(89)	(10)
Adjustment for oil and natural gas price environment	(7,172)	(2,505)	(5,400)
Cash returns numerator, adjusted for environment	12,940	13,195	12,647
Gas, Power and Renewables			
Profit before interest and tax	576	2,020	491
Inventory holding (gains) losses	(6)	(51)	81
Exceptional items	6	(1,551)	
Operating profit before inventory holding (gains) losses	576	418	572
Depreciation, depletion and amortization	163	130	92
Cash returns numerator	739	548	664

Table of Contents

(i) Reconciliation of profit before interest and tax to cash returns numerator and cash returns numerator, adjusted for environment (continued)

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Refining and Marketing			
Profit before interest and tax	2,270	2,582	2,461
Inventory holding (gains) losses	48	(1,049)	1,583
Exceptional items	213	(613)	(471)
Operating profit before inventory holding (gains) losses	2,531	920	3,573
Depreciation, depletion and amortization	2,958	2,658	2,302
Cash returns numerator	5,489	3,578	5,875
Adjustment for Global Indicator Refining Margin	(1,334)	671	(1,461)
Cash returns numerator, adjusted for environment	4,155	4,249	4,414
Petrochemicals			
Profit before interest and tax	623	191	(399)
Inventory holding (gains) losses	(55)	(26)	230
Exceptional items	(38)	256	297
Operating profit before inventory holding (gains) losses	530	421	128
Depreciation, depletion and amortization	751	749	588
Cash returns numerator	1,281	1,170	716
Other businesses and corporate			
Profit before interest and tax	(184)	(744)	(357)
Inventory holding (gains) losses			
Exceptional items	(99)	14	(166)
Operating profit before inventory holding (gains) losses	(283)	(730)	(523)
Depreciation, depletion and amortization	140	78	96
Cash returns numerator	(143)	(652)	(427)

Table of Contents

(i) Reconciliation of profit before interest and tax to cash returns numerator and cash returns numerator, adjusted for environment (concluded)

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Customer facing businesses			
Profit before interest and tax	3,469	4,793	2,553
Inventory holding (gains) losses	(13)	(1,126)	1,894
Exceptional items	181	(1,908)	(174)
Operating profit before inventory holding (gains) losses	3,637	1,759	4,273
Depreciation, depletion and amortization	3,872	3,537	2,982
Cash returns numerator	7,509	5,296	7,255
Adjustment for Global Indicator Refining Margin	(1,334)	671	(1,461)
Cash returns numerator, adjusted for environment	6,175	5,967	5,794

117

Table of Contents

(ii) Reconciliation of operating capital employed to cash returns denominator and operating capital employed in service	Years ended December 31,		
	2003	2002	2001
		($ million)	
Group			
Capital employed	93,769	86,295	86,910
Liabilities for current and deferred taxation	16,068	14,211	14,815
Operating capital employed	109,837	100,506	101,725
Acquisition adjustment	(13,362)	(16,672)	(18,882)
Cash returns denominator	96,475	83,834	82,843
Exploration and Production			
Operating capital employed	63,618	61,460	59,832
Acquisition adjustment	(6,983)	(9,737)	(11,506)
Cash returns denominator	56,635	51,723	48,326
Net investment in Russia	(3,583)	(766)	(297)
Tangible fixed assets under construction	(10,406)	(7,482)	(3,863)
Intangible exploration assets (net of acquisition adjustment)	(3,792)	(4,184)	(4,138)
Operating capital employed in service	38,854	39,291	40,028
Gas, Power and Renewables			
Operating capital employed	4,292	2,979	3,439
Acquisition adjustment			
Cash returns denominator	4,292	2,979	3,439
Refining and Marketing			
Operating capital employed	35,111	33,484	25,319
Acquisition adjustment	(6,379)	(6,935)	(7,376)
Cash returns denominator	28,732	26,549	17,943
Petrochemicals			
Operating capital employed	13,484	12,536	11,996
Acquisition adjustment			
Cash returns denominator	13,484	12,536	11,996
Other businesses and corporate			
Operating capital employed	(6,668)	(9,953)	1,139
Acquisition adjustment			
Cash returns denominator	(6,668)	(9,953)	1,139

Table of Contents

(iii) Reconciliation of net cash inflow from operating activities to adjusted operating cash flow and underlying operating cash flow	Years ended December 31,		
	2003	2002	2001
		($ million)	
Net cash inflow from operating activities	21,698	19,342	22,409
Dividends received from joint ventures	131	198	104
Dividends received from associated undertakings	417	368	528
Net cash outflow from servicing of finance and returns on investments	(711)	(911)	(948)
Adjusted operating cash flow (pre-tax)	21,535	18,997	22,093
Tax paid on operations*	(4,681)	(2,969)	(4,290)
Adjusted operating cash flow (post-tax)	16,854	16,028	17,803
Post-tax discretionary pension funding adjustment	1,646	46	47
Adjustment for oil and natural gas price environment	(4,577)	(1,125)	(2,126)
Adjustment for Global Indicator Refining Margin	(934)	470	(1,023)
Underlying operating cash flow (post-tax)	12,989	15,419	14,701
*Components of tax payments			
Tax paid on operations	(4,681)	(2,969)	(4,290)
Tax (paid) refunded on exceptional items	(123)	(125)	(370)
Total tax paid	(4,804)	(3,094)	(4,660)
Reconciliation of net cash flow to free cash flow and underlying free cash flow			
Net cash inflow (outflow)	1,405	(326)	1,035
Equity dividends paid	5,654	5,264	4,827
Post-tax discretionary pension funding adjustment	1,646	46	47
Free cash flow	8,705	4,984	5,909
Adjustment for oil and natural gas price environment	(4,577)	(1,125)	(2,126)
Adjustment for Global Indicator Refining Margin	(934)	470	(1,023)
Underlying free cash flow	3,194	4,329	2,760
Reconciliation of historical cost gross margin to gross margin			
Turnover	232,571	178,721	174,218
Cost of sales	201,335	154,615	148,893
Historical cost gross margin	31,236	24,106	25,325
Inventory holding gains and losses	12	1,127	(1,892)
Gross margin	31,224	22,979	27,217

Table of Contents

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 more significant accounting policies are summarized in Note 1 of the Notes to Financial Statements on page F-9. There have been no changes in accounting policy during 2003.

Inherent in the application of many of these accounting policies in the preparation of 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 for the results of the Group and should be read in conjunction with Note 1 of the Notes to Financial Statements.

The areas that require the most significant judgements and estimates 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.

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 until such time as either exploration drilling is determined to be successful, at which point the costs are transferred to proved properties not yet sanctioned within intangible assets, or it is unsuccessful and all costs are written off. Licence and property acquisition costs are not subject to periodic assessments for impairment.

For exploration 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. This 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 that are in areas where a 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 offshore exploration discoveries, it is not unusual to have exploration wells remain suspended on the balance sheet for several years while additional appraisal drilling and seismic work on the potential oil and gas field are performed or while the

Table of Contents

optimum development plans and timing are established. As with licence and property acquisition costs, there is no periodic impairment assessment of suspended exploration well costs. All such carried costs are subject to regular technical, commercial and management review 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 value of licence and property acquisition costs and exploration and appraisal costs are transferred to production assets within tangible assets.

The capitalized exploration and development costs for proved oil and gas properties (which include the costs of drilling successful 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 impairment discussion 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.

Oil and Gas Reserves

As indicated in Item 4 Information on the Company Exploration and Production under the heading Reserves and Production on page 22, the Company 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.

Assessment of the value in use of a potentially impaired oil or natural gas property requires an estimate of the recoverable value during its expected life, which will typically extend for many years. As a consequence, it is appropriate to base this assessment on estimated long-term oil and gas prices and an estimate of the recoverable reserves attributed to BP s interest in the property. For this purpose we take a combination of the average price achieved over the past ten years and Management s view of the long-term price range as being indicative of future prices. In making this assessment a discount rate of 9% has been used, which represents the Group s pre-tax weighted average cost of capital together with a Brent oil price of $20 per barrel and a Henry Hub gas price of $3.50 per mmbtu. 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. The information in Item 18 Financial Statements Supplementary Oil and Gas Information on page S-1 Standardized measures of discounted future net cash flows and changes therein relating to proved oil and gas reserves was prepared for 2003 using a discount rate of 10%, a year-end Brent oil price of $30.10 per barrel and a Henry Hub gas price of $5.76 per mmbtu as required by FASB Statement of Financial Accounting Standards (SFAS) No. 69 Disclosures about Oil and Gas Production Activities. The purpose of the Standardized Measure under SFAS No. 69 Disclosures about Oil and Gas Producing Activities is to achieve some of the characteristics of a fair market value without the extreme subjectivity inherent in direct estimation of market value, i.e., mark-to-market. Although it cannot be considered an estimate of fair market value, the standardized measure takes the variables of changes in reserves quantities, selling prices based on the year end price, production costs as incurred during the year and tax rates into account.

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. See Group Operating Results within this item for a discussion of impairment charges recognized in 2003. 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 $4,500 million of carry-forward tax losses in the UK, which are available to offset against future taxable income. To date, tax assets have been recognized on $285 million of those losses (i.e., to the extent that it is regarded as more likely than not that suitable taxable income will arise). 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 the near term.

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. 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.

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 year end 2003 was 2.5%, the same as at the end of 2002. 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, 2003 was 2.5%, the same as 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 other postretirement plans are important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. The assumptions used may vary from year-to-year, which will affect future results of operations. Any differences between these assumptions and the actual outcome also impact 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 liability or asset recorded on the Group s balance sheet, and pension expense for the following year.

The pension and other postretirement costs charged or credited to income for the year ended December 31, 2003 and the prepayments and provisions for unfunded pension and postretirement schemes at December 31, 2003 have been determined on the basis of Statement of Standard Accounting Practice No. 24 Accounting for Pension Costs (SSAP 24). 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.

Table of Contents

The effect of adopting FRS 17 is to increase profit before taxation for 2003 by $354 million and to reduce BP shareholders interest at December 31, 2003 by $5,523 million. The cost recognized for providing pension and other postretirement benefits on a FRS 17 basis in 2003 is $582 million; in 2004 it is expected to be $1,009 million.

The pension assumptions at December 31, 2003 and 2002 under FRS17 are summarized below.

	UK		Other		USA	
	2003	2002	2003	2002	2003	2002
			(%)			
Rate of return on assets	7.0	7.0	6.0	6.0	8.0	8.0
Discount rate	5.5	5.75	5.5	5.75	6.0	6.75
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 2004	(270)	270
Discount rate:		
Effect on pension expense in 2004	(320)	420
Effect on pension obligation at December 31, 2003	(3,290)	4,240

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.

	2004	2005	2006	2007	2008	2009 and subsequent years
				(%)		
Beneficiaries aged under 65	11	9	8	7	6	5
Beneficiaries aged over 65	14	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 2004	92	(73)
Effect on postretirement obligation at December 31, 2003	561	(451)

Accounting Policy Changes in 2004

As indicated under the previous heading, BP has changed its accounting policies for pensions and other postretirement benefits. In addition, 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 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 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 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 December 31, 2003 by $96 million; the impact on profit before taxation for 2003 is negligible.

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, which automatically becomes law in all EU countries, requires all EU companies listed on a 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 published 15 revised standards in December 2003, and the remaining standards of its stable platform on March 31, 2004. The stable platform is the set of IFRSs to be adopted on a mandatory basis in 2005. A process of endorsement of IFRSs has been established by the EU for completion in due time to allow adoption by companies in 2005, but objections to certain IFRSs by certain EU member states may disrupt this process.

BP has established a project team involving representatives of business segments and functions to plan for and achieve a smooth transition to IFRS. The project team is looking at all implementation aspects, including changes to accounting policies, systems impacts and the wider business issues that may arise from such a fundamental change. We currently expect that the Group will be fully prepared for the transition in 2005.

The Group has not yet determined the full effects of adopting IFRS. Our preliminary view is that the major differences between our current accounting practice and IFRS will probably be in respect of hedge accounting, accounting for embedded derivatives and other items falling within the scope of the financial instruments standards, accounting for business combinations, deferred tax and share-based payments.

Table of Contents

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 Note 48 of Notes to Financial Statements.

Impact of New US Accounting Standards

Financial instruments: In April 2003, the FASB issued SFAS No. 149 Amendment of Statement 133 on Derivative Instruments and Hedging Activities (SFAS 149). SFAS 149 amends and clarifies the financial accounting and reporting of derivative instruments and hedging activities under SFAS 133. SFAS 149 applies to contracts entered into or modified after June 30, 2003, and hedging relationships designated after June 30, 2003.

In May 2003, the FASB issued SFAS No. 150 Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity (SFAS 150). SFAS 150 establishes standards for classifying and measuring certain financial instruments that have characteristics of both liabilities and equity. SFAS 150 applies to instruments entered into or modified after May 31, 2003. For instruments existing at May 31, 2003, SFAS 150 is effective for accounting periods beginning after June 15, 2003.

The adoption of SFAS 149 and SFAS 150 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.

Consolidation: 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. Interpretation 46 applies to variable interest entities created or acquired after January 31, 2003. For variable interest entities existing at January 31, 2003, Interpretation 46 is effective for accounting periods ending after December 15, 2003.

The Group currently has several ships under construction which will be 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. At December 31, 2003 consolidation of these entities would result in an increase in tangible assets and finance debt of $217 million. 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.

Guarantees: In November 2002, the FASB issued FASB Interpretation No. 45 Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others (Interpretation 45). Interpretation 45 elaborates on existing disclosure requirements for guarantees and clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. The initial recognition and measurement provisions of Interpretation 45 apply on a prospective basis to guarantees issued or modified after December 31, 2002.

Tangible assets: The Securities and Exchange Commission requested the FASB to consider whether oil and natural gas mineral rights held under lease or other contractual arrangement should be classified on the balance sheet as a tangible asset (property, plant and equipment) or as an intangible asset

Table of Contents

(exploration expenditure). At its March 2004 meeting, the EITF reached a consensus on Issue No. 04-2 (Whether Mineral Rights are Tangible or Intangible Assets) that all mineral rights should be considered tangible assets for accounting purposes. In April 2004, the FASB issued FASB Staff Position Nos. FAS 141-1 and FAS 142-1 (Interaction of FASB Statements No. 141, Business Combinations, and No. 142, Goodwill and Other Intangible Assets, and EITF Issue No. 04-2, Whether Mineral Rights are Tangible or Intangible Assets), which amended SFAS 141 and 142 to remove mineral rights as an example of an intangible asset consistent with the EITF s consensus. The EITF consensus and the FASB Staff Position are effective for reporting periods beginning after April 29, 2004.

In accordance with Group accounting practice, exploration licence acquisition costs are initially capitalized 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, 2003, exploration licence acquisition costs included in the Group s intangible fixed assets amounted to approximately $600 million, net of accumulated depletion and the Group s tangible fixed assets amounted to approximately $1.3 billion, net of accumulated depletion.

Table of Contents

ITEM 6 DIRECTORS, SENIOR MANAGEMENT AND EMPLOYEES

DIRECTORS AND SENIOR MANAGEMENT

The following lists the Company s directors and senior management as at June 23, 2004.

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, Gas, Power and Renewables	April 2002
Dr D C Allen	Executive director (Group chief of staff)	February 2003
P B P Bevan	Group general counsel	September 1992
I C Conn	Chief executive, Petrochemicals	November 2002
Dr A B Hayward	Executive director (Chief executive, Exploration and Production)	February 2003
J A Manzoni	Executive director (Chief executive, Refining and Marketing)	February 2003
Dr B E Grote	Executive director (Chief financial officer)	August 2000
R L Olver	Executive director (Deputy group chief executive)	January 1998
J H Bryan	Non-executive director (a)(c)	December 1998
A Burgmans	Non-executive director	February 2004
E B Davis, Jr	Non-executive director (a)(b)(c)	December 1998
Dr D S Julius	Non-executive director (a)(b)	November 2001
C F Knight	Non-executive director (a)(b)	October 1987
Dr W E Massey	Non-executive director (a)(d)	December 1998
H M P Miles	Non-executive director (a)(c)(d)	June 1994
Sir Robin Nicholson	Non-executive director (a)(b)	October 1987
M H Wilson	Non-executive director (a)(c)(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.

Table of Contents

Mr R F Chase retired as an executive director on April 23, 2003. Mr F A Maljers retired as a non-executive director on April 15, 2004. Mr R L Olver will resign as an executive director on July 1, 2004. At the Company s Annual General Meeting (AGM) the following directors retired, and offered themselves for re-election and were duly re-elected: The Lord Browne of Madingley, Dr B E Grote, Mr H M P Miles, Sir Robin Nicholson, Mr R L Olver and Sir Ian Prosser. Mr A Burgmans was appointed as a non-executive director on February 5, 2004, offered himself for election as a director at the AGM and was duly elected. 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. This replaced the previous requirement that directors who had held office for three years or more or since they were elected or re-elected to retire from office at the Company s AGM.

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

P D Sutherland, KCMG Peter Sutherland (58) 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 Investor AB and The Royal Bank of Scotland Group. He was awarded an honorary KCMG in 2003.

Sir Ian Prosser Sir Ian (60) joined BP s board in 1997 and was appointed non-executive deputy chairman in 1999. He retired as chairman of InterContinental Hotels Group PLC on December 31, 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 from 1995 to 1999. In 1999, he was appointed a non-executive director of GlaxoSmithKline.

The Lord Browne of Madingley, FREng Lord Browne (56) joined BP in 1966 and subsequently held a variety of Exploration and Production and Finance posts in the UK, US 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 (49) joined BP in 1982, having previously worked at Exxon. He undertook a series of roles in Exploration and Production, Refining and Marketing and Finance before being appointed in 1997 as group vice president in Refining and Marketing. In 1999 he became a group vice president in Exploration and Production and was appointed executive vice president and chief executive of BP s Gas, Power and Renewables in April 2002. Mr. Alexander will become chief executive of BP s Petrochemicals segment with effect from July 1, 2004.

Dr D C Allen David Allen (49) 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 (60) 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.

I C Conn Iain Conn (41) joined BP in 1985. After a series of roles in oil trading, Exploration and Production, Refining and Marketing and the corporate centre, in 2000 he became group vice president responsible for BP s marketing operations in New Markets and then for Europe in 2001. During 2001 he led the integration of Veba Oel and associated transactions and had group vice president responsibility for the Europe region. In November 2002 he was appointed chief executive of BP s Petrochemicals segment. With effect from July 1, 2004, he will become a group executive officer.

Table of Contents

Dr B E Grote Byron Grote (56) joined BP in 1987 following the acquisition of Standard Oil (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 Petrochemicals in 2000. He was appointed an executive director of BP in 2000 and chief financial officer in 2002.

Dr A B Hayward Tony Hayward (47) 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 became an executive vice president in 2002. He was appointed chief operating officer for Exploration and Production in 2002 and chief executive for Exploration and Production as well as an executive director of BP in 2003. He is a non-executive director of Corus Group.

J A Manzoni John Manzoni (44) joined BP in 1983. He undertook a number of roles in BP s North Sea and Alaskan operations, as well as in investor relations, before becoming group vice president for European marketing. In 2000, he became BP regional president for the Eastern US and in 2001 an executive vice president and chief executive for Gas, Power and Renewables. He was appointed chief executive of Refining and Marketing in 2002 and an executive director of BP in 2003. He will become a non-executive director of SAB Miller p.l.c. with effect from August 1, 2004.

R L Olver Dick Olver (57) joined BP in 1973. His early career involved a wide range of oil, gas and refining projects in the UK, Canada, the Middle East and Norway. In 1990, he was made chief of staff to the chairman of BP and head of corporate strategy. In 1992, he led BP s growth in deepwater exploration in the Gulf of Mexico and was appointed deputy chief executive of Exploration and Production in 1995. He became chief executive of Exploration and Production and an executive director of BP in 1998, and deputy group chief executive in 2003. He is a non-executive director of Reuters Group. He will retire from BP on July 1, 2004.

J H Bryan John Bryan (67) joined BP s board in 1998, having previously been a director of Amoco. He serves on the boards of Bank One Corporation, General Motors Corporation and Goldman Sachs. He retired as chairman of Sara Lee Corporation in 2001. He is chairman of Millennium Park Inc., Chicago.

A Burgmans Antony Burgmans (57) joined BP s board in February 2004. He was appointed to the board of Unilever in 1991 and became vice chairman of Unilever NV in 1999. He is chairman of Unilever NV and vice chairman of Unilever plc. He is also a member of the supervisory board of ABN AMRO Bank NV and the international advisory board of Allianz AG.

E B Davis, Jr Erroll B Davis, Jr (59) joined BP s board in 1998, having previously been a director of Amoco. He is chairman and chief executive officer of Alliant Energy. He is a director of the Wisconsin Association of Manufacturers and Commerce, the Edison Electric Institute and the Electric Power Research Institute. He is a non-executive director of PPG Industries and a lifetime member of the board of trustees of Carnegie Mellon University. In June 2004, he became a non-executive director of Union Pacific Corporation and an independent director of the US Olympic Committee.

Dr D S Julius, CBE DeAnne Julius (55) joined BP s board in 2001. 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 the Court of the Bank of England, Lloyds TSB, Serco and the Roche Group.

C F Knight Charles Knight (68) joined BP s board in 1987. He was employed by Lester B Knight and Associates of Chicago, consulting engineers, from 1961 to 1973. In 1972, he joined Emerson Electric Co. and became chairman in 1974. He is a non-executive director of Anheuser-Busch, Morgan Stanley Dean Witter, SBC Communications and IBM.

Table of Contents

Dr W E Massey Walter Massey (66) 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 (68) joined BP s board in 1994. He was appointed deputy managing director of Cathay Pacific in 1976, managing director in 1978 and chairman in 1984. 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 and non-executive chairman of Johnson Matthey PLC and a director of BP Pension Trustees Ltd.

Sir Robin Nicholson, FREng, FRS Sir Robin (69) joined BP s board in 1987. He represents the board on the BP Technology Advisory Council. In 1976, he became managing director of Inco Europe Limited. He was chief scientific advisor in the Cabinet Office from 1981 to 1985. Between 1986 and 1996 he was an executive director of Pilkington. He is a non-executive director of Rolls-Royce p.l.c. and pro-chancellor of UMIST.

M H Wilson Michael Wilson (66) joined BP s board in 1998, having previously been a director of Amoco. He was a member of the Canadian Parliament from 1979 to 1983 and held various ministerial posts, including Industry, Science and Technology, Finance, and International Trade. He is chairman of UBS Global Asset Management (Canada) Co. and a non-executive director of Manufacturers Life Insurance Company.

Table of Contents

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

The remuneration committee s reward policy reflects its aim to align executive directors remuneration with shareholders interests and to engage world-class executive talent for the benefit of the Group. The main principles of the policy are:

- Total rewards should be set at appropriate levels to reflect the competitive global market in which BP operates.
- The majority of the total reward should be linked to the achievement of demanding performance targets.
- Executive directors incentives should be aligned with the interests of ordinary shareholders. This is achieved through setting performance targets that take account of measures of shareholders interests and through the committee s policy that each executive director should hold a significant shareholding in the Company, equivalent in value to five times the director s base salary.
- The performance targets in the Executive Directors Incentive Plan (EDIP) should encompass demanding comparisons of BP s shareholder returns and earnings with those of other companies in its own industry and in the broader marketplace.
- The wider scene, including pay and employment conditions elsewhere in the Group, should be taken into account, especially when determining annual salary increases.

The Company s existing policy on executive directors remuneration will remain in place for 2004. The committee is conducting a comprehensive review of its policies in the course of 2004 prior to the expiry of the current EDIP in April 2005. This review will take into account changes in BP s business environment and its strategy. New policies will be described in the next remuneration report for shareholder approval and specific shareholder authorization will be sought for any new long-term share incentive plans. All statements in this report in relation to remuneration policy for years after 2004 should be read in this light.

Elements of Remuneration

The executive directors total remuneration consists of salary, annual bonus, long-term incentives, pensions and other benefits. This reward structure is regularly reviewed by the committee to ensure that it is achieving its objectives. In 2004, over three-quarters of executive directors potential direct remuneration will again be performance-related.

Salary

Each executive director receives a fixed sum payable monthly in cash. The committee reviews salaries annually in line with global markets. In doing so the committee considers appropriate comparator groups in both Europe and the US, which are defined and analyzed by external remuneration advisers engaged independently by the committee.

Table of Contents

Annual Bonus

Each executive director is eligible to participate in an annual performance-based bonus scheme. The remuneration committee reviews and sets bonus targets and levels of eligibility annually. The target level is 100% of base salary (except for Lord Browne, for whom, as group chief executive, it is considered appropriate to have a target of 110%). There is a stretch level of 150% of base salary for substantially exceeding targets. Outstanding performance may be recognized by bonus payments in excess of the stretch level at the discretion of the remuneration committee. Executive directors annual bonus awards for 2004 will be based on a mix of demanding financial targets relating to the Company s annual plan and leadership objectives established at the beginning of the year. In addition to stretching milestones and long-run metrics to track the enactment of strategy, they include areas such as people, safety, environment and organization.

Long-term Incentives

Long-term incentives are provided under the EDIP, which was approved by shareholders in April 2000. It has three elements: a share element, a share option element and a cash element. Each executive director participates in this plan. The committee s policy, subject to unforeseen circumstances, is that this should continue until the plan expires or is renewed in April 2005.

The performance conditions in the share element and share option elements of the EDIP were selected to ensure that executive directors long-term remuneration under the EDIP is appropriately balanced between elements testing BP s performance against that of competitors in the oil industry and elements testing BP s performance against that of leading global companies.

The committee s policy is that each executive director should hold shares equivalent in value to five times the director s base salary within five years of being appointed an executive director. As is reflected in the table of Directors interests on page 142, Lord Browne, Mr Olver and Dr Grote all have holdings in excess of the guidelines. The recent appointees are expected to attain this level within five years of their appointments. 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 share element permits the remuneration committee to grant performance units to executive directors. These are notional units that give the directors the right to be considered for an award of shares (without payment by the directors) at the end of a three-year performance period if demanding performance conditions are met. The committee determines the number of units to be awarded each year. The maximum value that may be granted in any one year will not normally exceed twice the base salary. A maximum of two shares may be awarded for each unit. Shares awarded are then held in trust for three years before they are released to the individual. This gives the executive directors a six-year incentive structure. Shares will only be released at the end of the retention period if the company s minimum shareholding guidelines have been met.

The share element compares BP s performance against the oil and gas sector over three years on a rolling basis. This is assessed in terms of a three year total shareholder return against the market (SHRAM), return on average capital employed (ROACE) and earnings per share growth, based on profit excluding the goodwill and fixed asset valuation adjustment consequent upon the Atlantic Richfield and Burmah Castrol acquisitions and inventory holding gains and losses, adjusted for special items (EPS). SHRAM is the primary measure, accounting for nearly two-thirds of the potential total award. 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.

Table of Contents

For the 2001-2003 plan, BP s three-year SHRAM was measured against the other oil majors: ExxonMobil, Shell, TotalFinaElf and ChevronTexaco, ENI and Repsol. Owing to the reduced number of oil majors, for the 2002-2004, 2003-2005 and 2004-2006 plans BP s three-year 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 for all the plans since 2002 are measured against ExxonMobil, Shell, TotalFinaElf and ChevronTexaco.

The committee reviews and approves annually the performance measures and the comparator companies.

Share Option Element

The share option element of the EDIP is designed to reflect BP s performance relative to a wider selection of global companies. It has a disclosed three-year pre-grant performance requirement that differentiates it from traditional share option schemes. Under this element, options may be granted to executive directors at an exercise price no lower than the market value (as determined in accordance with the plan rules) of a share at the date the option is granted. Reflecting the pre-grant performance requirement, options vest over three years after grant (one-third each after one, two and three years respectively). They have a life of seven years after grant.

In accordance with the framework approved by shareholders in 2000, it is the committee s policy to continue to exercise its judgement to decide the number of options to be granted to each executive director, taking into account BP s total shareholder return (TSR) compared with the TSR for the FTSE Global 100 group of companies over the three years preceding the grant. The committee will not grant options in any year unless the criteria for an award of shares under the share element have been met. These methods of calculation were chosen to enable the committee to take into account not only the TSR position but also the underlying health of the business and the competitive marketplace.

The value of the grants is designed to reflect global market practice for executive pay. Following grant, the options are not subject to any performance conditions. The remuneration committee has favoured this approach for two main reasons. First, it has the effect of treating share options as a reward both for past performance (because BP s ranking within a comparator group will have been taken into account in determining the number of shares under option) and as an incentive for future performance (because the participant s gain under the option will depend on share price growth after the grant under the option). Second, BP operates internationally and the application of a performance condition after grant is not a feature of option schemes operated by major international companies based outside the UK. The use of options and the types of conditions to be attached to them will be considered by the committee as part of the more general review that is being conducted prior to the expiry of the current plan in 2005.

Cash Element

The cash element allows the remuneration committee to grant cash rather than share-based incentives in exceptional circumstances. This element was not used in 2003 and the committee has no present intention to use it in 2004.

Pensions

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

Table of Contents

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.

2003 Remuneration for Executive Directors

Amounts shown are in the currency received by executive directors. For information, the average exchange rate for 2003 was £1=$1.63. Annual bonus is shown in the year it was earned. Share option grants in 2003 were maintained at the same level as in 2002.

	Annual remuneration					Long term Performance Plan (LTPP)				Grants under EDIP	
						2001-2003 LTPP (awarded in Feb 2004)		2000-2002 LTPP (awarded in Feb 2003)		2003-2005 share element (granted in Feb 2003)	Share option element (granted in Feb 2003)
Summary of 2003 remuneration	Salary 000	2003 annual performance bonus 000	Other benefits 000	2003 total 000	2002 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	£ 1,316	£ 1,882	£ 79	£ 3,277	£ 3,031	352,750	£ 1,455	224,000	£ 887	632,512	1,348,032
Dr D C Allen(f)	£ 367	£ 459	£ 2	£ 828		62,518	£ 258			197,044	220,000
Dr B E Grote	$ 770	$ 1,001	$ 179(g)	$ 1,950	$ 1,871	131,750	$ 1,053	68,000	$ 449	233,638	349,038
Dr A B Hayward(f)	£ 367	£ 459	£ 3	£ 829		54,825	£ 226			197,044	220,000
J A Manzoni(f)	£ 367	£ 477	£ 34	£ 878		51,170	£ 211			197,044	220,000
R L Olver	£ 570	£ 741	£ 43	£ 1,354	£ 1,203	144,500	£ 596	117,600	£ 466	274,138	370,956
Directors who left the board in 2003											
R F Chase(h)	£ 231	£ 295	£ 30	£ 556	£ 1,440	174,250	£ 719	139,200	£ 551		

(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 2007 when they are released to the individual.

(b) Based on the closing mid-market price of BP shares on February 12, 2004 (£4.135 per share) or the cost of acquiring ADSs ($47.964 per ADS).

(c) Based on the closing mid-market price on date of award (£3.96 per share/$39.62 per ADS).

(d) Performance units granted under the 2003-2005 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 2003 have a grant price of £3.88 per share. Dr Grote holds options over ADSs; the above numbers reflect calculated equivalents.

(f) Reflects remuneration received since appointment as executive director on February 1, 2003.

(g) Includes resettlement allowances for Dr Grote of $300,000 and $175,000 in 2002 and 2003 respectively.

(h) Amounts for Mr Chase reflect the period until his retirement in May 2003.

Table of Contents

Salary

Base salaries for Lord Browne, Mr Olver and Dr Grote were increased by 5% per annum with effect from July 1, 2003, following a review of appropriate comparator groups. Apart from the 5% promotional increases for Mr Olver and Dr Grote on their appointments to deputy group chief executive and chief financial officer respectively, the three directors had received no salary increases since January 2002. Dr Allen, Dr Hayward and Mr Manzoni received no salary increases since their appointments to the board in February 2003.

Annual Bonus

The annual bonus awards for 2003 were based on a mix of financial targets and leadership objectives established at the beginning of the year. Assessment of all the results produced an award of around 85% of stretch level (stretch level is 150% of base salary). All calculations in relation to the annual bonus have been reviewed by the auditors.

Past Directors

Following Dr Buchanan s retirement from the BP p.l.c. board on November 21, 2002, he remained as an employee until his normal retirement date of June 8, 2003. During that period he received a pro rata normal salary of £227,000 and a pro rata bonus of £289,425.

Following Mr Chase s retirement in May 2003, he was engaged as a consultant to BP in relation to the TNK-BP transaction. Under the consultancy agreement, he receives $50,000 gross per month plus expenses. This consultancy ended in May 2004.

On July 21, 2003, Mr Chase was appointed as a BP-nominated director of TNK-BP Limited, a joint-venture company owned 50% by BP. During 2003, he received emoluments of $120,000 from TNK-BP Limited.

Long-term awards for both former directors are in accordance with scheme rules as outlined in the table on page 137.

Long-term Performance-based Components

Long Term Performance Plans (LTPPs) and Share Element of EDIP

Under the LTPPs and the share element of the EDIP, performance units are granted at the beginning of the period and converted into an award of shares at the end of the three-year period, depending on performance. There is a maximum of two shares per performance unit.

Since the adoption of the EDIP in April 2000, the executive directors have ceased to be eligible for grants under the BP share option plan and the LTPPs. However, they are not required to relinquish rights under those plans that had already been granted prior to their appointments as executive directors (including performance units under the LTPPs that have yet to mature into share awards). Dr Allen, Dr Hayward and Mr Manzoni therefore have rights under the 2000-2002, 2001-2003 and 2002-2004 LTPPs.

For the 2001-2003 share element of the EDIP and the LTPP, BP s performance was assessed in terms of SHRAM, ROACE and pro forma EPS growth each relative to that of ExxonMobil, Shell, Total, ChevronTexaco, ENI and Repsol.

BP s SHRAM came in at sixth place among the comparator group, fourth place on EPS (as defined on page 133) growth and first place on ROACE.

Table of Contents

Based on a performance assessment of 85 points out of 200, the remuneration committee made awards of shares to executive directors as shown in the 2001-2003 lines of the table below.

The following table summarizes the LTPPs and share elements of the executive directors remuneration for 2003.

	LTPP/Share element interests						Interests vested		
			Market price of each share at date of grant of performance units	Performance Units (b)					
	Performance period (a)	Date of grant of performance units	£	At Jan 1 2003	Granted 2003	At Dec 31, 2003	Number of ordinary shares awarded (c)	Share award date	Market price of each share at share award date £
The Lord Browne of Madingley									
	2000-2002	Feb 23, 2000	4.59	280,000			224,000	Feb 17, 2003	3.96
	2001-2003	Feb 19, 2001	5.80	415,000		415,000	352,750	Feb 12, 2004	4.14
	2002-2004	Feb 18, 2002	5.73	475,556		475,556			
	2003-2005	Feb 17, 2003	3.96		632,512	632,512			
Dr B E Grote									
	2000-2002	Feb 23, 2000	4.59	85,000			68,000	Feb 17, 2003	3.96
	2001-2003	Feb 19, 2001	5.80	155,000		155,000	131,750	Feb 12, 2004	4.14
	2002-2004	Feb 18, 2002	5.73	182,613		182,613			
	2003-2005	Feb 17, 2003	3.96		233,638	233,638			
R L Olver									
	2000-2002	Feb 23, 2000	4.59	147,000			117,600	Feb 17, 2003	3.96
	2001-2003	Feb 19, 2001	5.80	170,000		170,000	144,500	Feb 12, 2004	4.14
	2002-2004	Feb 18, 2002	5.73	196,296		196,296			
	2003-2005	Feb 17, 2003	3.96		274,138	274,138			
Directors appointed to the board in 2003									
Dr D C Allen									
	2000-2002	Feb 10, 2000	4.53	65,000 (e)			52,000	Feb 17, 2003	3.96
	2001-2003	Mar 12, 2001	5.88	73,550 (e)		73,500	62,518	Feb 12, 2004	4.14
	2002-2004	Mar 6, 2002	5.99	80,000 (e)		80,000			
	2003-2005	Feb 17, 2003	3.96		197,044	197,044			
Dr A B Hayward									
	2000-2002	Feb 10, 2000	4.53	50,000 (e)			40,000	Feb 17, 2003	3.96
	2001-2003	Mar 12, 2001	5.88	64,500 (e)		64,500	54,825	Feb 12, 2004	4.14
	2002-2004	Mar 6, 2002	5.99	73,500 (e)		73,500			
	2003-2005	Feb 17, 2003	3.96		197,044	197,044			
J A Manzoni									
	2000-2002	Feb 10, 2000	4.53	50,000 (e)			40,000	Feb 17, 2003	3.96
	2001-2003	Mar 12, 2001	5.88	60,200 (e)		60,200	51,170	Feb 12, 2004	4.14
	2002-2004	Mar 6, 2002	5.99	80,000 (e)		80,000			
	2003-2005	Feb 17, 2003	3.96		197,044	197,044			
Directors who left the board in 2003									
R F Chase	2000-2002	Feb 23, 2000	4.59	174,000			139,200	Feb 17, 2003	3.96
	2001-2003	Feb 19, 2001	5.80	205,000		205,000 (f)	174,250	Feb 12, 2004	4.14
	2002-2004	Feb 18, 2002	5.73	237,037		237,037 (f)			
	2002-2004	Mar 13, 2002	6.17	34,994					

					34,994 (f)			
Former Directors								
Dr J G S Buchanan						319,800 (d)	Feb 12, 2004	
	1998-2000	Feb 5, 1998	4.05	159,900	159,900	123,200	Feb 17, 2003	4.14
	2000-2002	Feb 23, 2000	4.59	154,000				3.96
	2001-2003	Feb 19, 2001	5.80	165,000	165,000	140,250	Feb 12, 2004	4.14
	2002-2004	Feb 18, 2002	5.73	192,593	192,593			
	2002-2004	Mar 13, 2002	6.17	28,433	28,433			
W D Ford	2000-2002	Feb 23, 2000	4.59	132,000		105,600	Feb 17, 2003	3.96
	2001-2003	Feb 19, 2001	5.80	170,000	170,000	144,500	Feb 12, 2004	4.14
Dr C S Gibson-Smith	2000-2002	Feb 23, 2000	4.59	140,000		112,000	Feb 17, 2003	3.96

137

Table of Contents

(a) For the performance periods 2000-2002, performance units were granted under the LTPPs. Dr Allen, Dr Hayward and Mr Manzoni also continue to have units granted under the 2001-2003 and 2002-2004 LTPPs which were granted prior to their appointments as executive directors. All other units were granted under the EDIP as explained in this item. BP s performance is assessed in terms of a three-year SHRAM against the oil majors. For 1998-2000 this included ExxonMobil, Shell, Total, ChevronTexaco; for 2000-2002 and 2001-2003 this included ExxonMobil, Shell, Total, ChevronTexaco, ENI, Repsol; for 2002-2004 and 2003-2005 it is measured against the FTSE All World Oil & Gas Index. For 2000-2002, 2001-2003 and 2002-2004 plans, performance is also assessed in terms of ROACE and pro forma EPS growth. For 2000-2002 and 2001-2003, they are measured against ExxonMobil, Shell, Total, ChevronTexaco, ENI, Repsol and for 2002-2004 and 2003-2005 against ExxonMobil, Shell, Total, ChevronTexaco. Each performance period ends on December 31 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 or expected to be made at the end of the relevant performance period based on performance achieved under rules of the plan.

(d) Dr Buchanan elected to defer to 2004 the determination of whether an award should be made for the 1998-2000 performance period. This number does not include accumulated dividends.

(e) On appointment to the board of BP p.l.c. on February 1, 2003.

(f) On leaving the board of BP p.l.c. on April 23, 2003.

Table of Contents

Share Options

The table below represents the interests of executive directors in options over ordinary shares during 2003.

	Option type	At Jan 1, 2003	Granted	Exercised	At Dec 31, 2003	Option price	Market price at date of exercise	Date from which first exercisable	Expiry date
The Lord Browne of Madingley	SAYE	3,661(a)				£ 4.52		Sept 1, 07	Feb 28, 08
	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
Dr B E Grote (b)	SAR	40,000		40,000		$ 13.63	$ 39.20	Mar 23, 96	Mar 23, 03
	SAR	40,800			40,800	$ 16.63		Mar 25, 97	Mar 25, 04
	SAR	35,600			35,600	$ 19.16		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
R L Olver	SAYE	2,386		2,386		£ 2.89	£ 3.89	Sept 1, 02	Feb 28, 03
	SAYE	1,137(a)				£ 5.11		Sept 1, 04	Feb 28, 05
	SAYE	840(a)				£ 4.52		Sept 1, 05	Feb 28, 06
	SAYE		2,642		2,642	£ 3.50		Sept 1, 06	Feb 28, 07
	EDIP	71,847			71,847	£ 5.99		May 15, 01	May 15, 07
	EDIP	260,319			260,319	£ 5.67		Feb 19, 02	Feb 19, 08
	EDIP	370,956			370,956	£ 5.72		Feb 18, 03	Feb 18, 09
	EDIP		370,956		370,956	£ 3.88		Feb 17, 04	Feb 17, 10
Directors appointed to the board in 2003									
Dr D C Allen	EXEC	33,600 (c)		33,600		£ 1.50	£ 4.15	Mar 23, 96	Mar 23, 03
	EXEC	37,000 (c)			37,000	£ 5.99		May 15, 03	May 15, 10
	EXEC	87,950 (c)			87,950	£ 5.67		Feb 23, 04	Feb 23, 11
	EXEC	175,000 (c)			175,000	£ 5.72		Feb 18, 05	Feb 18, 12
	EDIP		220,000		220,000	£ 3.88		Feb 17, 04	Feb 17, 10
Dr A B Hayward	SAYE	3,302(c)			3,302	£ 5.11		Sept 1, 06	Feb 28, 07
	EXEC	34,000 (c)			34,000	£ 5.99		May 15, 03	May 15, 10
	EXEC	77,400 (c)			77,400	£ 5.67		Feb 23, 04	Feb 23, 11
	EXEC	160,000 (c)			160,000	£ 5.72		Feb 18, 05	Feb 18, 12
	EDIP		220,000		220,000	£ 3.88		Feb 17, 04	Feb 17, 10

J A Manzoni		2,600(c)		2,600		£ 3.72	£ 4.33		
		750(c)				£ 4.50			
	SAYE	878(c)				£ 4.52		Sept 1, 03	Feb 28, 04
	SAYE				750	£ 3.50		Sept 1, 04	Feb 28, 05
	SAYE		2,548		878			Sept 1, 07	Feb 28, 08
	SAYE	12,000 (c)			2,548	£ 2.04		Sept 1, 08	Feb 28, 09
	EXEC	34,000 (c)			12,000	£ 5.99		Feb 28, 98	Feb 28, 05
	EXEC				34,000			May 15, 03	May 15, 10
	EXEC	72,250 (c)			72,250	£ 5.67		Feb 23, 04	Feb 23, 11
	EXEC	175,000 (c)			175,000	£ 5.72		Feb 18, 05	Feb 18, 12
	EDIP		220,000		220,000	£ 3.88		Feb 17, 04	Feb 17, 10

Director who left the board in 2003

R F Chase	SAYE	3,388			3,388(d)	£ 4.98		Sept 1, 05	Feb 28, 06
	EDIP	85,215			85,215 (d)	£ 5.99		May 15, 01	May 15, 07
	EDIP	312,171			312,171 (d)	£ 5.67		Feb 19, 02	Feb 19, 08

Table of Contents

The closing market prices of an ordinary share and of an ADS on December 31, 2003 were £4.53 and $49.35 respectively. During 2003, the highest market prices were £4.55 and $49.35 respectively, and the lowest market prices were £3.57 and $35.37 respectively.

EDIP	Executive Directors Incentive Plan adopted by shareholders in April 2000 as described in this item. The awards are 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 individual.
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) Options surrendered on July 3, 2003 for nil cash consideration.

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

(c) On appointment to the board of BP p.l.c. on February 1, 2003.

(d) On leaving the board of BP p.l.c. on April 23, 2003.

Table of Contents

Pensions

In the table below, amounts are shown in the currency received. For information, the average exchange rate for 2003 was £1 = $1.63. Lord Browne, Dr Allen, Dr Hayward, Mr Manzoni and Mr Olver accrued pension benefits in pounds sterling (the currency of payment). Similarly, Dr Grote accrued pension benefits in US dollars.

	Service at Dec 31, 2003	Accrued pension entitlement at Dec 31, 2003	Additional pension earned during the year ended Dec 31, 2003	Transfer value of accrued benefit at Dec 31, 2002 (a) A	Transfer value of accrued benefit at Dec 31, 2003 (a) B	Amount of B-A less contributions made by the director in 2003
				(thousand)		
The Lord Browne of Madingley (UK)	37 years	£ 899	£ 43	£ 12,762	£ 13,921	£ 1,159
Dr D C Allen (UK)	25 years	£ 168	£ 41	£ 1,522	£ 2,089	£ 567
Dr B E Grote (US)	24 years	$ 371	$ 102	$ 3,493	$ 4,814	$ 1,321
Dr A B Hayward (UK)	22 years	£ 170	£ 53	£ 1,302	£ 1,967	£ 665
J A Manzoni (UK)	20 years	£ 135	£ 34	£ 1,007	£ 1,395	£ 388
R L Olver (UK)	30 years	£ 390	£ 36	£ 5,473	£ 6,271	£ 798
Director who left the board in 2003						
R F Chase (UK)(b)	39 years	£ 427		£ 7,766	£ 7,919	£ 153

(a) Transfer values have been calculated in accordance with version 8.1 of guidance note GN11 issued by the actuarial profession.

(b) Mr Chase retired on May 11, 2003 and elected to take a lump sum of £1,124,178 in lieu of part of his entitlement. The figures in the table include the allowance for this lump sum. Mr Chase, in addition, received a superannuation payment of £640,000.

UK Directors

UK directors are members of the BP Pension Scheme. The scheme offers Inland Revenue-approved retirement benefits based on final salary. The BP Pension scheme forms the principal section of the BP Pension Fund, which has been set up under a trust deed. Company contributions to the fund are made on the advice of the actuary appointed by the trustee.

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 integrated with state pension benefits.

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

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

Directors appointed prior to 2003 accrue pension on a non-contributory basis at the enhanced rate of 2/60ths of their final salary for each year of service as executive directors (up to the same two-thirds limit). None of the directors is affected by the pensionable earnings cap.

Table of Contents

In accordance with the Company s long-standing practice for executive directors who retire from BP on or after age 55 having accrued at least 30 years service, Mr Chase received from the Company an ex-gratia lump-sum superannuation payment equal to one year s base salary following his retirement. Lord Browne remains eligible for consideration for such a payment. In the case of these individuals, all matters relating to such superannuation payments are considered by the remuneration committee. Any such payments are additional to their 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 recently announced important proposals on pensions, the impact of which will be reviewed by the committee in 2004.

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 July 1, 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 2003 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 December 31, 2003	At January 1, 2003 or on appointment	Change from December 31, 2003 to June 23, 2004
Current directors			

Dr D C Allen	371,365 (a)	306,565 (a)(b)	36,886
The Lord Browne of Madingley	1,816,054 (c)	1,681,652 (c)	208,122
Dr B E Grote	788,313 (d)	722,562 (d)	77,736
Dr A B Hayward	121,692	92,465 (b)	80,875
J A Manzoni	127,821	95,817 (b)	64,339
R L Olver	798,326	738,563	86,011

	At retirement	At January 1, 2003
Director who left the board in 2003		
R F Chase	902,817 (e)	810,826

(a) Includes 25,368 shares held as ADSs.

(b) At appointment on February 1, 2003.

Table of Contents

(c) Includes 50,368 shares held as ADSs throughout 2003.

(d) Held as ADSs.

(e) On leaving the board on April 23, 2003.

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 BP QUEST Company Limited and 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.

Service Contracts

The committee s policy on executive directors service contracts is for them to contain a maximum notice period of one year. This policy has now been fully implemented.

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. A large proportion of each executive director s total remuneration is linked to performance and therefore will not be payable to the extent that the relevant targets are not met.

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 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.

Table of Contents

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. At the 2004 AGM, shareholders approved an amendment to the Articles so that all directors will stand for re-election at the first meeting following their appointment and subsequently annually, rather than the former practice of standing for re-election at intervals of no more than three years.

Non-Executive Directors Annual Fee Structure

The Company s Articles provide that the remuneration paid to non-executive directors is determined by the board within limits set by shareholders. Fees payable to non-executive directors were last reviewed during 2002. All fees are fixed and paid in pounds sterling. For conformity these are also reported in US dollars.

	$ (a)	£
	(thousands)	
Chairman	636	390 (b)
Deputy chairman	139	85 (c)
Board member	106	65
Committee chairmanship fee	24	15
Transatlantic attendance allowance (d)	8	5

(a) Sterling payments converted at the average 2003 exchange rate of £1 = $1.63.

(b) The chairman is not eligible for committee chairmanship fees or transatlantic attendance allowance but has the use of a fully maintained office and a chauffeured car for company business.

(c) The deputy chairman receives a £20,000 increment on top of the standard board fee. In addition, the deputy chairman is eligible for committee chairmanship fees and the transatlantic attendance allowance. The deputy chairman is currently chairman of the Audit Committee.

(d) This allowance is payable to non-executive directors for each meeting for which they undertake transatlantic travel for the purpose of attending a board meeting or board committee meeting.

Table of Contents

Remuneration of Non-Executive Directors	2003		2002	
	$ (a)	£	$ (b)	£
	(thousands)			
J H Bryan	155	95	120	80
E B Davis, Jr	147	90	120	80
Dr D S Julius	130	80	95	63
C F Knight	155	95	95	63
F A Maljers*	130	80	95	63
Dr W E Massey	179	110	135	90
H M P Miles (c)	130	80	95	63
Sir Robin Nicholson (d)	155	95	110	73
Sir Ian Prosser	187	115	147	98
P D Sutherland	636	390	503	335
M H Wilson	155	95	116	77

(a) Sterling payments converted at the average 2003 exchange rate of £1 = $1.63.

(b) Sterling payments converted at the average 2002 exchange rate of £1 = $1.50.

(c) Also received £600 each year ($900 at 2002 rate; and $978 at 2003 rate) for serving as a director of BP Pension Trustees Limited.

(d) Also received £20,000 each year ($30,000 at 2002 rate; and $32,600 at 2003 rate) for serving as the board s representative on the BP Technology Advisory Council.

* Mr F A Maljers retired from the Board on April 15, 2004.

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. These residual interests require disclosure under the UK directors remuneration report regulations 2002 as interests in a long-term incentive scheme.

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, 2003 and December 31, 2003 (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
F A Maljers	2,906	August 12, 2003 (c)
Dr W E Massey	3,346	April 5, 2008
M H Wilson	3,170	November 4, 2007

145

Table of Contents

(a) No awards were granted or vested and no other awards lapsed during the year.

(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) The award to Mr Maljers vested on April 15, 2004, being the date of the AGM at which he retired from the Board.

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 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 2003.

Non-Executive Directors Shareholdings

Non-Executive Directors interest in BP ordinary shares or calculated equivalents	At December 31, 2003	At January 1, 2003 or on appointment	Change from December 31, 2003 to June 23, 2004
Current directors			
A Burgmans (b)	N/A	10,000	
J H Bryan	158,760 (a)	98,760 (a)	
E B Davis, Jr	65,162 (a)	63,814 (a)	603
Dr D S Julius	15,000	2,000	
C F Knight	95,610 (a)	92,238 (a)	1,508
Dr W E Massey	49,261 (a)	48,232 (a)	461
H M P Miles	22,145	22,145	
Sir Robin Nicholson	3,897	3,758	62
Sir Ian Prosser	16,301	2,826	
P D Sutherland	30,079	7,079	
M H Wilson	60,000 (a)	43,200 (a)	

(a) Held as ADSs.

(b) Mr. A Burgmans was appointed February 5, 2004.

In disclosing the above interests to the Company under the Companies Act 1985, directors did not distinguish their beneficial and non-beneficial interests.

Table of Contents

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 2003 the value of the awards made under the 2000 to 2002 LTPP in respect of the three years covered by that plan. The total remuneration paid during 2003 to all directors and senior management as a group (20 persons) was $28.4 million. Total share options granted during 2003 to all directors and senior management as a group was 3,232,786; these have an option price of £3.88 and expire in 2013. The amount accrued during 2003 to provide pension benefits to all directors and senior management as a group was $8.6 million.

Table of Contents

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 2004)
Dr D C Allen	April 2005	1 year 4 months
The Lord Browne of Madingley	April 2005	12 years 9 months
J H Bryan (b)	April 2005	5 years 6 months
A Burgmans	April 2005	4 months
E B Davis, Jr (b)	April 2005	5 years 6 months
Dr B E Grote	April 2005	3 years 11 months
Dr A B Hayward	April 2005	1 year 4 months
Dr D S Julius	April 2005	2 years 7 months
C F Knight	April 2005	16 years 9 months
J A Manzoni	April 2005	1 year 4 months
Dr W E Massey (b)	April 2005	5 years 6 months
H M P Miles	April 2005	10 years 1 months
Sir Robin Nicholson	April 2005	16 years 9 months
R L Olver	April 2005	6 years 6 months
Sir Ian Prosser	April 2005	7 years 2 months
P D Sutherland	April 2005	8 years 10 months
M H Wilson (b)	April 2005	5 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 Olver will retire from BP on July 1, 2004.

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 Mr Olver, Dr Allen, Dr Hayward and Mr Manzoni 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, 2003, this secondment agreement had an unexpired term of four 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.

Table of Contents

Corporate Governance Statement

BP has long recognized the importance of good governance. The board has adopted and operates within a robust set of governance policies that are designed to place the interests of our shareholders at the heart of all we do. Formulated in 1997, these policies, which use a principles-based approach, anticipated many developments in UK governance practices.

Accountability to Shareholders

The board governance policies emphasize the importance of the relationship between the board and the shareholders, underlining the board s role in representing and promoting the interests of shareholders. The board is accountable to shareholders for the performance and activities of the entire group (including, for example, the system of internal control and the review of its effectiveness). The board is accountable in a variety of ways. Directors are required to stand for re-election each year at the AGM. New directors are subject to election at the first opportunity following their appointment. Names submitted to shareholders for re-election are accompanied by detailed biographies.

The board is required to be proactive in obtaining an understanding of shareholder preferences and to evaluate systematically the economic, social, environmental and ethical matters that may influence or affect the interests of its shareholders. In carrying out its work, the board has to exercise judgement on how best to further the interests of shareholders. The board seeks to do so by maximizing the expected value of the shareholders interests in the company, not by eliminating the possibility of any adverse outcomes for shareholders. The board considers reports on contacts with shareholders so it can promote and represent shareholder interests through its policy-making and monitoring functions and its active consideration of group strategy. As a result, shareholder interests are embedded in the goals established by the board for the company.

Shareholder Communication, Meetings and Voting

The board makes use of a number of formal communication channels to account to shareholders for the performance of the company. These include the Annual Report and Accounts, the Annual Review, the Annual Report on Form 20-F, quarterly announcements made through stock exchanges on which BP shares are listed, as well as through the AGM. Presentations given at appropriate intervals to representatives of the investment community are available simultaneously to all shareholders, by live internet broadcast or open conference call. Less formal processes include the chairman s contact with institutional shareholders, which is supported by the dialogue with shareholders concerning the governance and operation of the group maintained by the company secretary s office.

Given the size and geographical diversity of BP s shareholder base, the opportunities for shareholder interaction at the AGM are limited. However, the chairman and all board committee chairmen were present at the 2003 and 2004 AGMs to answer questions from shareholders. All votes, whether by proxy or in person, at shareholder meetings are counted since votes on all matters, except procedural issues, are taken by way of a poll. BP has also pioneered the use of electronic communications to facilitate the exercise of shareholder control rights.

The Work of the Board in Governance

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.

Table of Contents

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 (as defined therein) and delegate all aspects of the relationship between the board and the group chief executive to the non-executive directors.

To discharge its governance function in the most effective manner, the board has laid down rules for its own activities in a board process policy that covers the conduct of members at meetings; the cycle of board activities and the setting of agendas; the provision of information to the board; board officers and their roles; board committees - their tasks and composition; qualifications for board membership and the process of the nomination committee; the 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, which includes training of directors, is placed on the chairman.

At its heart, the board process policy recognizes that the board s capacity, as a group, is limited. The board therefore reserves to itself the making of broad policy decisions, delegating more detailed considerations involved in meeting its stated requirements either to board committees and officers (in the case of its own processes) or to the group chief executive (in the case of the management of the company s business activity). The board s role is to set general policy and to monitor its implementation by the group chief executive. To this end, the board executive linkage policy sets out how the board delegates authority to the group chief executive and the extent to that authority. In its goals policy, the board states the long-term outcome it expects the group chief executive to deliver. The restrictions on the manner in which the group chief executive may achieve the required results are set out in the executive limitations policy, which addresses ethics, health, safety, the environment, financial distress, internal control, risk preferences, treatment of employees and political considerations.

The group chief executive explains how he intends to deliver the required outcome in annual and medium-term plans, which also respond to the group s comprehensive assessment of 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 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 group chief executive is obliged through dialogue and systematic review to discuss with the board all material matters currently or prospectively affecting the company and its performance and all strategic projects or developments. This key dialogue specifically includes any materially under-performing business activities and actions that breach the executive limitations policy. It also includes social, environmental and ethical considerations. 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.

Board Committees

The board process policy allocates the tasks of monitoring executive actions and assessing performance to the following committees:

Audit Committee - to monitor all reporting, accounting, financial and control aspects of the executive management s activities.

Ethics and Environment Assurance Committee - to monitor the non-financial aspects of the executive management s activities.

Table of Contents

Remuneration Committee - to determine performance contracts, targets and the structure of the rewards for the group chief executive and the executive directors and to monitor the policies being applied in remunerating other senior executives.

These tasks prescribe the authority and the role of the committees. Reports for each of these committees for 2003 appear on pages 153-154.

The board process policy establishes two further committees, whose tasks are focused on assessing the overall performance of the group chief executive, the structure and effectiveness of the business organization (including the board) and succession planning for both executive and non-executive directors. The chairman s committee comprises all the non-executive directors. It considers broad issues of governance, including matters referred to it for an opinion from any other board committee. The nomination committee, formally tasked with the identification and evaluation of candidates for appointment or reappointment as director or company secretary, has been established with a fluid membership comprising the chairman, group chief executive and three non-executive directors drawn from the body of non-executives from time to time. External search consultants are retained to propose candidates for appointment to the board, with requisite skills and experience identified in the results of the board s annual evaluation processes.

During 2003, discussions on board succession planning for both executive and non-executive director appointments (and the appointment of the new company secretary) took place in the wider forum of the chairman s committee, so as to allow the broadest possible non-executive director participation (see section on Board succession planning). The board has determined that from now on the nomination committee will comprise the chairman, the senior independent director and the chairmen of each of the audit, the ethics and environment assurance and the remuneration committees. The group chief executive will be invited to attend meetings and participate in discussions when appropriate.

Board Meetings and Board Attendance

In addition to the 2003 AGM (which all directors attended), the board met eight times during 2003, five times in the UK and three times in the US. Two of these meetings were two-day strategy discussions.

All directors attended all board meetings, except that Mr Davis, Mr Maljers, Dr Massey and Sir Robin Nicolson were absent from one board meeting each. However, whenever necessary, absent board members joined meetings by video-link for relevant items.

The Chairman, Senior Independent Director and Company Secretary

Between board meetings the chairman has responsibility for ensuring the integrity and effectiveness of the board/executive relationship. The board governance policies require the chairman and deputy chairman to be non-executive directors; throughout 2003 and through June 2004 the posts were held by Mr Sutherland and Sir Ian Prosser respectively. Sir Ian also acts as the senior independent director and is the director whom shareholders may contact if they feel their concerns are not being addressed through normal channels. The company secretary reports to the chairman and is not part of the executive management. The company secretary s office provides support to all the non-executive directors, ensuring that board and board committee processes are demonstrably independent of the executive management of the group.

Board Succession Planning

The board is composed of the chairman, eleven non-executive and six executive directors. A number of current directors are approaching the board s mandatory retirement age for non-executive directors (age 70). To manage the process of board succession without compromising the effectiveness of the board and its committees, the board has agreed the following timetable of non-executive appointments and retirements, subject always to directors continued re-election. Mr Maljers retired from the board at the 2004 AGM, while Mr Knight and Sir Robin Nicolson will retire at the 2005 AGM.

Mr Bryan and Mr Miles will retire at the 2006 AGM and Mr Wilson at the 2007 AGM. Mr Burgmans joined the board in February 2004 as a non-executive director. An additional non-executive director is expected to join the board during 2004, with at least one further new non-executive director to be appointed before the 2005 AGM. Further non-executive directors will be appointed over the coming years.

In making appointments as non-executive directors, the opportunity is taken to ensure a broad range of skill-sets, in particular those skills identified following consideration of the board and board committee evaluation processes (see page 151).

The number of directors will therefore increase in the short term. While this will create a large board by UK standards, BP believes that this is necessary to allow not only sufficient executive director representation to cover the breadth of the group s business activity but also sufficient non-executive representation to reflect the scale and complexity of the company and to staff the board committees. A board of this size will also allow necessary succession planning for key roles.

Independence

The qualification for board membership includes a requirement that all non-executive directors be free from any relationship with the executive management of the company that could materially interfere with the exercise of their independent judgement. In the board s view, all non-executive directors fulfil this requirement. It has therefore determined all twelve to be independent directors.

Two current directors, Mr Knight and Sir Robin Nicolson, were appointed to the BP board in 1987. Mr Miles was appointed in 1994. The length of their respective service on the board exceeds the nine years referred to in the new UK Combined Code, which provides that an explanation be made to shareholders concerning their continuing independence. The board considers that the integrity and independence of character of these directors are beyond doubt, while their experience and long-term perspective on BP s business during its recent period of growth provide a valuable and unique contribution to the board. Both Mr Knight and Sir Robin will retire at next year s AGM, having seen through ongoing work in the remuneration committee as outlined in the directors remuneration report. Sir Robin retired and was re-elected at the 2004 AGM. Mr Miles will continue until 2006.

Those directors who joined the BP board in 1998 after service on the board of Amoco Corporation are considered independent since the most senior executive management of BP comprises individuals who were not previously Amoco employees. Moreover, the scope and scale of the BP group 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) and that, where necessary, appropriate processes are in place to manage any possible conflict of interest.

Sir Robin Nicolson received fees during 2003 for representing the board on the BP Technology Advisory Council. Since these fees relate to board representation, they do not compromise Sir Robin s independence. Mr Miles received fees for his service as a director of BP Pension Trustees Limited (BPPT) during 2003. These fees, payable to all non-employed BPPT directors, are modest in size and as such are not considered to affect Mr Miles independence. However, he has agreed that from now on no such fees should be payable in respect of his service as a director of BPPT. Full details of these fees are disclosed on page 145.

Any significant ways in which our corporate governance practices, including determination of independence, differ from those followed by US companies under New York Stock Exchange listing standards are disclosed on our website at www.bp.com.

Induction, Training and Evaluation

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, and the powers delegated to those committees, the board s governance policies and practices, and the latest financial information about the Group. The training and induction processes for directors are evolving to take into account the development of the Group and applicable governance standards. Throughout their period in office the directors are updated on BP s business, the environment in which it operates and other matters. With the agreement of the board, executive directors are permitted to take up external board appointments. It is the company s policy that executive directors may retain any fees received in respect of such external appointments.

Directors are advised on appointment of their legal and other duties and obligations as directors of a listed company. The board regularly considers the implications of these duties under BP s board governance policies. The directors address developments in corporate regulation and governance affecting BP and their role as directors, endorsing the approach to be taken by the company.

During 2003, the board continued annual evaluation processes to assess its performance and identify areas in which the effectiveness of the board, its policies or process might be enhanced. Directors completed questionnaires and subsequently met with the chairman to discuss matters identified. The results of the evaluation process were presented to the board and the matters identified addressed. Board committees have begun to conduct more structured evaluation of their performance annually, leading to refinements in their processes, composition and work programmes.

Audit Committee Report

The committee, chaired by Sir Ian Prosser, met nine times during 2003. Members of the audit committee (all independent non-executive directors refer to Independence section on page 152) are listed on page 128. The external auditors lead partner and the BP general auditor (head of internal audit) attend each meeting at the request of the committee chairman. Five audit committee meetings were fully attended. Mr Bryan, Mr Davis, Mr Miles and Mr Wilson were each unable to attend one meeting. The board considers that the membership of the audit committee as a whole has sufficient recent and relevant financial experience to discharge its functions.

The audit committee s tasks (outlined on page 150) are considered by the committee to be broader than those envisaged under the new UK Combined Code Provision C.3.3. The committee is satisfied that it addresses each of those matters identified as properly falling within an audit committee s purview.

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. All annual and quarterly financial reports are reviewed by the committee through a process of engaging with the representatives of executive management (specifically the chief financial officer, the group chief accounting officer and the group controller) as well as with the external and internal auditors. The committee discusses significant accounting policies, estimates and judgements applied in the preparation of these reports and obtains assurance from the external auditors of their support or any area of difference. The committee gives its recommendation to the board concerning the adoption and publication of all financial reports to shareholders.

The committee keeps under review the scope and results of external 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 and, in accordance with its policy on non-audit services provided by the auditors, the committee reviews and approves the award of any such work. This is limited to defined audit-related work and tax services that fall within specific categories.

The committee considered the appointment of the auditor for the group for 2004 and recommended to the board that Ernst & Young LLP be proposed for reappointment, having noted with satisfaction the scope and results of their audit work, their objectivity and independence, and having received due assurance regarding Ernst & Young s objectivity, independence and viability in the year ahead. The board duly endorsed the committee s recommendation. The appointment of the auditor for 2004 was duly confirmed by shareholders at the 2004 AGM.

Aside from its review of all financial reports and monitoring of external audit work, the committee considers the internal audit programme and reviews matters identified in it. The committee also receives regular reports on development in financial reporting practices so as to keep abreast of current thinking on accounting policies and standards.

During the course of the year the committee considered a number of matters including internal financial control and risk management systems within three major business segments, the integration of Veba in Europe, the company s risk management processes in Indonesia and the monitoring of international accounting developments.

The committee has also adopted group-wide procedures to ensure that it is alerted to issues of fraud or matters of concern raised related to the finances and financial accounting policies of the group.

Ethics and Environment Assurance Committee Report

The committee, chaired by Dr Massey, met four times during 2003. Members of the ethics and environment assurance committee (all independent non-executive directors refer to Independence section on page 152) are listed on page 128. The external auditors lead partner and the BP general auditor (head of internal audit) attend each meeting at the request of the committee chairman. Committee meetings were fully attended, except that Mr Maljers was unable to attend two meetings and Mr Wilson one meeting.

The committee considers matters relating to the executive management s processes to address environmental, social and reputation issues and the systems in place to manage non-financial risks to the group. It receives a report at each meeting from the deputy group chief executive on behalf of the executive management of the Group. During the course of the year, the committee considered a number of specific topics, including environmental remediation, the company s system of certifying adherence by staff to its ethical standards, greenhouse gas emissions and the management of risk in shipping operations. The company also sought and received regular reports on health, safety, security and environment (HSSE) performance and the company s employee concerns programme Open Talk.

Remuneration Committee Report

The committee, chaired by Sir Robin Nicolson, met six times during 2003. Members of the remuneration committee (all independent non-executive directors refer to Independence section on page 152) are listed on page 128. Full details of executive directors remuneration is set out on pages 132-143.

Table of Contents

EMPLOYEES

	UK	Rest of Europe	USA	Rest of World	Total
Number of employees at December 31, 2003					
Exploration and Production	3,000	650	4,850	6,850	15,350
Gas, Power and Renewables	200	800	1,150	1,400	3,550
Refining and Marketing	10,050	17,850	25,700	12,550	66,150
Petrochemicals	2,500	5,950	6,150	1,350	15,950
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	5,500	7,000	16,800
Gas, Power and Renewables	250	1,000	1,500	1,650	4,400
Refining and Marketing	9,950	22,250	28,100	12,000	72,300
Petrochemicals	2,800	5,800	6,650	3,700	18,950
Other businesses and corporate	1,250		1,450	100	2,800
	17,750	29,850	43,200	24,450	115,250
2001					
Exploration and Production	3,700	800	5,550	6,500	16,550
Gas, Power and Renewables	650	650	1,350	1,550	4,200
Refining and Marketing	10,450	15,100	27,800	11,250	64,600
Petrochemicals	3,450	6,250	6,700	5,550	21,950
Other businesses and corporate	1,400		1,350	100	2,850
	19,650	22,800	42,750	24,950	110,150

Employee numbers decreased in 2003, 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 reorganisation of Refining and Marketing operation in Germany. The increase in 2002 was mainly due to the Veba acquisition.

The Company seeks to maintain constructive relationships with labour unions.

Table of Contents

SHARE OWNERSHIP

Directors and Senior Management

As at June 23, 2004 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	408,251
The Lord Browne of Madingley	2,024,176
Dr B E Grote	866,049
Dr A B Hayward	202,567
J A Manzoni	192,160
R L Olver	884,337
J H Bryan	158,760
A Burgmans	10,000
E B Davis, Jr	77,360
Dr D S Julius	15,000
C F Knight	97,118
Dr W E Massey	49,722
H M P Miles	22,145
Sir Robin Nicholson	3,959
Sir Ian Prosser	16,301
P D Sutherland	30,079
M H Wilson	60,000

As at June 23, 2004, 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
Dr B E Grote	1,427,190(a)
Dr A B Hayward	769,702
J A Manzoni	792,426
R L Olver	1,476,720

(a) In addition to the above, Dr Grote holds 110,800 Stock Appreciation Rights (equivalent to 664,800 ordinary shares).

There are no directors or members of senior management who own more than 1% of the ordinary Shares outstanding. At June 23, 2004, all directors and senior managers as a group held interests in 6,203,412 ordinary shares or their calculated equivalent and 13,066,568 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

	2003	2002	2001
Employee share options granted during the year	(options thousands)		
Executive Directors Incentive Plan	2,728	2,068	2,598
BP Share Option Plan	78,109	66,771	58,208
Savings-related schemes	23,922	9,719	7,901
	104,759	78,558	68,707

The exercise prices for BP options granted during the year were £3.88/$6.32 (weighted average price) for Executive Directors Incentive Plan (2,728,026 options); £3.91/$6.38 (weighted average price) for 78,108,230 options granted under the BP Share Option Plan; and £3.50/$5.70 (23,922,346 options) for savings-related and similar plans.

Table of Contents

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 Item 18 Financial Statements Note 36 on page F-58) and the granting of share options as elements of remuneration for executive directors and senior employees.

During 2003, 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 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 business and the competitive market place. 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 2003 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 operated 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 operated 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. Company contributions are initially invested in a fund primarily comprised of BP ADSs but employees may transfer those amounts and may invest their own contributions in more than 200 investment options. The Company s contributions generally vest over a period of three years. Company contributions to savings plans during 2003 were $130 million (2002 $125 million and 2001 $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. The Company provides funding to the ESOP. The assets and liabilities of the ESOP are recognized as assets and liabilities of the Company within the accounts. The ESOP has waived its rights to dividends.

During 2003, the ESOP released 16,892,853 shares (2002 15,332,235 shares and 2001 11,508,754 shares) for the matching share plans. The cost of shares released for these plans has been charged in these accounts. At December 31, 2003 the ESOP held 7,811,544 shares (2002 18,673,675 shares and 2001 34,005,910 shares).

Pursuant to the various BP Group share option schemes, the following options for Ordinary Shares of the Company were outstanding at June 23, 2004:

Options outstanding	Expiry dates of options	Exercise Price per share
(shares)		
549,379,981	2004-2014	$3.95 to $9.97

Further details on share options appear in Item 18   Financial Statements   Note 35 on page F-54.

ITEM 7 MAJOR SHAREHOLDERS AND RELATED PARTY TRANSACTIONS

MAJOR SHAREHOLDERS

At June 23, 2004, 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 6,960,161,404 ordinary shares (31.8% 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 (3.27% 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 664,101,738 ordinary shares (3.04% of the Company s ordinary share capital).

RELATED PARTY TRANSACTIONS

The Group had no material transactions with joint ventures and associated undertakings during the period commencing January 1, 2003 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-77.

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, 2003 to June 23, 2004.

ITEM 8 FINANCIAL INFORMATION

CONSOLIDATED STATEMENTS AND OTHER FINANCIAL INFORMATION

Financial Statements

See Item 18 Financial Statements.

Dividends

The total dividends announced for 2003 were $5,753 million, compared with $5,375 million in 2002 and $4,935 million in 2001. Dividends per share for 2003 were 26.00 cents, compared with 24.00 cents per share in 2002 (an increase of 8.3%) and 22.00 cents per share in 2001 (an increase of 9.1% over 2001). For information on our policy on distributions to shareholders, refer to Item 5 Operating and Financial Review and Prospects Prospects on page 110.

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 do 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 70.

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.

Table of Contents

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 1999, 2000, 2001, 2002 and 2003. These are derived from the Daily Official List of the LSE, and the highest and lowest sales prices of ADSs as reported on the New York Stock Exchange composite tape. The information in this table has been changed to reflect the subdivision of BP ordinary shares on October 4, 1999, whereby each ordinary share of $0.50 was subdivided into two ordinary shares of $0.25.

		Ordinary shares		American Depositary Shares (a)	
		High	Low	High	Low
		(Pence)		(Dollars)	
Year ended December 31,					
1999		643.50	411.00	62.63	40.19
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
Year ended December 31,					
2002:	First quarter	625.00	511.00	53.10	43.84
	Second quarter	625.00	523.50	53.88	47.30
	Third quarter	559.50	418.00	50.86	39.32
	Fourth quarter	458.50	392.50	42.35	36.78
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 (through June 23)	500.50	455.50	54.99	50.75
Month of					
December 2003		454.50	410.00	49.59	42.78
January 2004		454.75	428.25	50.40	47.21
February 2004		433.00	413.50	49.41	46.65
March 2004		457.00	435.00	51.48	47.79
April 2004		499.00	455.50	54.72	50.75
May 2004		500.50	477.75	54.99	51.20
June 2004 (through June 23)		498.00	475.75	54.97	51.93

(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 23, 2004, 1,160,026,901 ADSs (equivalent to 6,960,161,406 ordinary shares or some 31.8% of the total) were outstanding and were held by approximately 168,000 ADR holders. Of these, about 166,500 had registered addresses in the USA at that date. One of the registered holders of ADSs represents some 754,500 underlying holders.

On June 23, 2004 there were approximately 352,000 holders of record of ordinary shares. Of these holders, around 1,400 had registered addresses in the USA and held a total of some 3,455,000 ordinary shares.

Table of Contents

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 Annual General Meeting held on April 15, 2004, shareholders approved an amendment to the Articles of Association such that at each Annual General Meeting held after December 31, 2004, all directors shall retire from office and may offer themselves for re-election.

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

161

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.

Table of Contents

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 Annual General Meeting held on April 15, 2004, shareholders approved an amendment to the Articles of Association such that at each Annual General Meeting 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.

Table of Contents

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 authorised 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.

Table of Contents

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.

Table of Contents

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 and 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 the 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 is 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 are also subject to withholding in an amount equal to the amount of the tax credit. Such US holder therefore will not receive any payment from the UK Inland Revenue in respect of a dividend from the Company and will have no further UK tax to pay in respect of that dividend. Under the Old Treaty,

Table of Contents

special rules apply for determining the tax credit available to a corporation that, either alone or together with one or more associated corporations, controls, directly or indirectly, 10% or more of the Company s voting stock.

Under the New Treaty, a US holder will not be 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 will not be 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 will take effect for United States federal income tax purposes on January 1, 2004. The rules of the Old Treaty remain applicable until these effective dates. A taxpayer may in any case elect to have the Old Treaty apply in its entirety for a period of twelve months after the applicable effective dates of the New Treaty.

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 120-day period beginning 60 days before the ex-dividend date and meets other holding period requirements. Recently the IRS announced that it will permit taxpayers to apply a proposed legislative change to the holding period requirement described in the preceding sentence as if such change were already effective. This legislative technical correction would change the minimum required holding period, retroactive to January 1, 2003, to more than 60 days during the 121-day period beginning 60 days before the ex-dividend date. Dividends paid by the Company with respect to the shares or ADSs will generally be qualified dividend income.

A US holder that is eligible for the benefits of the Old Treaty may include in the gross amount 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 will be creditable against the US holder s United States federal income tax liability, provided the US holder is eligible for the benefits of the Old Treaty and has appropriately filed Internal Revenue Form 8833. Special rules apply in determining the foreign tax credit limitation with respect to dividends that are subject to the maximum 15% tax rate.

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.

In either case, the 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 financial services income , which is treated separately from other types of income for purposes of computing the allowable foreign tax credit.

Table of Contents

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.

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 ADRs 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% where the holder has a holding period of more than 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.

Table of Contents

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 USA 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 USA or to be credited against tax payable in the USA or for tax paid in the USA to be credited against tax payable in the UK, based on priority rules set forth in the Estate Tax Convention.

UK Stamp Duty and Stamp Duty Reserve Tax

The statements below relate to what is understood to be the current practice of the UK Inland Revenue under existing law.

Provided that the instrument of transfer is not executed in the UK and remains at all times outside the UK, and the transfer does not relate to any matter or thing done or to be done in the UK, no UK stamp duty is payable on the acquisition or transfer of ADSs. Neither will an agreement to transfer ADSs in the form of ADRs give rise to a liability to stamp duty reserve tax.

Purchases of 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 450 Fifth Street, NW, 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.

Table of Contents

ITEM 11 QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

BP is exposed to a number of different market risks arising from the Group s normal business activities. Market risk is the possibility that changes in currency exchange rates, interest rates or oil and natural gas prices will adversely affect the value of the Group s financial assets, liabilities or expected future cash flows. The Group has developed policies aimed at managing the volatility inherent in certain of these natural business exposures and in accordance with these policies the Group enters into various transactions using derivative financial and commodity instruments (derivatives). Derivatives are contracts whose value is derived from one or more underlying financial instruments, indices or prices which are defined in the contract. The Group also trades derivatives in conjunction with these risk management activities.

In market risk management and trading, conventional exchange-traded derivative instruments such as futures and options are used, as well as non-exchange-traded instruments such as swaps, over-the-counter options and forward contracts.

Where derivatives constitute a hedge, the Group s exposure to market risk created by the derivative is offset by the opposite exposure arising from the asset, liability or transaction being hedged. By contrast, where derivatives are held for trading purposes, changes in market risk factors give rise to realized and unrealized gains and losses, which are recognized in the current period.

All 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, meeting generally accepted industry practice and reflecting the principles of the Group of Thirty Global Derivatives Study recommendations. A Trading Risk Management Committee has oversight of the quality of internal control in the Group s trading function. Independent control functions monitor compliance with BP s policies. The control framework includes prescribed trading limits that are reviewed regularly by senior management, daily monitoring of risk exposure using value-at-risk principles, marking trading exposures to market and stress testing to assess the exposure to potentially extreme market situations. 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.

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 26 on pages F-9 and F-39.

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 . The Group does not intend to modify its practice under UK GAAP. See Item 18 Financial Statements Note 48 on page F-100 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 chemicals 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, 2003, the total of foreign currency borrowings not swapped into US dollars amounted to $756 million. The principal elements of this are $316 million of borrowings in euros, $107 million in sterling, $103 million in Canadian dollars, $86 million in Trinidad and Tobago dollars and $50 million in Chinese renminbi.

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, 2003 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.

Table of Contents

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							Fair value
	2004	2005	2006	2007	2008	Beyond 2008	Total	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							

(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.

Table of Contents

	Notional amount by expected maturity date						Fair value asset/ (liability)
	2003	2004	2005	2006	2007	Total	
				($ million)			
At December 31, 2002							
Forwards							
Receive sterling/pay US dollars							
Contract amount	2,066	30				2,096	177
Weighted average contractual exchange rate	1.48						
Receive euro/pay US dollars							
Contract amount	(3)	47	14			58	43
Weighted average contractual exchange rate	0.96						
Receive Norwegian krone/pay US dollars							
Contract amount	204	5	2			211	15
Weighted average contractual exchange rate (a)	8.58						
Cylinders							
Receive sterling/pay US dollars							
Purchased call							
Contract amount	859					859	10
Weighted average strike price	1.62						
Sold put							
Contract amount	859					859	(4)
Weighted average strike price	1.52						
Pay euro/receive US dollars							
Sold call							
Contract amount	430					430	(11)
Weighted average strike price	1.05						
Purchased put							
Contract amount	430					430	1
Weighted average strike price	0.92						
Pay euro/receive sterling							
Sold call							
Contract amount	614					614	(3)
Weighted average strike price	£ 0.68						
Purchased put							
Contract amount	614					614	1
Weighted average strike price	£ 0.62						

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, 2003 was 97% of total finance debt outstanding.

Table of Contents

The following table shows, by major currency, the Group s finance debt at December 31, 2003 and 2002 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, 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
At December 31, 2002						
US dollar	7	7	7,818	2	13,287	21,105
Sterling				4	103	103
Other currencies	7	11	317	5	483	800
Total loans			8,135		13,873	22,008

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, 2003. 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, 2004, the Group s 2004 earnings before taxes would decrease by approximately $210 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, 2003 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 short-term 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 conventional oil price-related financial and commodity derivatives available in the oil markets.

The derivative instruments used for hedging purposes do not expose the Group to market risk because the change in their market value is offset by an equal and opposite change in the market value of the asset, liability or transaction being hedged. The values at risk in respect of derivatives held for oil price risk management purposes are shown in isolation in the table below. The items being hedged are not included in the values at risk.

The value-at-risk model used is that discussed under Trading below. Thus the value-at-risk calculation for oil price exposure includes derivative financial instruments such as exchange-traded futures and options, swap agreements and over-the-counter options and derivative commodity instruments (commodity contracts that permit settlement either by delivery of the underlying commodity or in cash) such as forward contracts. The values at risk represent the potential gain or loss in fair values over a 24-hour period with a 99.7% confidence level.

The following table shows values at risk for oil price risk management activities.

	High	Low	Average	December 31
			($ million)	
2003				
Oil price contracts	9	5	7	7
2002				
Oil price contracts	13	11	12	11
2001				
Oil price contracts	11	4	7	7

Natural Gas Price Risk

BP s general policy with respect to natural gas price risk is to manage only a portion of its exposure to price fluctuations. Natural gas swaps, options and futures are used to convert specific sales and purchases contracts from fixed prices to market prices. Swaps are also used to hedge exposure to price differentials between locations.

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.

Table of Contents

At December 31, 2003, in addition to the swaps contracts shown in the table there were options contracts with aggregate notional amounts of $174 million (December 31, 2002 $11 million and December 31, 2001 $1,090 million) and terms of up to one year.

	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

Table of Contents

	Quantity	Contract amount	Fair value		Weighted average price	
			Asset	Liability	Receive	Pay
	(btu trillion)(a)	($ million)	($ million)		($ per mmbtu)(b)	
At December 31, 2002						
Maturing in 2003						
Swaps						
Receive variable/pay fixed	190	734	129	(4)	4.54	3.89
Receive fixed/pay variable	140	529		(108)	3.78	4.56
Receive and pay variable	586	2,633	62	(61)	4.40	4.40
Maturing in 2004						
Swaps						
Receive variable/pay fixed	24	95	8	(1)	4.20	3.87
Receive fixed/pay variable	16	62		(9)	3.76	4.33
Receive and pay variable	181	757	19	(22)	4.06	4.08
Maturing in 2005						
Swaps						
Receive variable/pay fixed	6	25	1		3.91	3.78
Receive fixed/pay variable	1	6			3.74	3.83
Receive and pay variable	115	444	10	(10)	3.77	3.77
Maturing in 2006						
Swaps						
Receive variable/pay fixed	2	7			3.85	3.94
Receive fixed/pay variable		1			4.32	3.85
Receive and pay variable	61	228	1	(3)	3.62	3.70
Maturing in 2007						
Swaps						
Receive variable/pay fixed	2	7			3.91	3.99
Receive fixed/pay variable		1			4.36	3.91
Receive and pay variable	55	204	1	(3)	3.70	3.75
Maturing beyond 2007						
Swaps						
Receive variable/pay fixed	1	5			3.93	4.05
Receive fixed/pay variable	1	5	1		4.85	4.13
Receive and pay variable	119	461	1	(5)	3.81	3.85

(a) British thermal units (btu)

(b) Million british thermal units (mmbtu)

Trading

In conjunction with the risk management activities discussed above, BP also trades interest rate and foreign currency exchange rate derivatives. The Group controls the scale of the trading exposures by using a value-at-risk model with a maximum value-at-risk limit authorized by the board.

In addition to the risk management activities related to equity crude disposal, refinery supply and marketing, BP s supply and trading 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 to manage certain of its exposures to price fluctuations on natural gas and power transactions. These activities are monitored and are subject to maximum value-at-risk limits authorized by the board.

Table of Contents

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 twelve months, together with the correlation of these price movements. The potential movement in fair values is expressed to three standard deviations which is equivalent to a 99.7% confidence level. This means that, in broad terms, one would expect to see an increase or a decrease in fair values greater than the value-at-risk on only one occasion per year if the portfolio were left unchanged.

The Group calculates value-at-risk on all instruments that are held for trading purposes and that therefore give an exposure to market risk. The value-at-risk 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)	
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
2001				
Interest rate trading	1			
Foreign exchange trading	3		1	
Oil price trading	29	10	18	17
Natural gas price trading	21	4	10	9
Power price trading	10	1	4	3

Table of Contents

The following tables show the changes during the year in the net fair value of instruments held for trading purposes for the years 2003 and 2002.

	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, 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
Fair value of contracts at January 1, 2002		(3)	26	12	25
Contracts realized or settled in the year		3	(22)	154	(21)
Fair value of new contracts when entered into during the year					18
Other changes in fair values		12	18	(9)	(3)
Fair value of contracts at December 31, 2002		12	22	157	19

The following tables show the net fair value of contracts held for trading purposes at December 31, 2003 and 2002 analyzed by maturity period and by methodology of fair value estimation.

	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, 2002

	Maturity less than 1 year	Maturity 1-3 years	Maturity 4-5 years	Maturity over 5 years	Total fair value
			($ million)		
Prices actively quoted	115	66	6		187
Prices provided by other external sources	9	3			12
Prices based on models and other valuation methods	11				11
	135	69	6		210

ITEM 12 DESCRIPTION OF SECURITIES OTHER THAN EQUITY SECURITIES

Not applicable

Table of Contents

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.

The Company s management, with the participation of the Company s Group chief executive and chief financial officer, has evaluated the effectiveness of the Company s disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b) as of the end of the period covered by this annual report. Based on that evaluation, the Group chief executive and chief financial officer have concluded that, subject to the limitations noted above, the Company s disclosure controls and procedures are effective to provide reasonable assurance that material information required to be included in the Company s periodic filings under the Exchange Act is made known to them on a timely basis.

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.

Table of Contents

ITEM 16A AUDIT COMMITTEE FINANCIAL EXPERT

The Board has determined that no one member of the audit committee has all the attributes of an audit committee financial expert as defined for purposes of disclosure Item 16A of Form 20-F. The Company does not have an audit committee financial expert because the board considers that the membership of the audit committee as a whole has sufficient recent and relevant financial experience to discharge its functions.

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.

Table of Contents

ITEM 16C PRINCIPAL ACCOUNTANT FEES AND SERVICES

The Audit Committee has established policies and procedures for the engagement of the independent auditor, 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 their expertise and experience with 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); 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,		
	2003	2002	2001
		($million)	
Audit fees			
Group audit	18	15	13
Audit-related regulatory reporting	5	4	4
Statutory audit of subsidiaries	13	10	8
	36	29	25
Audit-related fees			
Acquisition and disposal due diligence	9	13	20
Pension scheme audits	1	1	1
Other further assurance services	9	8	9
	19	22	30
Tax fees			
Compliance services	17	23	13
Advisory services	2	4	15
	19	27	28
Other fees		1	
Total non-audit fees	38	50	58

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 (2002 $4 million and 2001 $3 million) in respect of advice on accounting, auditing and financial reporting matters; $2 million

182

(2002 $3 million and 2001 $1 million) in respect of internal accounting and risk management control reviews; $2 million (2002 nil and 2001 $3 million) in respect of non-statutory audits and $2 million (2002 $1 million and 2001 $2 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 $44 million (2002 $33 million and 2001 $144 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

Not yet applicable.

Table of Contents

PART III

ITEM 17 FINANCIAL STATEMENTS

Not applicable.

ITEM 18 FINANCIAL STATEMENTS

The following financial statements, together with the reports of the Independent Auditors thereon, are filed as part of this annual report:

The following supplementary information is filed as part of this annual report:

ITEM 19 EXHIBITS

The following documents are filed as part of this annual report:

Exhibit 1.	Memorandum and Articles of Association of BP p.l.c.
Exhibit 4.1	The BP Executive Directors Long Term Incentive Plan*
Exhibit 4.2	Directors Service Contracts**
Exhibit 7.	Computation of Ratio of Earnings to Fixed Charges (Unaudited)
Exhibit 8.	Subsidiaries
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, 2000.

** Incorporated by reference to the Company s Annual Report on Form 20-F for the year ended December 31, 2002.

*** Furnished only.

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.

Table of Contents

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, 2003 and 2002, 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, 2003. 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of BP p.l.c. at December 31, 2003 and 2002, and the consolidated results of its operations and its consolidated cash flows for each of the three years in the period ended December 31, 2003, 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 48 of Notes to Financial Statements). Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ ERNST & YOUNG LLP

Ernst & Young LLP

London, England
February 9, 2004

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference of our report dated February 9, 2004, with respect to the consolidated financial statements of BP p.l.c. included in this Annual Report (Form 20-F) for the year ended December 31, 2003 in the following Registration Statements:

Registration Statements on Form F-3 (File Nos. 333-9790 and 333-65996) of BP p.l.c.;

Registration Statement on Form F-3 (File No. 333-83180) of BP Australia Capital Markets Limited, BP Canada Finance Company, BP Capital Markets p.l.c., BP Capital Markets America Inc. and BP p.l.c.; and

Registration Statements on Form S-8 (File Nos. 33-21868, 333-9020, 333-9798, 333-79399, 333-34968, 333-67206, 333-74414 and 333-102583, 333-103923 and 333-103924) of BP p.l.c.

/s/ ERNST & YOUNG LLP

London, England
June 28, 2004

Ernst & Young LLP

F - 1

Table of Contents

BP p.l.c. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF INCOME

	Note	2003	2002	2001
		Years ended December 31,		
		($ million, except per share amounts)		
Turnover		236,045	180,186	175,389
Less: Joint ventures		3,474	1,465	1,171
Group turnover	2	232,571	178,721	174,218
Cost of sales		202,029	154,401	148,893
Production taxes	3	1,723	1,274	1,689
Gross profit		28,819	23,046	23,636
Distribution and administration expenses	4	14,072	12,632	10,918
Exploration expense		542	644	480
		14,205	9,770	12,238
Other income	5	786	641	694
Group operating profit		14,991	10,411	12,932
Share of profits of joint ventures		924	347	439
Share of profits of associated undertakings		514	617	756
Total operating profit		16,429	11,375	14,127
Profit (loss) on sale of businesses or termination of operations	7	(28)	(33)	(68)
Profit (loss) on sale of fixed assets	7	859	1,201	603
Profit before interest and tax		17,260	12,543	14,662
Interest expense	8	851	1,279	1,670
Profit before taxation		16,409	11,264	12,992
Taxation	13	5,972	4,342	6,375
Profit after taxation		10,437	6,922	6,617
Minority shareholders interest		170	77	61
Profit for the year*		10,267	6,845	6,556
Dividend requirements on preference shares*		2	2	2
Profit for the year applicable to ordinary shares*		10,265	6,843	6,554
Profit per ordinary share cents				
Basic	16	46.30	30.55	29.21
Diluted	16	45.87	30.41	29.04

Dividends per ordinary share cents	15	26.00	24.00	22.00
Average number outstanding of 25 cents ordinary shares (in thousands)		22,170,741	22,397,126	22,435,737

* 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 48.

The Notes to Financial Statements are an integral part of this Statement.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

	Note	December 31, 2003		2002	
		($ million)			
Fixed assets					
Intangible assets	20		13,642		15,566
Tangible assets	21		91,911		87,682
Investments					
Joint ventures					
Gross assets		16,485		4,829	
Gross liabilities		5,111		798	
Minority shareholders interest		365			
Net investment	22		11,009		4,031
Associated undertakings	22		4,870		4,626
Other	22		1,675		2,154
			17,554		10,811
Total fixed assets			123,107		114,059
Current assets					
Inventories	23	11,617		10,181	
Trade receivables	24	23,487		18,798	
Other receivables falling due					
Within one year	24	7,897		8,107	
After more than one year	24	9,332		6,245	
Investments	25	185		215	
Cash at bank and in hand		1,947		1,520	
		54,465		45,066	
Current liabilities falling due within one year					
Finance debt	29	9,456		10,086	
Trade payables	30	20,858		17,454	
Other accounts payable and accrued liabilities	30	20,270		18,761	
		50,584		46,301	
Net current assets (liabilities)			3,881		(1,235)
Total assets less current liabilities			126,988		112,824
Noncurrent liabilities					
Finance debt	29	12,869		11,922	
Accounts payable and accrued liabilities	30	6,090		3,455	
Provisions for liabilities and charges					
Deferred taxation	13	15,273		13,514	
Other	31	15,693		13,886	

		49,925	42,777
Net assets		77,063	70,047
Minority shareholders interest equity		1,125	638
BP shareholders interest*		75,938	69,409
Represented by:			
Capital shares			
Preference		21	21
Ordinary		5,531	5,595
Paid in surplus	32	4,480	4,243
Merger reserve	32	27,077	27,033
Other reserves	32	129	173
Retained earnings	32/33	38,700	32,344
		75,938	69,409

* 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 48.

The Notes to Financial Statements are an integral part of this Balance Sheet.

[Table of Contents](#)

BP p.l.c. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS

	Note	Years ended December 31, 2003	2002	2001
			($ million)	
Net cash inflow from operating activities	34	21,698	19,342	22,409
Dividends from joint ventures		131	198	104
Dividends from associated undertakings		417	368	528
Servicing of finance and returns on investments				
Interest received		175	231	256
Interest paid		(1,006)	(1,204)	(1,282)
Dividends received		140	102	132
Dividends paid to minority shareholders		(20)	(40)	(54)
Net cash outflow from servicing of finance and returns on investments		(711)	(911)	(948)
Taxation				
UK corporation tax		(1,185)	(979)	(1,058)
Overseas tax		(3,619)	(2,115)	(3,602)
Tax paid		(4,804)	(3,094)	(4,660)
Capital expenditure and financial investment				
Payments for tangible and intangible fixed assets		(12,368)	(12,049)	(12,142)
Payments for fixed assets investments		(72)	(67)	(72)
Proceeds from the sale of fixed assets	19	6,253	2,470	2,365
Net cash outflow for capital expenditure and financial investment		(6,187)	(9,646)	(9,849)
Acquisitions and disposals				
Acquisitions, net of cash acquired		(211)	(4,324)	(1,210)
Proceeds from the sale of businesses	19	179	1,974	538
Acquisition of investment in TNK-BP joint venture		(2,351)		
Net investment in other joint ventures		(178)	(354)	(497)
Investments in associated undertakings		(987)	(971)	(586)
Proceeds from sale of investment in Ruhrgas	19		2,338	
Net cash outflow for acquisitions and disposals		(3,548)	(1,337)	(1,755)
Equity dividends paid		(5,654)	(5,264)	(4,827)

Net cash inflow (outflow)		1,342	(344)	1,002
Financing	34	1,066	(181)	972
Management of liquid resources	34	(41)	(220)	(211)
Increase (decrease) in cash	34	317	57	241
		1,342	(344)	1,002

For a cash flow statement and a statement of comprehensive income prepared on the basis of US GAAP see Note 48   US generally accepted accounting principles.

The Notes to Financial Statements are an integral part of this Statement.

F - 4

Table of Contents

BP p.l.c. AND SUBSIDIARIES

STATEMENT OF TOTAL RECOGNIZED GAINS AND LOSSES

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Profit for the year	10,267	6,845	6,556
Currency translation differences (net of tax)	3,841	3,333	(828)
Total recognized gains and losses relating to the year	14,108	10,178	5,728
Prior year adjustment change in accounting policy		(9,206)	
Total recognized gains and losses since last annual accounts		972	

The Notes to Financial Statements are an integral part of this Statement.

F - 5

Table of Contents

BP p.l.c. AND SUBSIDIARIES

STATEMENT OF CHANGES IN BP SHAREHOLDERS INTEREST

The Company s authorized ordinary share capital at December 31, 2003, 2002 and 2001 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 32.

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, 2003, 2002 and 2001	7,250,000	7,232,838	12
9% cumulative second preference shares of £1 each at December 31, 2003, 2002 and 2001	5,500,000	5,473,414	9
Equity ordinary shares of 25 cents each			
Authorized			
December 31, 2003, 2002 and 2001	36,000,000,000		

	Years ended December 31,					
	2003		2002		2001	
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	22,378,651	5,595	22,432,077	5,608	22,528,747	5,632
Employee share schemes (a)	32,889	8	33,821	9	33,461	8
Atlantic Richfield (b)	9,786	2	12,894	3	23,798	7
Repurchase of ordinary share capital (c)	(298,716)	(74)	(100,141)	(25)	(153,929)	(39)
December 31	22,122,610	5,531	22,378,651	5,595	22,432,077	5,608

Paid in surplus			
January 1	4,243	4,014	3,770
Premium on shares issued:			
Employee share schemes	127	129	118
Atlantic Richfield	36	54	51
Repurchase of ordinary share capital	74	25	39
Qualifying Employee Share Ownership Trust (d)		21	36
December 31	4,480	4,243	4,014

The Notes to Financial Statements are an integral part of this Statement.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

STATEMENT OF CHANGES IN BP SHAREHOLDERS INTEREST (Continued)

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Merger reserve			
January 1	27,033	26,983	26,869
Atlantic Richfield (b)	44	50	114
December 31	27,077	27,033	26,983
Other reserves			
January 1	173	223	456
Atlantic Richfield (b)	(44)	(50)	(117)
Redemption of Atlantic Richfield preference shares (e)			(116)
December 31	129	173	223
Retained earnings			
January 1	32,344	28,312	28,836
Currency translation differences (net of tax)	3,841	3,333	(828)
Repurchase of ordinary share capital	(1,999)	(750)	(1,281)
Qualifying Employee Share Ownership Trust (d)		(21)	(36)
Profit for the year	10,267	6,845	6,556
Dividends (f)			
Preference (non-equity)	(2)	(2)	(2)
Ordinary (equity)	(5,751)	(5,373)	(4,933)
December 31	38,700	32,344	28,312

(a) Employee share schemes. During the year 32,889,234 ordinary shares were issued under the BP, Amoco and Burmah Castrol employee share schemes.

(b) Atlantic Richfield. 9,786,396 ordinary shares were issued in respect of Atlantic Richfield employee share option schemes.

(c) Repurchase of ordinary share capital. The Company purchased for cancellation 298,716,391 ordinary shares for a total consideration of $1,999 million.

(d) See Note 35 Employee share plans.

(e) Redemption of Atlantic Richfield preference shares. A cash tender offer was made in March 2001 for the outstanding Atlantic Richfield preference shares.

(f) See Note 15 Dividends per ordinary share.

(g) See Note 33 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.

The Notes to Financial Statements are an integral part of this Statement.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

STATEMENT OF CHANGES IN BP SHAREHOLDERS   INTEREST (Concluded)

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.

Table of Contents

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 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 and gross liabilities of the joint venture (the gross equity method).

Certain of the Group s activities are conducted through joint arrangements and are included in the consolidated financial statements in proportion to the Group s interest in the income, expenses, assets and liabilities of these joint arrangements.

On the acquisition of a subsidiary, or of an interest in a joint venture or associate, fair values reflecting conditions at the date of acquisition are attributed to the identifiable net assets acquired. When the cost of acquisition exceeds the fair values attributable to the Group s share of such net assets the difference is treated as purchased goodwill. This is capitalized and amortized 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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Accounting policies (continued)

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 $150 million (2002 $209 million) and a revaluation reserve established and increased accordingly.

Revenue recognition

Revenues associated with the sale of oil, natural gas liquids, LNG, petroleum and chemical products and all other items are recognized when the title passes to the customer. Generally, revenues from the production of natural gas and oil properties in which the Group has an interest with other producers are recognized on the basis of the Group s working interest in those properties (the entitlement method). Differences between the production sold and the Group s share of production are not significant.

Foreign 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 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.

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Accounting policies (continued)

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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Accounting policies (continued)

***Derivative financial instruments* (continued)**

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 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 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, BP meets initial margin requirements by bank guarantees and daily margin calls in cash. For swaps and over-the-counter options, BP settles with the counterparty on conclusion of the pricing period.

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Accounting policies (continued)

***Derivative financial instruments* (concluded)**

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 the drilling of 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 not found, the exploration expenditure is written off as a dry hole. If hydrocarbons are found and, subject to further appraisal activity, are likely to be capable of commercial development, the costs continue to be carried as an asset. All such carried costs are subject to regular technical, commercial and management review 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 approved internally, 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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Accounting policies (continued)

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.

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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Accounting policies (continued)

Leases

Assets held under leases which result in Group companies receiving substantially all risks and rewards of ownership (finance leases) are capitalized as tangible fixed assets at the estimated present value of underlying lease payments. The corresponding finance lease obligation is included 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 during the period of construction where it relates either to the financing of major projects with long periods of development or to dedicated financing of other projects. All other interest is charged against income.

Pensions and other postretirement benefits

The cost of providing pensions and other postretirement benefits is charged to income on a systematic basis, with pension surpluses and deficits amortized over the average expected remaining service lives of current employees. The difference between the amounts charged to income and the contributions made to pension plans is included within other provisions or debtors as appropriate. The amounts accrued for other postretirement benefits and unfunded pension liabilities are included within other provisions.

Deferred taxation

Deferred 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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Accounting policies (concluded)

Discounting

The unwinding of the discount on provisions is included within interest expense. Any change in the amount recognized for environmental and other provisions arising through changes in discount rates is included within interest expense.

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 2001 has been restated to reflect the transfer of the solar, renewables and alternative fuels activities from Other businesses and corporate to Gas, Power and Renewables. Certain prior year figures have been restated to conform with the 2003 presentation.

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 2 Turnover

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Sales and operating revenue	278,859	222,231	208,299
Customs duties and sales taxes	46,288	43,510	34,081
	232,571	178,721	174,218

Note 3 Production taxes

	Years ended December 31,		
	2003	2002	2001
		($ million)	
UK petroleum revenue tax	300	309	600
Overseas production taxes	1,423	965	1,089
	1,723	1,274	1,689

Note 4 Distribution and administration expenses

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Distribution	12,559	11,431	9,852
Administration	1,513	1,201	1,066

	14,072	12,632	10,918

Distribution and administration expenses for 2002 include Veba from February 1.

Note 5 Other income

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Income from other fixed asset investments	157	139	208
Other interest and miscellaneous income	629	502	486
	786	641	694
Income from investments publicly traded included above	60	58	32

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 6 Auditors remuneration

	Years ended December 31,					
	2003		2002		2001	
	UK	Total	UK	Total	UK	Total
	($ million)					
Audit fees Ernst & Young						
Group audit	8	18	6	15	5	13
Audit-related regulatory reporting	2	5	2	4	2	4
Statutory audit of subsidiaries	3	13	2	10	1	8
	13	36	10	29	8	25
Fees for other services Ernst &Young						
Further assurance services						
Acquisition and disposal due diligence	9	9	9	13	16	20
Pension scheme audits		1		1		1
Other further assurance services	5	9	5	8	4	9
Tax services						
Compliance services	3	17	3	23		13
Advisory services		2	2	4	9	15
Other services			1	1		
	17	38	20	50	29	58

Group audit fees include $2 million (2002 $2 million and 2001 $2 million) in respect of the parent company.

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 $44 million (2002 $33 million and 2001 $144 million).

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

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,		
		2003	2002	2001
			($ million)	
Profit on sale of businesses or termination of operations	Group		195	182
Loss on sale of businesses or termination of operations	Group	(28)	(228)	(250)
		(28)	(33)	(68)
Profit on sale of fixed assets	Group	1,894	2,736	948
	Associated undertakings		2	
Loss on sale of fixed assets	Group	(1,035)	(1,537)	(343)
	Associated undertakings			(2)
		859	1,201	603
Exceptional items		831	1,168	535
Taxation credit (charge):				
Sale of businesses or termination of operations			45	(100)
Sale of fixed assets		(123)	(170)	(270)
Exceptional items (net of tax)		708	1,043	165

Sales of businesses or termination of operations

The profit in 2002 relates mainly to the disposal of the Group s retail network in Cyprus and the UK contract energy management business. For 2001 the profit relates to the sale of the Group s interest in Vysis.

The loss on sale of businesses or termination of operations for 2003 relates to the sale of our European oil speciality products business. For 2002, the loss 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. The loss during 2001 arose principally from the sale of the Group s Carbon Fibers business and the write-off of assets following the closure or exit from certain chemicals activities.

Sale of fixed assets

The major elements of the profit on sale of fixed assets in 2003 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 major part of the

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 7 Exceptional items (concluded)

profit 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. For 2001, the profit on the sale of fixed assets includes the profit from the divestment of the refineries at Mandan, North Dakota, and Salt Lake City, Utah; the Group s interest in the Alliance and certain other pipeline systems in the USA; and BP s interest in the Kashagan discovery in Kazakhstan.

The loss on sale of fixed assets in 2003 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 major element of the loss on sale of fixed assets in 2002 relates to provisions for losses on sale of exploration and production properties in the US announced in early 2003. For 2001, the loss on sale of fixed assets arose from a number of transactions.

Additional information on the sale of businesses and fixed assets is given in Note 19 Disposals.

Note 8 Interest expense

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Bank loans and overdrafts	38	134	119
Other loans (a)	628	852	1,111
Capital leases	34	40	78
	700	1,026	1,308
Capitalized at 3% (2002 4% and 2001 5%) (b)	190	100	81
Group	510	926	1,227
Joint ventures	89	58	70
Associated undertakings	45	83	135
Unwinding of discount on provisions	173	170	196
Unwinding of discount on deferred consideration for acquisition of investment in TNK-BP	34		
Change in discount rate for provisions		42	42

Total charged against profit	851	1,279	1,670

(a) Interest expense includes a charge of $31 million (2002 $15 million and 2001 $62 million) relating to early redemption of debt.

(b) Tax relief on capitalized interest is $68 million (2002 $36 million and 2001 $29 million).

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 9 Depreciation and amounts provided

Included in the income statement under the following headings:

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Depreciation and amortization of goodwill and other intangibles			
Cost of sales	9,748	9,346	7,475
Distribution	1,044	952	1,221
Administration	148	90	94
	10,940	10,388	8,790
Amounts provided against fixed asset investments			
Cost of sales		13	68
	10,940	10,401	8,858
Depreciation of capitalized leased assets included above	46	49	65

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 in total. 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 Kepadong 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.

The charge for depreciation and amortization of goodwill and intangibles in 2001 included $175 million for the impairment of the upstream Venezuela Lake Maracaibo operation.

In assessing the value in use of potentially impaired assets, a discount rate of 9% before tax has been used.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 10 Rental expense under operating leases

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Minimum rentals:			
Tanker charters	440	397	393
Plant and machinery	457	621	530
Land and buildings	548	342	355
	1,445	1,360	1,278
Less: Rentals from sub-leases	(128)	(166)	(165)
	1,317	1,194	1,113

Note 11 Research and development

Expenditure on research and development amounted to $349 million (2002 $373 million and 2001 $385 million).

Note 12 Currency exchange gains and losses

Accounted net foreign currency exchange gain included in the determination of profit for the year amounted to $171 million (2002 $66 million gain and 2001 $12 million gain).

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 13 Taxation

Tax on profit on ordinary activities

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Current tax:			
UK corporation tax	11,435	1,304	1,666
Overseas tax relief	(10,293)	(301)	(678)
	1,142	1,003	988
Overseas	3,525	1,883	3,846
Group	4,667	2,886	4,834
Joint ventures	158	75	94
Associated undertakings	94	187	203
	4,919	3,148	5,131
Deferred tax:			
UK	426	433	(48)
Overseas	655	761	1,292
Group	1,081	1,194	1,244
Joint ventures	(14)		
Associated undertakings	(14)		
	1,053	1,194	1,244
Tax on profit on ordinary activities	5,972	4,342	6,375

Included in the charge for the year is a charge of $123 million (2002 $125 million charge and 2001 $370 million charge) relating to exceptional items.

Tax included in statement of total recognized gains and losses

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Current tax:			
UK		57	(12)
Overseas	(11)	(54)	(4)
	(11)	3	(16)
Deferred tax:			
UK	48	138	(14)
Overseas		1	
	48	139	(14)
Tax included in statement of total recognized gains and losses	37	142	(30)

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 13 Taxation (continued)

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,		
	2003	2002	2001
		($ million)	
Analysis of profit before taxation:			
UK	5,513	2,822	2,333
Overseas	10,896	8,442	10,659
	16,409	11,264	12,992
Taxation	5,972	4,342	6,375
Effective tax rate	36%	39%	49%
		(% of profit before tax)	
UK statutory corporation tax rate	30	30	30
Increase (decrease) resulting from:			
UK supplementary and overseas taxes at higher rates	10	9	9
Tax credits		(3)	(3)
Restructuring benefits	(2)		
Current year losses unrelieved (prior year losses utilized)	(3)	1	4
No relief for inventory holding losses (inventory holding gains not taxed)	(1)	(2)	3
Acquisition amortization	4	7	6
Other	(2)	(3)	
Effective tax rate	36	39	49
Current year timing differences	(6)	(11)	(10)
Effective current tax rate	30	28	39

Current year timing differences arise mainly from the excess of tax depreciation over book depreciation.

Factors that may affect future tax charges

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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 13 Taxation (continued)

The Group has around $4.5 billion (2002 $5.3 billion) of carry-forward tax losses in the UK, which would be available to offset against future taxable income. To date, tax assets have been recognized on $285 million (2002 $840 million) of those losses (i.e. to the extent that it is regarded as more likely than not that suitable taxable income will arise). During 2003 the Group disclaimed tax depreciation allowances, which will be available in future periods, in order to optimize the utilization of tax losses. This is reflected in the movement in tax losses carried forward between the end of 2002 and 2003. 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. However, over the longer term, significant changes in the tax rate would arise only in the event of a substantial and sustained change in oil prices.

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 unlikely to change in the near term.

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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 13 Taxation (concluded)

Deferred tax

		At December 31, 2003	At December 31, 2002
		($ million)	
Analysis of provision:			
Depreciation		(15,613)	(14,990)
Other taxable timing differences		(1,957)	(1,837)
Petroleum revenue tax		601	567
Decommissioning and other provisions		1,429	2,192
Tax credit and loss carry forward		105	273
Other deductible timing differences		162	281
Deferred tax provision		(15,273)	(13,514)
of which	UK	3,741	2,906
	Overseas	11,532	10,608
Analysis of movements during the year:			
At January 1		13,514	11,702
Exchange adjustments		630	477
Acquisitions			6
Charge for the year on ordinary activities		1,081	1,194
Charge for the year in the statement of total recognized gains and losses		48	139
Deletions/transfers			(4)
At December 31		15,273	13,514

	Years ended December 31, 2003	2002	2001
	($ million)		
The charge for deferred tax on ordinary activities:			
Origination and reversal of timing differences	1,081	839	1,244
Effect of the introduction of supplementary UK corporation tax of 10% on opening liability		355	

	1,081	1,194	1,244
The charge (credit) for deferred tax in statement of total recognized gains and losses:			
Origination and reversal of timing differences	48	139	(14)

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 14 Quarterly results of operations (unaudited)

	Group turnover	Profit before interest and tax	Profit (loss) for the period	Profit (loss) per ordinary share
		($ million)		(cents)
Year ended December 31, 2003				
First quarter	62,031	6,318	4,267	19.11
Second quarter	54,426	3,653	1,634	7.41
Third quarter	58,250	4,100	2,394	10.85
Fourth quarter	57,864	3,189	1,972	8.93
Total	232,571	17,260	10,267	46.30
Year ended December 31, 2002				
First quarter	36,290	2,422	1,296	5.78
Second quarter	43,655	4,151	2,058	9.18
Third quarter	49,054	3,856	2,840	12.67
Fourth quarter	49,722	2,114	651	2.92
Total	178,721	12,543	6,845	30.55
Year ended December 31, 2001				
First quarter	45,412	5,452	2,830	12.59
Second quarter	48,409	5,156	2,741	12.21
Third quarter	43,580	3,509	1,588	7.08
Fourth quarter	36,817	545	(603)	(2.67)
Total	174,218	14,662	6,556	29.21

Note 15 Dividends per ordinary share

	Years ended December 31,								
	2003	2002	2001	2003	2002	2001	2003	2002	2001

	(pence per share)			(cents per share)			($ million)		
First quarterly	3.947	4.051	3.665	6.25	5.75	5.25	1,386	1,290	1,178
Second quarterly	4.039	3.875	3.911	6.50	6.00	5.50	1,433	1,346	1,235
Third quarterly	3.857	3.897	3.805	6.50	6.00	5.50	1,438	1,340	1,232
Fourth quarterly	3.674	3.815	4.055	6.75	6.25	5.75	1,494	1,397	1,288
	15.517	15.638	15.436	26.00	24.00	22.00	5,751	5,373	4,933

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 16 Profit per ordinary share

	Years ended December 31,		
	2003	2002	2001
	(cents per share)		
Basic earnings per share	46.30	30.55	29.21
Diluted earnings per share	45.87	30.41	29.04

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 $10,265 million (2002 $6,843 million and 2001 $6,554 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 $10,289 million (2002 $6,843 million and 2001 $6,554 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 three 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,		
	2003	2002	2001
	(shares thousand)		
Weighted average number of ordinary shares	22,170,741	22,397,126	22,435,737
Potential dilutive effect of ordinary shares issuable under employee share schemes	71,651	107,322	137,988
Potential dilutive effect of ordinary shares issuable as consideration for BP s interest in the TNK-BP venture	186,980		
	22,429,372	22,504,448	22,573,725

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 17 Operating lease commitments

Annual commitments under operating leases were as follows:

		At December 31,			
		2003		2002	
		Land and buildings	Other	Land and buildings	Other
		($ million)			
Expiring within:	1 year	70	186	80	174
	2 to 5 years	173	388	166	438
	Thereafter	262	291	289	188
		505	865	535	800

The minimum future lease payments (after deducting related rental income from operating sub-leases of $609 million) were as follows:

	December 31, 2003
	($ million)
2004	1,275
2005	1,066
2006	895
2007	799
2008	728
Thereafter	3,352
	8,115

Note 18 Acquisitions

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.

On August 29, BP and the Alfa Group and Access-Renova (AAR) combined 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. In addition BP paid AAR $2,306 million in cash and will subsequently pay three annual tranches of $1,250 million in BP ordinary shares, valued at market prices prior to each annual payment. Costs of the transaction amounted to $45 million. In exceptional and unanticipated circumstances BP may be required to settle these annual tranches in cash rather than shares.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 18 Acquisitions (continued)

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

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 18 Acquisitions (concluded)

Tangible fixed assets. The fair value attributed to exploration and production assets has been revised following further technical studies.

Other creditors. Liabilities existing at the date of acquisition have been revised following subsequent settlement.

Acquisitions in 2001

During the year the Group acquired the 50% of Erdölchemie, a petrochemicals business based in Germany, it did not already own. In addition a number of minor acquisitions were made. All these business combinations have been accounted for using the acquisition method of accounting. The assets and liabilities acquired as part of the 2001 acquisitions are shown in the above table in aggregate. The fair value of tangible fixed assets has been estimated by determining the net present value of future cash flows. No significant adjustments were made to the other acquired assets and liabilities.

	Fair value
	($ million)
Intangible assets	194
Tangible assets	841
Fixed assets Investments	18
Current assets (excluding cash)	428
Finance debt	(55)
Other creditors	(214)
Deferred taxation	(3)
Other provisions	(171)
Net investment in equity accounted entities transferred to full consolidation	(170)
Net assets acquired	868
Goodwill	48
Consideration	916

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 19 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.

Divestments in 2003. Cash received in 2003 from disposals amounted to $6,432 million. During the year the Group divested interests in a number of exploration and production properties. 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 for $1,165 million. A 12.5% interest in the Tangguh liquefied natural gas project in Indonesia was sold to CNOOC for $275 million. 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 for $120 million. 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 for $980 million.

In January, 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, BP called its $420 million Exchangeable Bonds which were exchangeable for Lukoil American Depositary Shares (ADSs). Bondholders converted to ADSs before the redemption date.

The Group sold its 50% interest in PT Kaltim Prima Coal, an Indonesian company, for $250 million.

As a condition of the approval of the acquisition of Veba, 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 for $146 million and the sale of retail and refinery assets in Germany and Central Europe to OMV for $394 million completed the divestments required.

Divestments in 2002. During the year, BP made a number of asset or business disposals.

The major asset transactions during the year included the sale of the Group s shareholding in Ruhrgas, 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 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. The Group entered into sale and leaseback transactions for certain chemicals manufacturing facilities in the UK, a solar manufacturing facility in Spain and an LNG tanker.

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.

BP closed its 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.

BP sold its plastic fabrications business, Fosroc Construction, its UK contract energy management business and its downstream retail businesses in Cyprus and Japan. The Group also announced its withdrawal from solar thin film manufacturing.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 19 Disposals (concluded)

Divestments in 2001. The major transactions in 2001 included the sale of the Group s interest in the Kashagan discovery in Kazakhstan; the divestment of the refineries at Mandan, North Dakota, and Salt Lake City, Utah; the sale of interests in the Alliance and certain other pipeline systems in the USA; and the disposal of the Group s majority interest in Vysis.

At December 31, 2000, the Foseco, Fosroc Construction, Fosroc Mining and Sericol speciality chemicals businesses that were acquired as part of the Burmah Castrol acquisition were categorized as businesses held for resale. Foseco was sold in July 2001. Fosroc Construction was sold in late 2002 and the sales of the remaining two businesses were announced in January 2003. These three businesses were consolidated from July 1, 2001 until their disposal.

A number of chemicals activities were either sold or terminated during 2001. Included in the businesses sold was the Carbon Fibers business.

The Group reduced its investment in Lukoil, which was acquired as part of the Atlantic Richfield acquisition, from 7% to 4% through the sale of 23.5 million shares.

To fulfil undertakings given to the European Commission at the time of the Atlantic Richfield acquisition, BP sold certain UK Southern North Sea natural gas interests in April 2001.

Total proceeds received for disposals represent the following amounts shown in the cash flow statement:

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Proceeds from the sale of businesses	179	1,974	538
Proceeds from the sale of fixed assets	6,253	2,470	2,365
Proceeds from the sale of investment in Ruhrgas		2,338	
	6,432	6,782	2,903

	Years ended December 31,		
	2003	2002	2001
The disposals comprise the following:		($ million)	
Intangible assets	322	205	183
Tangible assets (a)	6,212	2,545	1,481
Fixed asset Investments	890	1,769	898
Net assets of businesses held for resale		1,369	307
Finance debt	(420)	(1,135)	
Current assets less current liabilities	(498)	533	(145)
Other provisions	(971)	(109)	(112)
	5,535	5,177	2,612
Profit (loss) on sale of businesses or termination of operations	(28)	(33)	(68)
Profit (loss) on sale of fixed assets	859	1,199	605
Total consideration	6,366	6,343	3,149
Decrease (increase) in amounts receivable from disposals	66	439	(246)
Net cash inflow	6,432	6,782	2,903

(a) Includes provision for loss on disposal of $275 million (2002 $1,204 million and 2001 nil).

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 20 Intangible assets

	Exploration expenditure	Goodwill	Other intangibles	Total
		($ million)		
Cost				
At January 1, 2003	5,630	14,037	807	20,474
Exchange adjustments	72	671	2	745
Acquisitions		5		5
Additions	579		112	691
Transfers	(820)			(820)
Fair value adjustments		(289)		(289)
Deletions	(484)	(40)	(88)	(612)
At December 31, 2003	4,977	14,384	833	20,194
Depreciation				
At January 1, 2003	686	3,599	623	4,908
Exchange adjustments	10	263	2	275
Charge for the year	297	1,376	52	1,725
Transfers	(66)			(66)
Deletions	(186)	(23)	(81)	(290)
At December 31, 2003	741	5,215	596	6,552
Net book amount				
At December 31, 2003	4,236	9,169	237	13,642
At December 31, 2002	4,944	10,438	184	15,566

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 21 Tangible assets

Property, plant and equipment:

	Exploration and Production	Gas, Power and Renewables	Refining and Marketing	Petro-chemicals	Other businesses and corporate	Total	Of which: Assets under construction
				($ million)			
Cost							
At January 1, 2003	110,712	2,344	36,848	17,054	2,204	169,162	12,127
Exchange adjustments	3,718	222	3,570	1,199	111	8,820	216
Acquisitions			34			34	
Additions	9,384	275	2,918	529	185	13,291	10,800
Transfers	1,088		(84)			1,004	(7,359)
Fair value adjustments	(76)					(76)	
Deletions	(14,064)	(102)	(1,807)	(240)	(242)	(16,455)	(1,827)
At December 31, 2003	110,762	2,739	41,479	18,542	2,258	175,780	13,957
Depreciation							
At January 1, 2003	58,508	744	14,415	6,974	839	81,480	
Exchange adjustments	1,052	66	1,519	367	59	3,063	
Charge for the year	6,342	130	2,164	739	137	9,512	
Provision for loss on disposal	275					275	
Transfers	66		(9)			57	
Deletions	(9,313)	(70)	(865)	(129)	(141)	(10,518)	
At December 31, 2003	56,930	870	17,224	7,951	894	83,869	
Net book amount							
At December 31, 2003	53,832	1,869	24,255	10,591	1,364	91,911	13,957
At December 31, 2002	52,204	1,600	22,433	10,080	1,365	87,682	12,127

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, 2003	2,737	955	1,782	3,281	2,127	1,154
At December 31, 2002	1,694	904	790	3,329	1,617	1,712

	Decommissioning asset		
	Cost	Depreciation	Net
		($ million)	
At December 31, 2003	3,686	1,606	2,080
At December 31, 2002	2,848	1,551	1,297

		Leasehold land	
	Freehold land	Over 50 years unexpired	Other
		($ million)	
At December 31, 2003	3,466	71	203
At December 31, 2002	2,919	48	171

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 22 Fixed assets investments

	Joint ventures		Associated undertakings						
	Net assets (liabilities)	Loans	Net assets (liabilities)	Loans	Other Loans	Own shares (a)	Listed investments (b)	Other (c)	Total
					($ million)				
Cost									
At January 1, 2003	2,776	1,255	4,015	1,261	157	159	1,609	257	11,489
Exchange adjustments	70	52	58	138	14	8	21	7	368
Additions and net movements in joint ventures and associated undertakings	841	34	681	85		63	4	5	1,713
Acquisitions	5,794		35						5,829
Transfers	595		(984)	(64)	(37)				(490)
Deletions	(287)	(121)	187	(344)	(5)	(134)	(350)	(90)	(1,144)
At December 31, 2003	9,789	1,220	3,992	1,076	129	96	1,284	179	17,765
Amounts provided									
At January 1, 2003			219	431	19			9	678
Exchange adjustments			2					2	4
Provided in the year									
Transfers			(200)		(17)				(217)
Deletions				(254)					(254)
At December 31, 2003			21	177	2			11	211
Net book amount									
At December 31, 2003	9,789	1,220	3,971	899	127	96	1,284	168	17,554
At December 31, 2002	2,776	1,255	3,796	830	138	159	1,609	248	10,811

(a) Own shares are held in Employee Share Ownership Plans (ESOPs) to meet the future requirements of the employee share plans (see Note 35) and prior to award under the Long Term Performance Plan (see Note 36). At December 31, 2003 the ESOPs held 7,811,544 shares (18,673,675 shares at December 31, 2002) for the employee share schemes and 4,118,835 shares (3,901,317 shares at December 31, 2002) for the Long Term Performance Plan. The market value of these shares at December 31, 2003 was $96 million ($154 million at December 31, 2002).

(b) The market value of listed investments at December 31, 2003 was $3,212 million ($1,661 million at December 31, 2002).

(c) Other investments are not publicly traded.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 23 Inventories

	At December 31, 2003	At December 31, 2002
	($ million)	
Petroleum	6,623	6,138
Chemicals	1,165	966
Other	961	675
	8,749	7,779
Stores	938	893
	9,687	8,672
Trading inventories	1,930	1,509
	11,617	10,181
Replacement cost	11,717	10,610

Note 24 Receivables

	December 31, 2003		December 31, 2002	
	Within 1 year	After 1 year (a)	Within 1 year	After 1 year (a)
	($ million)			
Trade receivables	23,487		18,798	
Other receivables:				
Joint ventures	44		70	
Associated undertakings	337	53	282	96
Prepayments and accrued income	3,445	2,023	2,716	1,771
Taxation recoverable	78	14	94	9
Pension prepayment		6,814		3,899

Other	3,993	428	4,945	470
	7,897	9,332	8,107	6,245

Provisions for doubtful debts deducted from Trade receivables amounted to $441 million ($445 million at December 31, 2002).

(a) See Note 48 US generally accepted accounting principles.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 25 Current assets investments

		At December 31,	
		2003	2002
		($ million)	
Publicly traded	UK	42	32
	Foreign	37	29
		79	61
Not publicly traded		106	154
		185	215
Stock exchange value of publicly traded investments		79	61

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 26 Financial instruments

Financial instruments comprise primary financial instruments (cash, fixed and current asset investments, debtors, creditors, 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 27 and 28.

With the exception of the table of currency exposures shown on page F-41, short-term debtors and creditors 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, 2003			December 31, 2002		
	Finance debt	Other financial liabilities	Total	Finance debt	Other financial liabilities	Total

				($ million)			
Due within:	1 year	9,456		9,456	10,086		10,086
	1 to 2 years	2,702	2,087	4,789	913	597	1,510
	2 to 5 years	5,105	1,834	6,939	5,083	332	5,415
	Thereafter	5,062	2,266	7,328	5,926	2,218	8,144
		22,325	6,187	28,512	22,008	3,147	25,155

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 26 Financial instruments (continued)

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, 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	2,081	5,222
Sterling						5	267	267
Other currencies	5	4	303			6	395	698
			3,202		242		2,743	6,187
Total			3,921		21,848		2,743	28,512
At December 31, 2002								
Finance debt								
US dollar	7	7	7,818	2	13,287			21,105
Sterling				4	103			103
Other currencies	7	11	317	5	483			800
			8,135		13,873			22,008

Other financial liabilities								
US dollar	6	6	392	8	776	5	1,205	2,373
Sterling						6	171	171
Other currencies						2	603	603
			392		776		1,979	3,147
Total			8,527		14,649		1,979	25,155

	December 31,	
	2003	2002
	($ million)	
Analysis of the above financial liabilities by balance sheet caption:		
Current liabilities falling due within one year		
Finance debt	9,456	10,086
Noncurrent liabilities		
Finance debt	12,869	11,922
Accounts payable and accrued liabilities	4,542	1,953
Provisions for liabilities and charges		
Other provisions	1,645	1,194
	28,512	25,155

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 26 Financial instruments (continued)

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, 2003 was 97% 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, 2004 would change 2004 profit before tax by approximately $210 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,	
	2003	2002
	($ million except percentages)	
Receive fixed rate swaps notional amount	7,432	3,789
Average receive fixed rate	3.1%	5.0%
Average pay floating rate	1.1%	1.5%
Pay fixed rate swaps notional amount		2,169
Average pay fixed rate		6.6%
Average receive floating rate		1.5%

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, 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)
At December 31, 2002					
US dollar		323	2	301	626
Sterling	412		409	(33)	788
Other	(717)	(10)	(194)	(49)	(970)
	(305)	313	217	219	444

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 26 Financial instruments (concluded)

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 28.

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, 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
At December 31, 2002								
US dollar	3	2	180	1	873	2	1,094	2,147
Sterling	7	2	94	5	171	2	235	500
Other currencies	2	1	34	1	208	1	1,264	1,506
			308		1,252		2,593	4,153

	December 31,	
	2003	2002

	($ million)	
Analysis of the above financial assets by balance sheet caption:		
Fixed assets investments	1,579	1,995
Current assets		
Receivables amounts falling due after more than one year	428	423
Investments	185	215
Cash at bank and in hand	1,947	1,520
	4,139	4,153

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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 27 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, 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
Gains and losses at January 1, 2002	109	(235)	(126)	113	(327)	(214)
of which accounted for in income in 2002	60	(19)	41	50	(162)	(112)
Gains and losses at December 31, 2002	526	(450)	76	352	(28)	324
of which expected to be recognized in income in 2003	96	(51)	45	200	(14)	186

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.

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 27 Derivative financial instruments (continued)

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,			
	2003		2002	
	Fair value asset	Fair value liability	Fair value asset	Fair value liability
	($ million)			
Interest rate contracts				
Foreign exchange contracts	30	(54)	29	(17)
Oil price contracts	586	(667)	440	(418)
Natural gas price contracts	858	(711)	1,112	(955)
Power price contracts	548	(514)	182	(163)
	2,022	(1,946)	1,763	(1,553)

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,							
	2003				2002			
	High	Low	Average	Year end	High	Low	Average	Year end
	($ million)							
Interest rate trading	1							
Foreign exchange trading	4		2	1	2		1	
Oil price trading	34	17	26	27	34	14	23	19
Natural gas price trading	29	4	16	18	18	1	6	9
Power price trading	13		4	6	9	1	4	3

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 27 Derivative financial instruments (concluded)

The presentation of trading results shown in the table below includes certain activities of BP s trading function 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,	
	2003	2002
	Net gain (loss)	Net gain (loss)
	($ million)	
Interest rate trading	9	
Foreign exchange trading	118	90
Oil price trading	825	597
Natural gas price trading	341	199
Power price trading	119	74
	1,412	960

Note 28 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 debtors and creditors 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 .

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 28 Fair values of financial assets and liabilities (continued)

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, 2003, 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,			
		2003		2002	
		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		3,507	1,579	2,047	1,995
Current assets					
Other receivables amounts falling due after more than one year		428	428	423	423
Investments		185	185	215	215
Cash at bank and in hand		1,947	1,947	1,520	1,520
Finance debt					
Short-term borrowings		(5,059)	(5,059)	(5,504)	(5,504)
Long-term borrowings		(16,190)	(15,559)	(15,476)	(14,609)
Net obligations under finance leases		(2,479)	(2,452)	(2,183)	(2,172)
Noncurrent liabilities					
Accounts payable and accrued liabilities		(4,542)	(4,542)	(1,953)	(1,953)
Provisions for liabilities and charges					
Other provisions		(1,645)	(1,645)	(1,194)	(1,194)
Derivative financial or commodity instruments					
Risk management	interest rate contracts	5		(63)	
	foreign exchange contracts	941	745	416	277
	oil price contracts	(5)	(5)	9	9
	natural gas price contracts	(5)	(5)	5	5
	power price contracts	(10)	(10)		
Trading	interest rate contracts				
	foreign exchange contracts	(24)	(24)	12	12
	oil price contracts	(81)	(81)	22	22
	natural gas price contracts	147	147	157	157
	power price contracts	34	34	19	19

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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 28 Fair values of financial assets and liabilities (concluded)

Current assets Other receivables amounts falling due after more than one year. The fair value of other receivables due after one year is estimated not to be materially different from its carrying value.

Current assets Investments and Cash at bank and in hand. The carrying amount reported in the balance sheet for unlisted current asset investments and cash at bank and in hand approximates their fair value. The fair value of listed current asset investments has been determined by reference to market prices.

Finance debt. The carrying amount of the Group s short-term borrowings, which mainly comprise commercial paper, bank loans and overdrafts, approximates their fair value. The fair value of the Group s long-term borrowings and finance lease obligations is estimated using quoted prices or, where these are not available, discounted cash flow analyses, based on the Group s current incremental borrowing rates for similar types and maturities of borrowing.

Noncurrent liabilities Accounts payable and accrued liabilities. 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 29 Finance debt

	December 31, 2003			December 31, 2002		
	Within 1 year (a)	After 1 year	Total	Within 1 year (a)	After 1 year	Total

			($ million)			
Bank loans	205	253	458	476	344	820
Other loans	9,161	10,524	19,685	9,526	9,656	19,182
Total borrowings	9,366	10,777	20,143	10,002	10,000	20,002
Net obligations under capital leases	90	2,092	2,182	84	1,922	2,006
	9,456	12,869	22,325	10,086	11,922	22,008

(a) Amounts due within one year include current maturities of long-term debt.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 29 Finance debt (continued)

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 $745 million (an asset of $277 million at December 31, 2002) 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 $2,503 million (December 31, 2002 $1,881 million) with maturity periods ranging up to 35 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, 2003, the Group s share of third party finance debt of joint ventures and associated undertakings was $2,151 million (December 31, 2002 $457 million) and $922 million (December 31, 2002 $849 million) respectively. These amounts are not reflected in the Group s debt on the balance sheet.

Analysis of borrowings by year of repayment		December 31, 2003			December 31, 2002		
		Bank loans	Other loans	Total	Bank loans	Other loans	Total
				($ million)			
Due after	10 years		721	721		1,417	1,417
Due within	10 years		17	17	1	371	372
	9 years		337	337	43	310	353
	8 years		291	291		15	15
	7 years					1,699	1,699
	6 years	7	1,700	1,707		516	516
	5 years	7	938	945		1,603	1,603
	4 years	8	1,291	1,299	161	344	505
	3 years	193	2,593	2,786	19	2,671	2,690
	2 years	38	2,636	2,674	120	710	830
		253	10,524	10,777	344	9,656	10,000
	1 year	205	9,161	9,366	476	9,526	10,002
		458	19,685	20,143	820	19,182	20,002

Amounts included above repayable by instalments, part of which falls due after five years from December 31, are as follows:

	At December 31,	
	2003	2002
	($ million)	
After five years	14	541
Within five years	82	103
	96	644

F - 48

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 29 Finance debt (continued)

Interest rates on borrowings repayable wholly or partly more than five years from December 31, 2003 range from 1% to 12% with a weighted average of 4%. The weighted average interest rate on finance debt is 2%.

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, 2003
		($ million)
2004		127
2005		243
2006		248
2007		240
2008		248
Thereafter		3,528
		4,634
Less: amount representing lease interest		(2,452)
Present value of net minimum capital lease payments		2,182
of which	due within one year	90
	due after one year	2,092

The following information is presented in compliance with the requirements of US GAAP.

Bank and other loans long term

December 31,

	Weighted average interest rate at December 31,			
	2003	2002	2003	2002
	(%)		($ million)	
US dollar	3	5	10,427	9,796
Sterling	4	4	30	26
Other currencies	5	9	320	178
			10,777	10,000

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 29 Finance debt (concluded)

Bank and other loans short term

	December 31, 2003	December 31, 2002
	($ million)	
Current maturities of long-term debt	1,874	2,535
Commercial paper	4,243	4,853
Bank loans	205	476
Other	3,044	2,138
	9,366	10,002

	Weighted average interest rate at December 31, 2003	2002
	(%)	
Commercial paper	1	1
Bank loans and other borrowings	2	4
US Industrial Revenue/Municipal bonds	1	1

Note 30 Accounts payable and accrued liabilities

	December 31, 2003		December 31, 2002	
	Within 1 year	After 1 year	Within 1 year	After 1 year
	($ million)			
Trade payables	20,858		17,454	

Other accounts payable and accrued liabilities:				
Joint ventures	126		22	
Associated undertakings	322	4	287	12
Production taxes	421	1,544	421	1,455
Taxation on profits	3,441		3,420	
Social security	96		81	
Accruals and deferred income	6,411	1,321	5,763	1,002
Dividends	1,495		1,398	
Other	7,958	3,221	7,369	986
	20,270	6,090	18,761	3,455

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 31 Other provisions

	Decommissioning	Environmental	Unfunded pension plans	Other postretirement benefits	Other	Total
			($ million)			
At January 1, 2003	4,168	2,122	3,146	2,762	1,688	13,886
Exchange adjustments	257	28	603		28	916
New provisions	1,159	515	478	377	364	2,893
Unwinding of discount	107	46			20	173
Utilized/deleted	(971)	(413)	(273)	(215)	(303)	(2,175)
At December 31, 2003	4,720	2,298	3,954	2,924	1,797	15,693

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, 2003, the provision for the costs of decommissioning these production facilities and pipelines at the end of their economic lives was $4,720 million (2002 $4,168 million). The provision has been estimated using existing technology, at current prices and discounted using a real discount rate of 2.5% (2002 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 $7,504 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, 2003 was $2,298 million (2002 $2,122 million). The provision has been estimated using existing technology, at current prices and discounted using a real discount rate of 2.5% (2002 2.5%). 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 $2,430 million.

The Group also holds provisions for potential future awards under the long-term performance plans, expected rental shortfalls on surplus properties and sundry other liabilities. To the extent that these liabilities are not expected to be settled within the next three years, the provisions are discounted using a real discount rate of 2.5% (2002 2.5%).

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 32 Capital and reserves

	Share capital	Paid in surplus	Merger reserve	Other reserves	Retained earnings	Total
			($ million)			
At January 1, 2003	5,616	4,243	27,033	173	32,344	69,409
Currency translation differences (net of tax)					3,841	3,841
Employee share schemes	8	127				135
Atlantic Richfield	2	36	44	(44)		38
Repurchase of ordinary share capital	(74)	74			(1,999)	(1,999)
Profit for the year					10,267	10,267
Dividends					(5,753)	(5,753)
At December 31, 2003	5,552	4,480	27,077	129	38,700	75,938

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 32,889,234 ordinary shares were issued under the BP, Amoco and Burmah Castrol employee share schemes.

Atlantic Richfield. 9,786,396 ordinary shares were issued in respect of Atlantic Richfield employee share option schemes.

Repurchase of ordinary share capital. The Company purchased for cancellation 298,716,391 ordinary shares for a total consideration of $1,999 million.

Note 33 Retained earnings

Retained earnings of $38,700 million ($32,344 million at December 31, 2002) include the following amounts, the distribution of which is limited by statutory or other restrictions:

	December 31,	
	2003	2002
	($ million)	
Parent company	24,107	9,547
Subsidiary undertakings	2,115	5,620
Joint ventures and associated undertakings	566	870
	26,788	16,037

Cumulative net exchange gain (net of tax) of $2,632 million are included in retained earnings ($1,209 million losses at December 31, 2002).

There were no unrealized currency translation differences for the year on long-term borrowings used to finance equity investments in foreign currencies (2002 nil and 2001 nil).

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 34 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,		
	2003	2002	2001
		($ million)	
Profit before interest and tax	17,260	12,543	14,662
Depreciation and amounts provided	10,940	10,401	8,858
Exploration expenditure written off	297	385	238
Share of profits of joint ventures and associated undertakings	(1,438)	(966)	(1,194)
Interest and other income	(341)	(358)	(478)
(Profit) loss on sale of fixed assets and businesses or termination of operations	(831)	(1,166)	(537)
Charge for provisions	1,734	1,277	1,008
Utilization of provisions	(1,204)	(1,427)	(1,119)
(Increase) decrease in inventories	(841)	(1,521)	1,490
(Increase) decrease in receivables	(5,628)	(2,672)	1,989
Increase (decrease) in payables	1,750	2,846	(2,508)
Net cash inflow from operating activities	21,698	19,342	22,409

Financing

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Long-term borrowing	(4,322)	(3,707)	(1,296)
Repayments of long-term borrowing	3,560	2,369	2,602
Short-term borrowing	(4,706)	(9,849)	(6,257)
Repayments of short-term borrowing	4,708	10,451	4,823
	(760)	(736)	(128)
Issue of ordinary share capital for employee share schemes	(173)	(195)	(181)

Repurchase of ordinary share capital	1,999	750	1,281
Net cash (inflow) outflow	1,066	(181)	972

Management of liquid resources

Liquid resources comprise current asset investments, which are principally commercial paper issued by other companies. The net cash inflow from the management of liquid resources was $41 million (2002 $220 million inflow and 2001 $211 million inflow).

Commercial paper

Net movements in commercial paper are included within short-term borrowings or repayment of short-term borrowings as appropriate.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 34 Analysis of consolidated statement of cash flows (concluded)

Movement in net debt

	Years ended December 31,							
	2003				2002			
	Finance debt	Cash	Current asset investments	Net debt	Finance debt	Cash	Current asset investments	Net debt
	($ million)							
At January 1	(22,008)	1,520	215	(20,273)	(21,417)	1,358	450	(19,609)
Exchange adjustments	(199)	110	11	(78)	(64)	105	(15)	26
Acquisitions	(15)			(15)	(1,002)			(1,002)
Net cash flow	(760)	317	(41)	(484)	(736)	57	(220)	(899)
Partnership interests exchanged for BP loan notes					1,135			1,135
Debt transferred to TNK-BP	93			93				
Exchange of Exchangeable Bonds for Lukoil American Depositary Shares	420			420				
Other movements	144			144	76			76
At December 31	(22,325)	1,947	185	(20,193)	(22,008)	1,520	215	(20,273)

Note 35 Employee share plans

Employee share options granted during the year (a)

	Years ended December 31,		
	2003	2002	2001
	(options thousands)		

Savings related schemes	23,922	9,719	7,901
Executive Directors Incentive Plan	2,728	2,068	2,598
BP Share Option Plan	78,109	66,771	58,208
	104,759	78,558	68,707

(a) The exercise prices for BP options granted during the year were £3.50/$5.70 (23,922,346 options) for savings-related and similar plans; £3.88/$6.32 (weighted average price) for Executive Directors Incentive Plan (2,728,026 options); and £3.91/$6.38 (weighted average price) for 78,108,230 options granted under the BP Share Option Plan.

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 36) and the granting of share options as elements of remuneration for executive directors and senior employees.

During 2003, 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

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 35 Employee share plans (continued)

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 36) 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 2003 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.

BP does not recognize an expense in respect of share options granted to employees. 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,		
	2003	2002	2001
Risk-free interest rate	3.5%	4.0%	5.0%
Expected volatility	30%	26%	26%
Expected life in years	1 to 5	1 to 5	1 to 5
Expected dividend yield	4.0%	3.75%	3.0%
Weighted average fair value of options granted ($)	1.44	1.64	2.05

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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 35 Employee share plans (continued)

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Profit for the year applicable to ordinary shares, as reported	10,265	6,843	6,554
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(79)	(90)	(102)
Pro forma net income	10,186	6,753	6,452

		(cents)	
Earnings per share			
Basic as reported	46.30	30.55	29.21
Basic pro forma	45.94	30.15	28.76
Diluted as reported	45.87	30.41	29.04
Diluted pro forma	45.41	30.01	28.58

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. Company contributions are initially invested in a fund primarily comprised of BP ADSs but employees may transfer those amounts and may invest their own contributions in more than 200 investment options. The Company s contributions generally vest over a period of three years. Company contributions to savings plans during the year were $130 million (2002 $125 million and 2001 $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. The Company provides funding to the ESOP. The assets and liabilities of the ESOP are recognized as assets and liabilities of the Company within the accounts. The ESOP has waived its rights to dividends.

During 2003, the ESOP released 16,892,853 shares (2002 15,332,235 shares and 2001 11,508,754 shares) for the matching share plans. The cost of shares released for these plans has been charged in these accounts. At December 31, 2003, the ESOP held 7,811,544 shares (18,673,675 shares at December 31, 2002).

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 35 Employee share plans (continued)

	Years ended December 31,		
	2003	2002	2001
	(shares thousands)		
Shares issued in respect of options exercised during the year:			
Savings related schemes	5,325	10,412	8,842
BP, Amoco and Burmah Castrol executive share option plans	27,564	23,409	24,619
	32,889	33,821	33,461

	2003	2002	2001
Options outstanding at December 31:			
BP options (shares thousands)	461,886	410,986	373,858
Exercise period	2004-2013	2003-2012	2002-2011
Price	£ 1.86-£6.40	£ 1.50-£6.40	£ 1.29-£6.40
Price	$ 3.47-$9.97	$ 3.47-$9.97	$ 2.77-$9.97

The following table summarizes share option transactions under employee share plans.

	Years ended December 31,					
	2003		2002		2001	
	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	410,986,179	6.70	373,857,979	6.20	343,218,324	5.61
Reinstated	35,876	7.57	24,310	5.08	7,152	7.84
Granted	104,758,602	6.22	78,557,576	8.07	68,706,983	8.13
Exercised	(32,988,942)	4.11	(34,130,302)	4.20	(33,592,964)	3.97
Cancelled	(20,905,834)	7.05	(7,323,384)	7.59	(4,481,516)	7.37
Outstanding at December 31	461,885,881	6.76	410,986,179	6.70	373,857,979	6.20

Exercisable at December 31	229,198,494	239,241,597	241,268,277
Available for grant at December 31	1,079,531,345	1,159,841,669	1,185,523,186

Options outstanding at December 31, 2003 will be exercisable between 2004 and 2013.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 35 Employee share plans (concluded)

For the share options outstanding and exercisable at December 31, 2003 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					
$2.85 - $4.61	59,829,939	1.51	4.13	59,310,812	4.13
$5.02 - $6.47	178,023,570	6.08	5.92	78,998,886	5.58
$6.49 - $8.28	189,923,295	6.52	8.02	79,675,686	7.97
$8.33 - $10.10	34,109,077	7.29	8.78	11,213,110	9.17
	461,885,881	5.76	6.76	229,198,494	6.21

Note 36 Long term performance plans

During 2003, 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 2003 in respect of the 2000-2002 LTPP. Further details of the plans are given in Item 6 Directors, Senior Management and Employees Compensation on page 135.

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 2003 was $94 million (2002 $51 million and 2001 $80 million). The value of awards under the 2000-2002 LTPP made in 2003 was $35 million (1999-2001 LTPP made in 2002 $125 million and 1998-2000 LTPP made in 2001 $61 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 $17 million (2002 $19 million and 2001 $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, 2003 the ESOPs held 4,118,835 shares (at December 31, 2002, 3,901,317 shares) for potential future awards.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 37 Employee costs and numbers

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Employee costs			
Wages and salaries	7,142	6,519	6,361
Social security costs	622	490	474
Pension and other postretirement benefit costs	936	440	427
	8,700	7,449	7,262

	At December 31,		
	2003	2002	2001
Number of employees			
Exploration and Production	15,350	16,800	16,550
Gas, Power and Renewables	3,550	4,400	4,200
Refining and Marketing (a)	66,150	72,300	64,600
Petrochemicals	15,950	18,950	21,950
Other businesses and corporate	2,700	2,800	2,850
	103,700	115,250	110,150

(a) Includes 26,950 (2002 30,250 and 2001 28,500) service station staff.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 37 Employee costs and numbers (concluded)

	UK	Rest of Europe	USA	Rest of World	Total
Average number of employees					
Year ended December 31, 2003					
Exploration and Production	3,200	750	5,200	6,900	16,050
Gas, Power and Renewables	250	950	1,250	1,550	4,000
Refining and Marketing	9,900	19,600	26,950	12,300	68,750
Petrochemicals	2,650	5,950	6,250	1,800	16,650
Other businesses and corporate	1,250		1,350	100	2,700
	17,250	27,250	41,000	22,650	108,150
Year ended December 31, 2002					
Exploration and Production	3,750	800	5,550	6,800	16,900
Gas, Power and Renewables	500	850	1,400	1,550	4,300
Refining and Marketing	10,200	20,650	28,650	11,550	71,050
Petrochemicals	3,200	6,300	6,650	5,150	21,300
Other businesses and corporate	1,250		1,400	100	2,750
	18,900	28,600	43,650	25,150	116,300
Year ended December 31, 2001					
Exploration and Production	3,550	750	5,700	6,200	16,200
Gas, Power and Renewables	600	600	1,350	1,350	3,900
Refining and Marketing	10,400	16,450	27,300	11,750	65,900
Petrochemicals	3,600	5,750	7,550	3,300	20,200
Other businesses and corporate	1,350		1,500	100	2,950
	19,500	23,550	43,400	22,700	109,150

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 38 Directors remuneration

	Years ended December 31,		
	2003	2002	2001
	($ million)		
Total for all directors			
Emoluments	17	14	17
Ex gratia payment to executive director retiring in 2003	1		
Non-executive directors retiring in 2001			1
Gains made on the exercise of share options	1		
Amounts awarded under incentive schemes	4	14	17

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 2003.

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 39 Loans to officers

During the year Miss J C Hanratty repaid a low interest loan of $43,000 made to her prior to her appointment as company secretary on October 1, 1994.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 40 Pensions

Most Group companies have pension plans, the forms and benefits of which vary with conditions and practices in the countries concerned. Pension benefits may be provided through defined contribution plans (money purchase schemes) or defined benefit plans (final salary schemes). For defined contribution plans, retirement benefits are determined by the value of funds arising from contributions paid in respect of each employee. For defined benefit plans, retirement benefits are based on the employees 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 cumulative difference, since the adoption of Statement of Standard Accounting Practice No. 24 Accounting for Pension Costs (SSAP 24), between the contributions paid by BP to the pension funds and the pension expense recorded each year is reflected in the balance sheet. If the cumulative contributions exceed pension expense the difference is shown as a prepayment on the balance sheet. If the cumulative contributions are less than pension expense the difference is shown as a provision on the balance sheet. For unfunded plans, where assets are not held with the specific purpose of matching pension obligations, the accrued liability for pension benefits is included within other provisions. The majority of the Group s employees are members of defined benefit plans. 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. The date of the most recent actuarial reviews was December 31, 2003.

During 2003 contributions of $258 million and $2,189 million were made to the UK plans and the US plans respectively. In addition contributions of $86 million were made to other funded defined benefit plans. The aggregate level of contributions in 2004 is expected to be approximately $400 million.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 40 Pensions (continued)

The pension assumptions for the principal pension 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, 2003 are used to determine the pension liabilities at that date and the pension cost for 2004. This applies for all accounting bases described in this note.

	At December 31,			
	2003	2002	2001	2000
	(%)			
UK plans:				
Rate of return on assets	6.0	6.25	6.0	6.5
Discount rate	6.0	6.25	6.0	6.5
Future salary increases	4.0	4.0	4.5	5.0
Future pension increases	2.5	2.5	2.5	3.0
Dividend growth	n/a	n/a	n/a	n/a
US plans:				
Rate of return on assets	8.0	8.0	10.0	10.0
Discount rate	6.0	6.75	7.25	7.5
Future salary increases	4.0	4.0	4.0	4.0
Future pension increases	nil	nil	nil	nil
Dividend growth	n/a	n/a	n/a	n/a
Other plans:				
Rate of return on assets	6.0	6.0	6.5	6.5
Discount rate	5.5	5.75	6.25	6.25
Future salary increases	4.0	4.0	3.25	3.25
Future pension increases	2.5	2.5	2.0	2.0
Dividend growth	n/a	n/a	n/a	n/a

n/a = not applicable

Pension costs for the UK and US plans have been derived using the projected unit credit method and by amortizing surpluses and deficits on a straight line basis over the average expected remaining service lives of the current employees. An analysis of pension expense is set out below.

	Years ended December 31,		
	2003	2002	2001

		($ million)	
Defined benefit plans:			
UK	(371)	(297)	(226)
USA	283	133	140
Other	477	175	198
	389	11	112
Defined contribution plans	170	153	155
	559	164	267

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 40 Pensions (continued)

At December 31, 2003, the market value and actuarial value of assets in the Group s UK and US funded pension plans and the market value and actuarial value of those assets in relation to the benefits that had accrued to members of those plans, after allowing for expected future increases in salaries, are set out below.

	UK		US	
	2003	2002	2003	2002
Market value of plan assets ($ million)	19,224	15,138	6,857	4,206
as a percentage of accrued benefits	117%	111%	88%	62%
Actuarial value of plan assets ($ million)	20,785	19,074	7,445	5,818
as a percentage of accrued benefits	126%	140%	97%	86%
Prepayment ($ million)	3,670	2,688	3,144	1,211

At December 31, 2003 the obligation for accrued benefits in respect of the unfunded and other funded plans was $4,637 million ($3,694 million at December 31, 2002). Of this amount, $3,954 million ($3,146 million at December 31, 2002) has been provided in these accounts.

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	One-percentage point decrease
	($ million)	
Investment return:		
Effect on pension expense in 2004	(270)	270
Discount rate:		
Effect on pension expense in 2004	(320)	420
Effect on pension obligation at December 31, 2003	(3,290)	4,240

For 2003 and 2002 the Group has accounted for pensions in accordance with SSAP 24. However, there is a new accounting standard, Financial Reporting Standard No. 17 Retirement Benefits (FRS 17), which changes the basis of accounting for pensions and other postretirement benefits and requires certain disclosures in the periods prior to adoption. The additional disclosures for the year ended December 31, 2003 and earlier periods are shown in the following tables. The Group has adopted FRS 17 with effect from January 1, 2004.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 40 Pensions (continued)

The expected long-term rates of return and market values of the various categories of asset held by the significant defined benefit plans and the main assumptions used to evaluate plan liabilities at December 31, on an FRS 17 basis are set out below.

	At December 31,					
	2003		2002		2001	
	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	14,642	7.5	10,815	7.5	12,228
Bonds	4.75	2,477	5.0	2,263	5.5	2,449
Property	6.5	1,336	6.5	1,352	6.5	1,057
Cash	4.0	769	4.0	708	4.5	1,146
	7.0	19,224	7.0	15,138	7.0	16,880
Present value of plan liabilities		17,766		14,822		12,746
Surplus in the plans		1,458		316		4,134
Deferred tax		(437)		(95)		(1,240)
		1,021		221		2,894
US plans:						
Equities	8.5	5,650	8.5	3,371	11.0	4,537
Bonds	4.75	1,018	5.5	720	7.0	942
Property	8.0	41	8.0	49	8.0	51
Cash	3.5	148	3.5	66	4.0	95
	8.0	6,857	8.0	4,206	10.0	5,625
Present value of plan liabilities		7,709		6,765		6,146
Deficit in the plans		(852)		(2,559)		(521)
Deferred tax		307		921		188
		(545)		(1,638)		(333)

Other plans:						
Equities	7.5	686	7.5	515	7.5	557
Bonds	4.75	737	5.0	672	5.5	375
Property	6.5	129	6.5	101	6.5	90
Cash	4.0	187	4.0	159	4.5	142
	6.0	1,739	6.0	1,447	6.5	1,164
Present value of plan liabilities		6,376		5,141		3,101
Deficit in the plans		(4,637)		(3,694)		(1,937)
Deferred tax		302		249		231
		(4,335)		(3,445)		(1,706)

F - 65

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 40 Pensions (continued)

	At December 31,		
	2003	2002	2001
		(%)	
Other main assumptions for FRS 17 disclosures as at December 31			
UK plans:			
Discount rate for plan liabilities	5.5	5.75	6.0
Rate of increase in salaries	4.0	4.0	4.5
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	6.0	6.75	7.25
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	3.0
Other plans:			
Discount rate for plan liabilities	5.5	5.75	6.25
Rate of increase in salaries	4.0	4.0	3.25
Rate of increase for pensions in payment	2.5	2.5	2.0
Rate of increase in deferred pensions	2.5	2.5	2.0
Inflation	2.5	2.5	2.0

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 40 Pensions (continued)

	Year ended December 31, 2003			
	UK	US	Other	Total
	($ million)			
Analysis of the amount that would be charged to operating profit on an FRS 17 basis				
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 that would be credited (charged) to other finance income on an FRS 17 basis				
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 that would be recognized in the statement of total recognized gains and losses on an FRS 17 basis				
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 on an FRS 17 basis				
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)

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 40 Pensions (continued)

	Year ended December 31, 2002			
	UK	US	Other	Total
	($ million)			
Analysis of the amount that would be charged to operating profit on an FRS 17 basis				
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 that would be credited (charged) to other finance income on an FRS 17 basis				
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 that would be recognized in the statement of total recognized gains and losses on an FRS 17 basis				
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 on an FRS 17 basis				
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)

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 40 Pensions (continued)

	At December 31, 2003		
	UK	US	Other
History of experience gains and losses which would be recognized on an FRS 17 basis			
Difference between the expected and actual return on plan assets:			
Amount ($ million)	1,639	749	2
Percentage of plan assets	9%	11%	0%
Experience gains and losses on plan liabilities:			
Amount ($ million)	641	30	135
Percentage of the present value of the plan liabilities	4%	0%	2%
Total amount recognized in statement of total recognized gains and losses:			
Amount ($ million)	843	(251)	(142)
Percentage of the present value of the plan liabilities	5%	(3)%	(2)%

	At December 31, 2002		
	UK	US	Other
History of experience gains and losses which would be recognized on an FRS 17 basis			
Difference between the expected and actual return on plan assets:			
Amount ($ million)	(3,874)	(1,305)	(137)
Percentage of plan assets	(26)%	(31)%	(9)%
Experience gains and losses on plan liabilities:			
Amount ($ million)	212	(290)	90
Percentage of the present value of the plan liabilities	1%	(4)%	2%
Total amount recognized in statement of total recognized gains and losses:			
Amount ($ million)	(4,142)	(1,938)	(487)
Percentage of the present value of the plan liabilities	(28)%	(29)%	(9)%

	At December 31,			
	2003		2002	
	Net assets	Profit and loss account reserve	Net assets	Profit and loss account reserve
	($ million)			

Group net assets and reserve reconciliation				
As reported	77,063	38,700	70,047	32,344
SSAP 24 pension prepayment (net of deferred tax)	(4,581)	(4,581)	(2,669)	(2,669)
SSAP 24 pension provision (net of deferred tax)	3,676	3,676	2,883	2,883
FRS 17 pension asset (net of deferred tax)	1,021	1,021	221	221
FRS 17 pension liability (net of deferred tax)	(4,880)	(4,880)	(5,083)	(5,083)
Including FRS 17 pension assets and liabilities (net of deferred tax)	72,299	33,936	65,399	27,696

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 40 Pensions (continued)

Further information in respect of the Group s principal defined benefit pension plans required under FASB Statement of Financial Accounting Standards No. 132 Employers Disclosures about Pensions and Other Postretirement Benefits is set out below.

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 principals 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	60 - 80
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,			
	2003	2002	2001	2000
	(%)			
Main assumptions for the principal plans				
UK plans:				
Discount rate	5.5	5.75	6.0	6.5

Expected return on plan assets	7.0	7.0	6.0	6.5
Rate of increase in salaries	4.0	4.0	4.5	5.0
US plans:				
Discount rate	6.0	6.75	7.25	7.5
Expected return on plan assets	8.0	8.0	10.0	10.0
Rate of increase in salaries	4.0	4.0	4.0	4.0
Other plans:				
Discount rate	5.5	5.75	6.25	6.25
Expected return on plan assets	6.0	6.0	6.5	6.5
Rate of increase in salaries	4.0	4.0	3.25	3.25

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 40 Pensions (continued)

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Pension expense			
Principal plans:			
Service cost benefits earned during year	583	509	457
Interest cost on projected benefit obligation	1,581	1,452	1,432
Expected return on plan assets	(1,882)	(1,787)	(1,827)
Amortization of transition asset	(68)	(64)	(66)
Recognized net actuarial gain	(8)	(206)	(169)
Recognized prior service cost	87	77	74
Curtailment and settlement (gains) losses	4	(46)	36
Special termination benefits	92	76	175
	389	11	112
Defined contribution plans	170	153	155
Total pension expense	559	164	267

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 40 Pensions (concluded)

	UK		US		Other	
	2003	2002	2003	2002	2003	2002
			($ million)			
Benefit obligation at January 1	14,822	12,746	6,765	6,146	5,141	3,101
Service cost	290	278	177	150	116	81
Interest cost	848	773	432	421	301	256
Plan amendments			14	38		4
Curtailments, settlements and special termination benefits			(11)	75	87	(84)
Actuarial loss	796	269	1,000	672	144	350
Acquisitions				14	1	1,038
Plan participants contributions	33	29			2	2
Benefit payments	(761)	(687)	(668)	(751)	(325)	(282)
Exchange adjustment	1,738	1,414			909	675
Benefit obligation at December 31	17,766	14,822	7,709	6,765	6,376	5,141
Fair value of plan assets at January 1	15,138	16,880	4,206	5,625	1,447	1,164
Actual return on plan assets	2,692	(2,671)	1,100	(736)	96	64
Acquisitions					2	2
Plan participants contributions	33	29			2	2
Employers contributions	258	3	2,219	68	295	251
Settlement payments						
Benefit payments	(761)	(687)	(668)	(751)	(325)	(282)
Exchange adjustment	1,864	1,584			222	246
Fair value of plan assets at December 31	19,224	15,138	6,857	4,206	1,739	1,447
Funded status	1,458	316	(852)	(2,559)	(4,637)	(3,694)
Unrecognized transition (asset) obligation		(85)		(1)	37	49
Unrecognized net actuarial loss	1,532	1,766	3,918	3,699	634	489
Unrecognized prior service cost	680	691	78	72	12	10
Net amount recognized	3,670	2,688	3,144	1,211	(3,954)	(3,146)
Prepaid benefit cost (accrued benefit liability)	3,670	2,688	2,937	(2,062)	(4,225)	(3,360)
Intangible asset			14	124	29	27
Accumulated other comprehensive income			193	3,149	242	187
	3,670	2,688	3,144	1,211	(3,954)	(3,146)

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 41 Other postretirement benefits

Certain Group companies in the USA provide postretirement healthcare and life insurance benefits to their retired employees and dependants. The entitlement to these benefits is usually based on the employee remaining in service until retirement age and completion of a minimum period of service. The plans are funded to a limited extent and the accrued net liability for postretirement benefits is included within other provisions. The cost of providing postretirement benefits is assessed annually by independent actuaries using the projected unit credit method. The date of the latest actuarial valuation was January 1, 2003 and the date of the most recent actuarial review was December 31, 2003.

The assumptions used in calculating the charge for postretirement benefits are consistent with those shown in Note 40 for US pension plans.

The charge to income for postretirement benefits is as follows:

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Service cost benefits earned during year	54	37	31
Interest on postretirement benefit liabilities	259	219	187
Expected return on plan assets	(2)	(4)	(5)
Recognized net actuarial (gain) loss	112	25	(6)
Amortization of prior service cost recognized	(35)	(4)	(15)
Curtailment (gain) loss	(11)	3	(32)
Postretirement benefit expense	377	276	160

At December 31, 2003 the independent actuaries reassessed the obligation for postretirement benefits at $4,143 million ($4,326 million at December 31, 2002). The discount rate used to assess the obligation at December 31, 2003 of the plans was 6.0% (6.75% at December 31, 2002). The provision for postretirement benefits at December 31, 2003 was $2,924 million ($2,762 million at December 31, 2002).

Assumed future healthcare cost trend rate

	Years ended December 31,					
	2004	2005	2006	2007	2008	2009 and subsequent years
Beneficiaries aged under 65	11%	9%	8%	7%	6%	5%
Beneficiaries aged over 65	14%	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	One-percentage point decrease
	($ million)	
Effect on total of service and interest cost in 2004	92	(73)
Effect on postretirement obligation at December 31, 2003	561	(451)

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 41 Other postretirement benefits (continued)

BP s postretirement medical plans provide prescription drug coverage for Medicare-eligible retired employees. The Group s obligation for other postretirement benefits at December 31, 2003 does not reflect the effects of the recent US Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the 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 co-ordinate with the Medicare benefit. 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) which provides guidance on the accounting effects of the Act. The Company continues to evaluate the impact of the Act on its benefit plan design and accounting.

As indicated in Note 40 Pensions, certain additional disclosures are required by FRS 17 for the periods prior to adoption. The additional disclosures for the year ended December 31, 2003 are set out below.

	At December 31,			
	2003		2002	
	Expected long-term rate of return	Market value	Expected long-term rate of return	Market value
	(%)	($ million)	(%)	($ million)
Equities	8.5	24	8.5	24
Bonds	4.75	9	5.5	9
		33		33
Present value of plan liabilities		4,143		4,326
Other postretirement benefit liability before deferred tax		(4,110)		(4,293)
Deferred tax		1,480		1,545
		(2,630)		(2,748)

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 41 Other postretirement benefits (continued)

	At December 31,	
	2003	2002
	($ million)	
Analysis of the amount that would be charged to operating profit on an FRS 17 basis		
Current service cost	54	37
Past service cost	14	
Settlement, curtailment and special termination benefits	(669)	(78)
Total operating income	(601)	(41)
Analysis of the amount that would be charged to other finance costs on an FRS 17 basis		
Expected return on plan assets	2	4
Interest on plan liabilities	(259)	(219)
Other finance expense	(257)	(215)
Analysis of the amount that would be recognized in the statement of total recognized gains and losses on an FRS 17 basis		
Actual return less expected return on plan assets	2	(8)
Experience gains and losses arising on the plan liabilities	67	(89)
Change in assumptions underlying the present value of the plan liabilities	(443)	(1,165)
Actuarial loss recognized in statement of total recognized gains and losses	(374)	(1,262)
Movement in deficit during the year on an FRS 17 basis		
Deficit in plans at January 1	(4,293)	(3,039)
Movement in year:		
Current service cost	(54)	(37)
Past service cost	(14)	
Settlement, curtailment and special termination benefits	669	78
Acquisitions		(36)
Other finance expense	(257)	(215)
Employers contributions	213	218
Actuarial loss	(374)	(1,262)
Deficit in plans at December 31	(4,110)	(4,293)

	At December 31,

	2003	2002
History of experience gains and losses which would be recognized on an FRS 17 basis		
Difference between the expected and actual return on plan assets:		
Amount ($ million)	2	(8)
Percentage of plan assets	6%	(24)%
Experience gains and losses on plan liabilities:		
Amount ($ million)	67	(89)
Percentage of the present value of the plan liabilities	2%	(2)%
Total amount recognized in statement of total recognized gains and losses:		
Amount ($ million)	(374)	(1,262)
Percentage of the present value of the plan liabilities	(9)%	(29)%

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 41 Other postretirement benefits (concluded)

	At December 31,			
	2003		2002	
	Net assets	Profit and loss account reserve	Net assets	Profit and loss account reserve
	($ million)			
Group net assets and reserve reconciliation				
As reported	77,063	38,700	70,047	32,344
SSAP 24 other postretirement benefit provision (net of deferred tax)	1,871	1,871	1,795	1,795
FRS 17 other postretirement benefit provision (net of deferred tax)	(2,630)	(2,630)	(2,748)	(2,748)
Including FRS 17 other postretirement benefits liability (net of deferred tax)	76,304	37,941	69,094	31,391

Further information presented in compliance with the requirements of FASB Statement of Financial Accounting Standards No. 132 Employers Disclosures about Pensions and Other Postretirement Benefits is set out below.

	2003	2002
	($ million)	
Benefit obligation at January 1	4,326	3,080
Service cost	54	37
Interest cost	259	219
Plan amendments	(648)	
Settlement, curtailment and special termination benefits	(7)	(78)
Actuarial loss	376	1,254
Acquisitions		37
Benefit payments	(217)	(223)
Benefit obligation at December 31	4,143	4,326
Fair value of plan assets at January 1	33	41
Actual return on plan assets	4	(4)
Employers contributions	213	219

Benefit payments	(217)	(223)
Fair value of plan assets at December 31	33	33
Funded status	(4,110)	(4,293)
Unrecognized net actuarial loss	1,834	1,580
Unrecognized prior service cost	(648)	(49)
Provision for postretirement benefits	(2,924)	(2,762)

F - 76

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 42 Joint ventures and associated undertakings

The significant joint ventures and associated undertakings of the BP Group at December 31, 2003 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	2003 Total	2002 Total	2001 Total
			($ million)		
Turnover	1,864	1,610	3,474	1,465	1,171
Profit for the period before tax	475	360	835	288	369
Taxation	83	61	144	75	94
Profit for the period after tax	392	299	691	213	275
Fixed assets	8,389	4,778	13,167	4,026	3,904
Current assets	1,950	1,368	3,318	803	757
	10,339	6,146	16,485	4,829	4,661
Liabilities due within one year	1,575	752	2,327	284	202
Liabilities due after one year	1,350	1,434	2,784	514	598
	7,414	3,960	11,374	4,031	3,861
Minority shareholders interest	365		365		
	7,049	3,960	11,009	4,031	3,861

The joint venture TNK-BP was created on August 29, 2003. See Note 18 for further information. TNK-BP, in which BP holds a 50% interest, is an integrated oil company operating, inter alia, in Russia. The minority shareholders interest is in subsidiaries of the TNK-BP group.

The amounts shown above for TNK-BP s assets and liabilities reflect the preliminary fair value exercise undertaken in 2003. As permitted by Financial Reporting Standard No. 7 Fair Values in Acquisition Accounting , these preliminary valuations may be revised in 2004.

The results of TNK-BP for the period from August 29 to December 31, 2003 have been estimated. Any difference between the estimated and actual results for this period will be included in the results for 2004.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 42 Joint ventures and associated undertakings (continued)

Transactions between the significant joint ventures and associated undertakings and the Group are summarized below.

Sales to joint ventures and associated undertakings

		2003		2002		2001
	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	259	33	308	55	24
Pan American Energy	Crude oil	171	5	124	10	121
Watson Cogeneration	Natural gas	73	6	118	5	177
Associated undertakings						
BP Solvay Polyethylene North America (a)	Chemicals feedstocks	241	17	143	14	20
China American Petrochemical Co.	Chemicals feedstocks	240	67	117	22	92
Erdölchemie (b)	Chemicals feedstocks					250
Ruhrgas (c)	Natural gas			98		124
Samsung Petrochemical Co.	Chemicals feedstock	55	10	35	5	60

Purchases from joint ventures and associated undertakings

		2003		2002		2001
	Product	Purchases	Amount payable at December 31	Purchases	Amount payable at December 31	Purchases
		($ million)		($ million)		($ million)
Joint ventures						
BP Solvay Polyethylene Europe (a)	Chemicals feedstocks	18	14			

Pan American Energy	Crude oil	381	48	200	12	178
TNK-BP (d)	Crude oil and oil products	349	52			
Watson Cogeneration	Electricity and steam	248	12	94	10	187
Associated undertakings						
Abu Dhabi Marine Areas	Crude oil	661	61	504	55	555
Abu Dhabi Petroleum Co.	Crude oil	1,122	118	759	77	820
BP Solvay Polyethylene North America (a)	Chemicals feedstocks	11	1	7	1	
China American Petrochemical Co.	Petrochemicals	197	83	77	15	16
Erdölchemie (b)	Petrochemicals					50
Ruhrgas (c)	Natural gas			5		18
Samsung Petrochemical Co.	Chemicals feedstocks	187	38	114	6	56

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 42 Joint ventures and associated undertakings (concluded)

(a) The BP Solvay Polyethylene Europe joint venture and the BP Solvay Polyethylene North America associated undertaking were formed on November 1, 2001. The sales and purchases figures for 2001 are from November 1, 2001.

(b) The Erdölchemie sales and purchases relate to the period prior to its disposal on May 2, 2001.

(c) The Ruhrgas sales and purchases shown above relate to the period prior to its disposal on July 31, 2002.

(d) The TNK-BP purchases shown above relate to the period from August 29 to December 31, 2003.

Note 43 Contingent liabilities

There were contingent liabilities at December 31, 2003 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 case has been settled or tried to conclusion. While the amounts claimed could be substantial and 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. Consequently, BP believes that the impact of these lawsuits on the Group s results of operations, financial position or liquidity will not be material.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 43 Contingent liabilities (concluded)

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, 2003 were $20,903 million (at December 31, 2002 $19,952 million), including $20,847 million (at December 31, 2002 $19,896 million) in respect of borrowings by its subsidiary undertakings and $56 million (at December 31, 2002 $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, 2003 were $635 million (at December 31, 2002 $338 million) in respect of borrowings of joint ventures and associated undertakings and $304 million (at December 31, 2002 $237 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, 2003 amounted to $6,420 million (at December 31, 2002 $5,966 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,		
	2003	2002	2001
		($ million)	
Sales and other operating revenue	21,479	22,457	27,503
Gross profit	4,816	4,180	5,164
Profit for the year	2,597	2,049	3,105

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 45 Summarized financial information on joint ventures and associated undertakings (concluded)

	December 31, 2003	December 31, 2002
	($ million)	
Fixed and other assets	37,095	17,350
Current assets	11,972	6,895
	49,067	24,245
Current liabilities	(10,761)	(6,344)
Noncurrent liabilities	(9,813)	(6,894)
Net assets	28,493	11,007

The more important joint ventures and associated undertakings of the Group at December 31, 2003 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
Korea			
Samsung Petrochemical Co.	47	England	Petrochemicals
Taiwan			
China American Petrochemical Co.	59	Taiwan	Petrochemicals
USA			
BP Solvay Polyethylene North America	49	USA	Petrochemicals

	%	Principal place of business	Principal activities
Joint ventures			
BP Solvay Polyethylene Europe	50	Europe	Petrochemicals
CaTO Finance V Limited Partnership	50	UK	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 Company Texas (Partnership)	50	USA	Exploration and production
Watson Cogeneration	51	USA	Power generation

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 46 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	Other	Total
				($ million)					
2003									
Gross capitalized costs:									
Proved properties	25,212	4,506	43,937	10,404	3,905	9,751	1	3,260	100,976
Unproved properties	266	211	1,127	661	1,642	506	37	54	4,504
	25,478	4,717	45,064	11,065	5,547	10,257	38	3,314	105,480
Accumulated depreciation	15,346	2,912	20,024	5,067	1,890	5,516	32	1,218	52,005
Net capitalized costs	10,132	1,805	25,040	5,998	3,657	4,741	6	2,096	53,475
2002									
Gross capitalized costs:									
Proved properties	26,804	4,029	46,996	9,406	5,275	7,803		2,120	102,433
Unproved properties	294	179	1,045	806	2,148	479		236	5,187
	27,098	4,208	48,041	10,212	7,423	8,282		2,356	107,620
Accumulated depreciation	16,394	2,591	22,613	4,729	2,360	4,489		1,075	54,251
Net capitalized costs	10,704	1,617	25,428	5,483	5,063	3,793		1,281	53,369
2001									
Gross capitalized costs:									
Proved properties	23,627	2,912	42,868	8,070	5,100	6,578	1	1,739	90,895
Unproved properties	313	120	1,426	970	1,969	456	113	169	5,536
	23,940	3,032	44,294	9,040	7,069	7,034	114	1,908	96,431
Accumulated depreciation	13,320	1,883	19,508	4,047	1,910	4,134	14	875	45,691
Net capitalized costs	10,620	1,149	24,786	4,993	5,159	2,900	100	1,033	50,740

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 46 Oil and natural gas exploration and production activities (a) **(continued)**

Costs incurred for the year ended December 31

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
					($ million)				
2003									
Acquisition of properties:									
Proved									
Unproved									
Exploration and appraisal costs (b)	20	69	290	119	57	205	26	40	826
Development costs	740	236	3,486	512	42	1,614		917	7,547
Total costs	760	305	3,776	631	99	1,819	26	957	8,373
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	3,618	684	129	1,164		526	7,235
Total costs	923	291	4,088	870	290	1,325	17	639	8,443
2001									
Acquisition of properties:									
Proved								47	47
Unproved	4		20	4	155	34			217
	4		20	4	155	34		47	264
Exploration and appraisal costs (b)	109	80	295	253	68	248	7	42	1,102

Development costs	930	271	3,723	825	240	664		205	6,858
Total costs	1,043	351	4,038	1,082	463	946	7	294	8,224

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 46 Oil and natural gas exploration and production activities (a) **(continued)**

Results of operations for the year ended December 31

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
					($ million)				
2003									
Turnover (c):									
Third parties	2,257	441	1,543	1,222	421	444		777	7,105
Sales between businesses	2,901	568	11,056	2,684	925	974		1,707	20,815
	5,158	1,009	12,599	3,906	1,346	1,418		2,484	27,920
Exploration expense	17	37	204	164	15	32	21	52	542
Production costs	619	120	1,452	463	166	241		135	3,196
Production taxes	233	14	439	189	40			742	1,657
Other costs (d)	(151)	57	2,020	447	160	38	30	946	3,547
Depreciation	1,830	169	3,404	560	445	222		136	6,766
	2,548	397	7,519	1,823	826	533	51	2,011	15,708
Profit before taxation (e)	2,610	612	5,080	2,083	520	885	(51)	473	12,212
Allocable taxes	1,115	358	2,117	881	97	342	(12)	158	5,056
Results of operations	1,495	254	2,963	1,202	423	543	(39)	315	7,156
Lifting costs ($/boe)	2.7	3.1	3.2	2.2	2.4	4.1		1.6	2.8
2002									
Turnover (c):									
Third parties	2,249	465	1,321	884	457	512		644	6,532
Sales between businesses	3,169	594	7,857	1,754	905	1,015		1,278	16,572
	5,418	1,059	9,178	2,638	1,362	1,527		1,922	23,104
Exploration expense	27	47	258	167	67	50	17	11	644
Production costs	662	101	1,419	403	190	237		120	3,132
Production taxes	279	7	288	115	36			519	1,244
Other costs (d)	315	36	1,555	341	110	331	42	670	3,400
Depreciation	1,875	154	3,129	633	407	364		140	6,702
	3,158	345	6,649	1,659	810	982	59	1,460	15,122

Profit before taxation (e)	2,260	714	2,529	979	552	545	(59)	462	7,982
Allocable taxes	1,375	412	890	480	291	(86)	(18)	220	3,564
Results of operations	885	302	1,639	499	261	631	(41)	242	4,418
Lifting costs ($/boe)	2.5	2.1	2.8	2.3	2.4	3.8		1.6	2.6

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 46 Oil and natural gas exploration and production activities (a) **(continued)**

Results of operations for the year ended December 31 (continued)

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
					($ million)				
2001									
Turnover (c):									
Third parties	2,979	564	1,642	848	689	546		498	7,766
Sales between businesses	3,003	462	9,645	2,141	420	526		1,805	18,002
	5,982	1,026	11,287	2,989	1,109	1,072		2,303	25,768
Exploration expense	14	22	256	75	41	43	6	23	480
Production costs	878	91	1,379	371	148	228		168	3,263
Production taxes	559	17	384	69	36	2		581	1,648
Other costs (d)	25	33	1,749	538	148	224	58	566	3,341
Depreciation	1,353	115	3,090	535	228	130		222	5,673
	2,829	278	6,858	1,588	601	627	64	1,560	14,405
Profit before taxation (e)	3,153	748	4,429	1,401	508	445	(64)	743	11,363
Allocable taxes	1,046	306	1,463	682	167	105	1	246	4,016
Results of operations	2,107	442	2,966	719	341	340	(65)	497	7,347
Lifting costs ($/boe)	3.1	2.0	2.8	2.3	2.2	4.5		2.1	2.7

The Group s share of joint ventures and associated undertakings results of operations in 2003 was a profit of $851 million (2002 $372 million and 2001 $246 million) after deducting a tax charge of $171 million (2002 $110 million tax charge and 2001 $138 million tax charge).

The Group s share of joint ventures and associated undertakings net capitalized costs at December 31, 2003 was $10,232 million (December 31, 2002 $4,350 million and December 31, 2001 $3,325 million).

The Group s share of joint ventures and associated undertakings costs incurred in 2003 was $6,282 million (2002 $850 million and 2001 $419 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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 46 Oil and natural gas exploration and production activities (a) **(concluded)**

Results of operations for the year ended December 31 (concluded)

(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	Other	Total
					($ million)				
Year ended December 31, 2003									
Exploration and production activities									
Group (as above)	2,610	612	5,080	2,083	520	885	(51)	473	12,212
Equity-accounted entities			1	199	64		610	148	1,022
Midstream activities	279	(2)	216	211	1	1			706
Total operating profit	2,889	610	5,297	2,493	585	886	559	621	13,940
Year ended December 31, 2002									
Exploration and production activities									
Group (as above)	2,260	714	2,529	979	552	545	(59)	462	7,982
Equity-accounted entities			16	163	70	1	115	117	482
Midstream activities	266		293	138	56	(8)			745
Total operating profit	2,526	714	2,838	1,280	678	538	56	579	9,209
Year ended December 31, 2001									
Exploration and production activities									
Group (as above)	3,153	748	4,429	1,401	508	445	(64)	743	11,363

Equity-accounted entities				241	68		56	19	384
Midstream activities	271		138	92	54			53	608
Total operating profit	3,424	748	4,567	1,734	630	445	(8)	815	12,355

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 47 Business and geographical analysis

BP has four reportable operating segments Exploration and Production; Gas, Power and Renewables; Refining and Marketing; and Petrochemicals. Exploration and Production s activities include oil and natural gas exploration and field development and production (upstream activities), together with pipeline transportation and natural gas processing (midstream activities). Gas, Power and Renewables activities include marketing and trading of natural gas, natural gas liquids, new market development, LNG and solar and renewables. 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.

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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 47 Business and geographical analysis (continued)

By business

		Exploration and Production	Gas, Power and Renewables	Refining and Marketing	Petro-chemicals	Other businesses and corporate (a)	Eliminations	Total
					($ million)			
2003								
Group turnover	third parties	8,062	63,482	145,029	15,483	515		232,571
	sales between businesses (b)	23,279	1,963	4,448	592		(30,282)	
		31,341	65,445	149,477	16,075	515	(30,282)	232,571
Share of sales by joint ventures								3,474
								236,045
Equity accounted income (c)		1,186	(3)	164	73	18		1,438
Total operating profit (loss) (d)		13,940	478	2,292	623	(904)		16,429
Exceptional items (e)		913	(6)	(213)	38	99		831
Profit (loss) before interest and tax		14,853	472	2,079	661	(805)		17,260
Total assets (f)		79,344	10,260	60,088	17,649	10,231		177,572
Operating capital employed (g)		64,572	3,919	32,081	13,669	3,769		118,010
Goodwill		3,761	48	5,325	35			9,169
Depreciation and amounts provided (h)		6,950	141	2,958	751	140		10,940
Capital expenditure and acquisitions		15,452	359	3,080	775	409		20,075
2002								
Group turnover	third parties	7,197	36,037	122,470	12,507	510		178,721
	sales between businesses (b)	18,556	1,320	3,366	557		(23,799)	
		25,753	37,357	125,836	13,064	510	(23,799)	178,721
Share of sales by joint ventures								1,465
								180,186

Equity accounted income (c)		611	107	204	(10)	52		964
Total operating profit (loss) (d)		9,209	405	1,921	541	(701)		11,375
Exceptional items (e)		(726)	1,551	613	(256)	(14)		1,168
Profit (loss) before interest and tax		8,483	1,956	2,534	285	(715)		12,543
Total assets (f)		72,801	6,927	55,815	16,595	6,987		159,125
Operating capital employed (g)		62,117	2,642	31,006	12,631	490		108,886
Goodwill		4,371	55	5,969	43			10,438
Depreciation and amounts provided (h)		6,799	117	2,658	749	78		10,401
Capital expenditure and acquisitions		9,699	408	7,753	823	428		19,111
2001								
Group turnover	third parties	8,569	36,488	117,330	11,282	549		174,218
	sales between businesses (b)	19,660	2,954	2,903	233		(25,750)	
		28,229	39,442	120,233	11,515	549	(25,750)	174,218
Share of sales by joint ventures								1,171
								175,389
Equity accounted income (c)		559	184	278	99	75		1,195
Total operating profit (loss) (d)		12,355	407	1,990	(102)	(523)		14,127
Exceptional items (e)		195		471	(297)	166		535
Profit (loss) before interest and tax		12,550	407	2,461	(399)	(357)		14,662
Total assets (f)		70,017	5,775	43,553	15,098	7,527		141,970
Operating capital employed (g)		60,146	3,125	25,319	11,996	1,405		101,991
Goodwill		4,981	63	5,774	49			10,867
Depreciation and amounts provided (h)		6,043	67	2,302	588	96		9,096
Capital expenditure and acquisitions		8,861	492	2,415	1,926	430		14,124

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 47 Business and geographical analysis (continued)

By geographical area

		UK (i)	Rest of Europe	USA	Rest of World	Eliminations	Total
				($ million)			
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)	12	106	1,325		1,438
Total operating profit (d)		2,585	1,978	5,591	6,275		16,429
Exceptional items (e)		717	(151)	(347)	612		831
Profit before interest and tax		3,302	1,827	5,244	6,887		17,260
Total assets (f)		36,021	26,814	66,696	48,041		177,572
Operating capital employed (g)		20,611	11,919	49,444	36,036		118,010
Depreciation and amounts provided (h)		2,963	1,028	5,187	1,762		10,940
Capital expenditure and acquisitions		1,619	1,277	6,291	10,888		20,075
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
							180,186
Equity accounted income (c)		(4)	130	153	685		964
Total operating profit (d)		1,784	1,986	3,458	4,147		11,375
Exceptional items (e)		(88)	1,817	(242)	(319)		1,168

Profit before interest and tax		1,696	3,803	3,216	3,828		12,543
Total assets (f)		33,016	25,012	63,982	37,115		159,125
Operating capital employed (g)		20,949	11,877	48,256	27,804		108,886
Depreciation and amounts provided (h)		2,821	867	4,780	1,933		10,401
Capital expenditure and acquisitions		1,637	6,556	6,095	4,823		19,111
2001							
Group turnover	third parties (j)	34,151	29,098	83,757	27,212		174,218
	sales between areas	13,467	7,603	939	6,699	(28,708)	
		47,618	36,701	84,696	33,911	(28,708)	174,218
Share of sales by joint ventures		13	30	318	810		1,171
							175,389
Equity accounted income (c)		8	232	263	692		1,195
Total operating profit (d)		2,443	1,370	5,882	4,432		14,127
Exceptional items (e)		(319)	33	289	532		535
Profit before interest and tax		2,124	1,403	6,171	4,964		14,662
Total assets (f)		29,951	15,287	63,150	33,582		141,970
Operating capital employed (g)		19,477	7,346	45,188	29,980		101,991
Depreciation and amounts provided (h)		2,159	513	4,937	1,487		9,096
Capital expenditure and acquisitions		2,128	1,787	6,160	4,049		14,124

F - 89

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 47 Business and geographical analysis (concluded)

(a) Other businesses and corporate comprises Finance, the Group s coal asset and aluminium asset, its investment in PetroChina and Sinopec, interest income and costs relating to corporate activities worldwide.

(b) Sales and transfers between businesses are made at 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, 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 $831 million in 2003 (2002 $1,168 million profit and 2001 $535 million profit).

(f) Total assets comprise fixed and current assets and include investments in joint ventures and associated undertakings analyzed between activities as follows:

	Exploration and Production	Gas, Power and Renewables	Refining and Marketing	Petro-chemicals	Other businesses and corporate (a)	Total
			($ million)			
2003	12,509	267	1,081	1,691	27	15,575
2002	5,687	210	1,452	1,252	56	8,657
2001	5,326	857	1,675	1,416	20	9,294

(g) Operating capital employed comprises net assets before deducting finance debt and liabilities for current and deferred taxation.

(h) Depreciation consists of charges for depreciation, depletion and amortization of property, plant and equipment, exploration expense and amounts provided against fixed asset investments.

(i) 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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

(a) Group consolidation (concluded)

The following summarizes the reclassifications for joint ventures and associated undertakings necessary to accord with US GAAP.

	Year ended December 31, 2003		
Increase (decrease) in caption heading	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	851	(134)	717
Taxation	5,972	(224)	5,748
Profit for the year	10,267		10,267

	Year ended December 31, 2002		
Increase (decrease) in caption heading	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	1,279	(141)	1,138
Taxation	4,342	(262)	4,080
Profit for the year	6,845		6,845

	Year ended December 31, 2001		
Increase (decrease) in caption heading	As reported	Reclassification	US GAAP presentation
		($ million)	
Consolidated statement of income			
Other income	694	691	1,385

Share of profits of JVs and associated undertakings	1,195	(1,195)	
Exceptional items before taxation	535	2	537
Interest expense	1,670	(205)	1,465
Taxation	6,375	(297)	6,078
Profit for the year	6,556		6,556

(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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

(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. Under US GAAP the deferred tax asset or liability is amortized over the same period as the assets and liabilities to which it relates.

The adjustments to profit for the year and to BP shareholders interest to accord with US GAAP are summarized below.

Increase (decrease) in caption heading	Years ended December 31, 2003	2002	2001
	($ million)		
Cost of sales	1,550	852	1,091
Taxation	(1,583)	(537)	(276)
Profit (loss) for the year	33	(315)	(815)

	At December 31, 2003	2002
	($ million)	
Tangible assets	6,084	7,408
Deferred taxation	6,149	7,486
BP shareholders interest	(65)	(78)

The major components of deferred tax liabilities and assets on a US GAAP basis were as follows:

December 31,

	2003	2002
	($ million)	
Depreciation	(21,832)	(22,472)
Other taxable temporary differences	(3,715)	(2,731)
Total deferred tax liabilities	(25,547)	(25,203)
Petroleum revenue tax	601	567
Decommissioning and other provisions	2,743	4,956
Tax credit and loss carry forward	1,607	1,823
Other deductible temporary differences	222	423
Gross deferred tax assets	5,173	7,769
Valuation allowance	(1,502)	(1,726)
Net deferred tax assets	3,671	6,043
Net deferred tax liability*	(21,876)	(19,160)

* Primarily noncurrent.

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

(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 interest expense in the period. When a decommissioning provision is set up, a tangible fixed asset of the same amount is also recognized and is subsequently depreciated as part of the capital costs of the facilities.

On January 1, 2003 the Group adopted Statement of Financial Accounting Standards No. 143 Accounting for Asset Retirement Obligations (SFAS 143). SFAS 143 requires companies to record liabilities equal to the fair value of their asset retirement obligations when they are incurred (typically when the asset is installed at the production location). When the liability is initially recorded, companies capitalize an equivalent amount as part of the cost of the asset. Over time the liability is accreted for the change in its present value each period, and the initial capitalized cost is depreciated over the useful life of the related asset. 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.

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,		
	2003	2002	2001
	($ million)		

Cost of sales	188	334	523
Interest expense	(173)	(212)	(238)
Taxation	(64)	(130)	(103)
Profit (loss) for the period before cumulative effect of accounting change	49	8	(182)
Cumulative effect of accounting change, net of taxation	1,002		
Profit (loss) for the year	1,051	8	(182)

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

(d) Provisions (continued)

	At December 31, 2003	At December 31, 2002
	($ million)	
Tangible assets	(835)	(1,297)
Provisions	(636)	412
Deferred taxation	(71)	(621)
BP shareholders interest	(128)	(1,088)

The following data summarizes the movements in the asset retirement obligation, as adjusted to accord with US GAAP, for the year ended December 31, 2003.

	($ million)
At January 1, 2003	3,474
Exchange adjustments	219
New provisions	855
Unwinding of discount	187
Utilized/deleted	(863)
At December 31, 2003	3,872

The following pro forma data summarize the results of operations assuming SFAS 143 was applied retroactively with effect from January 1, 2001 for the three years ended December 31, 2003, 2002 and 2001:

	Years ended December 31, 2003 (a)	2002	2001
	($ million)		
Profit for the period applicable to ordinary shares as adjusted to accord with US GAAP			
As reported	13,141	8,395	4,162

Pro forma	12,139	8,405	4,179
Per ordinary share cents			
Basic as reported	59.27	37.48	18.55
Basic pro forma	54.75	37.53	18.63
Diluted as reported	58.70	37.30	18.44
Diluted pro forma	54.23	37.35	18.51
Per American Depositary Share cents			
Basic as reported	355.62	224.88	111.30
Basic pro forma	328.50	225.18	111.78
Diluted as reported	352.20	223.80	110.64
Diluted pro forma	325.38	224.10	111.06

(a) Pro forma data for the year ended December 31, 2003 excludes the cumulative effect of adoption.

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

(d) Provisions (concluded)

The pro forma asset retirement obligation at January 1, 2002 and December 31, 2002, assuming SFAS 143 was applied retroactively with effect from January 1, 2001 amounts to $3,268 million and $3,469 million, respectively.

(e) 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 only permitted to be made within 12 months of the acquisition date.

In 2001, a revision of $911 million was made to the previously reported fair values for tangible fixed assets relating to the 2000 acquisition of Atlantic Richfield. Under US GAAP, the revision was included in cost of sales.

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 (g) Goodwill and intangible assets.

Increase (decrease) in caption heading	Years ended December 31,		
	2003	2002	2001
		($ million)	
Cost of sales	(330)		1,150
Taxation	41		(239)
Profit for the year	289		(911)

(f) 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 was not recognized immediately but amortized over the term of the operating lease.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

(f) Sale and leaseback (concluded)

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, 2003	2002	2001
	($ million)		
Cost of sales	(106)	(40)	51
Taxation	37	16	(15)
Profit (loss) for the year	69	24	(36)

	At December 31, 2003	2002
	($ million)	
Tangible assets		161
Other accounts payable and accrued liabilities	24	27
Provisions	32	(117)
Finance debt		413
Deferred taxation	(19)	(56)
BP shareholders interest	(37)	(106)

(g) 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.

On January 1, 2002 the Group adopted Statement of Financial Accounting Standards No. 142 Goodwill and Other Intangible Assets (SFAS 142) for US GAAP reporting. This standard eliminates the requirement to amortize goodwill and indefinite lived intangible assets. Rather, such assets are subject to periodic impairment testing. Intangible assets that are not deemed to have an indefinite life continue to be amortized over their estimated useful lives. Prior to the adoption of SFAS 142, goodwill was amortized over the same useful economic life for both UK and US GAAP. Amortization of goodwill charged to income under UK GAAP has been reversed for US GAAP. The Group does not have any other intangible assets with indefinite lives.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

(g) Goodwill and intangible assets (continued)

During the second quarter of 2003 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.

Increase (decrease) in caption heading	Years ended December 31,		
	2003	2002	2001
		($ million)	
Cost of sales	(1,376)	(1,302)	(60)
Taxation			
Profit for the year	1,376	1,302	60

	At December 31,	
	2003	2002
	($ million)	
Intangible assets	1,669	(84)
Deferred taxation		
BP shareholders interest	1,669	(84)

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

(g) Goodwill and intangible assets (continued)

Profit for the year, as adjusted to accord with US GAAP, to exclude amortization of goodwill no longer being amortized pursuant to SFAS 142 is shown below.

	Year ended December 31, 2001
	($ million)
Profit for the year applicable to ordinary shares as adjusted to accord with US GAAP, as reported	4,162
Add back goodwill amortization	1,228
Profit for the year as adjusted to accord with US GAAP, as adjusted	5,390
Per ordinary share cents	
Basic as reported	18.55
Adjustment	5.47
Basic as adjusted	24.02
Diluted as reported	18.44
Adjustment	5.44
Diluted as adjusted	23.88
Per American Depositary Share cents	
Basic as reported	111.30
Adjustment	32.82
Basic as adjusted	144.12
Diluted as reported	110.64
Adjustment	32.64
Diluted as adjusted	143.28

The Group s licence and property acquisition costs included within Exploration expenditure, and other intangible assets have finite lives. These assets are amortized on a straight-line basis over their estimated useful economic lives for both UK and US GAAP. The carrying amounts included within Exploration expenditure for licence and property acquisition costs at December 31, 2003 were $599 million. The remaining elements of Exploration expenditure are accounted for both UK and US GAAP as described in our accounting policy in Note 1.

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

(g) Goodwill and intangible assets (concluded)

Changes to exploration expenditure, goodwill and other intangible assets, as adjusted to accord with US GAAP, during the years ended December 31, 2002 and 2003 are shown below.

	Exploration expenditure	Goodwill	Gain arising on asset exchange (see (i))	Additional minimum pension liability (see (m))	Other intangibles	Total
	($ million)					
Net book amount						
At January 1, 2002	5,334	9,453	188	112	288	15,375
Amortization expense	(385)		(21)		(168)	(574)
Acquisitions		545				545
Other movements	(5)	356		38	64	453
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 December 31, 2003	4,236	10,838	148	43	237	15,502

Amortization expense relating to other intangibles is expected to be in the range $50-$75 million in each of the succeeding five years.

(h) Derivative financial instruments and hedging activities

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

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

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 SFAS 133. For these derivatives, the cumulative effect of adopting SFAS 133 resulted in a pre-tax charge to income, as adjusted to accord with US GAAP, of $27 million ($18 million after tax) in the year ended December 31, 2001. Under US GAAP the fair values of derivative financial instruments are shown as current assets and liabilities as appropriate.

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

(h) Derivative financial instruments and hedging activities (continued)

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. The cumulative effect of adopting SFAS 133 for these derivatives resulted in a pre-tax charge to income, as adjusted to accord with US GAAP, of $530 million ($344 million after tax) in the year ended December 31, 2001.

In October 2002, the FASB Emerging Issues Task Force (EITF) reached a consensus which rescinded EITF Issue No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities (EITF 98-10). As a result of this consensus, all energy-related, non-derivative contracts (such as transportation, storage, tolling, and requirements contracts that do not meet the definition of a derivative) and trading inventories that are accounted for at fair value pursuant to EITF 98-10 are no longer accounted for at fair value upon application of the consensus. Rather, such contracts are accounted for as executory contracts on an accruals basis.

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.

Also, 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). Under this consensus, trading inventories are recorded on the balance sheet at historical cost. The Group marks trading inventories to market at the balance sheet date. Thus 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,		
	2003	2002	2001
		($ million)	
Cost of sales	(27)	(842)	481
Taxation	15	302	(168)
Profit (loss) for the year before cumulative effect of accounting change	12	540	(313)
Cumulative effect of accounting change, net of taxation	50		(362)
Profit (loss) for the year	62	540	(675)

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

(h) Derivative financial instruments and hedging activities (concluded)

	At December 31,	
	2003	2002
	($ million)	
Inventories	(150)	(209)
Accounts payable and accrued liabilities	(58)	(13)
Deferred taxation	(20)	(61)
BP shareholders interest	(72)	(135)

(i) 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).

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,		
	2003	2002	2001
		($ million)	
Profit on sale of fixed assets and businesses or termination of operations			242
Cost of sales	25	27	
Taxation	(8)	(9)	85
Profit for the year	(17)	(18)	157

	At December 31,

	2003	2002
	($ million)	
Intangible assets	148	167
Accounts payable and accrued liabilities	(51)	(52)
Deferred taxation	70	77
BP shareholders interest	129	142

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

(j) Ordinary shares held for future awards to employees

Under UK GAAP, Company shares held by an Employee Share Ownership Plan to meet future requirements of employee share schemes are recorded in the balance sheet as Fixed assets Investments. Under US GAAP, such shares are recorded in the balance sheet as a reduction of shareholders interest.

The adjustment to BP shareholders interest to accord with US GAAP is shown below.

	At December 31,	
Increase (decrease) in caption heading	2003	2002
	($ million)	
Fixed assets Investments	(96)	(159)
BP shareholders interest	(96)	(159)

(k) 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	2003	2002
	($ million)	
Other accounts payable and accrued liabilities	(1,495)	(1,398)
BP shareholders interest	1,495	1,398

(l) 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. The increase in the year ended December 31, 2003 relates primarily to the Group s investments in PetroChina and Sinopec. The Group sold these investments in January and February 2004, respectively.

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 2003 gains of $99 million were reclassified from comprehensive income to net income.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

(l) Investments (concluded)

The adjustment to BP shareholders interest to accord with US GAAP is shown below.

Increase (decrease) in caption heading	At December 31, 2003	2002
	($ million)	
Fixed assets Investments	1,924	52
Deferred taxation	673	18
BP shareholders interest	1,251	34

(m) Additional minimum pension liability

Where a pension plan has an unfunded accumulated benefit obligation, US GAAP requires such amount to be recognized as a liability in the balance sheet. The adjustment resulting from the recognition of any such minimum liability, including the elimination of amounts previously recognized as a prepaid benefit cost, is reported as an intangible asset to the extent of unrecognized prior service cost with the remaining amount reported in comprehensive income.

The adjustments to accumulated other comprehensive income (BP shareholders interest) to accord with US GAAP are summarized below.

Increase (decrease) in caption heading	At December 31, 2003	2002
	($ million)	
Intangible assets	43	150
Other receivables falling due after more than one year		(1,211)
Noncurrent liabilities accounts payable and accrued liabilities	478	2,276
Deferred taxation	(158)	(1,173)
BP shareholders interest	(277)	(2,164)

(n) Balance sheet

Under US GAAP Other receivables due after one year of $9,332 million at December 31, 2003 ($6,245 million at December 31, 2002), included within current assets, would have been classified as noncurrent assets. Borrowing under US Industrial Revenue/Municipal Bonds of $2,503 million ($1,881 million at December 31, 2002) 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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

The following is a summary of the adjustments to profit for the year and to BP shareholders interest which would be required if generally accepted accounting principles in the 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,		
	2003	2002	2001
	($ million except per share amounts)		
Profit as reported in the consolidated statement of income	10,267	6,845	6,556
Deferred taxation/business combinations (c)	33	(315)	(815)
Provisions (d)	49	8	(182)
Revisions to fair market values (e)	289		(911)
Sale and leaseback (f)	69	24	(36)
Goodwill and intangible assets (g)	1,376	1,302	60
Derivative financial instruments (h)	12	540	(313)
Gain arising on asset exchange (i)	(17)	(18)	157
Other	13	11	10
Profit for the year before cumulative effect of accounting changes as adjusted to accord with US GAAP	12,091	8,397	4,526
Cumulative effect of accounting changes:			
Provisions (d)	1,002		
Derivative financial instruments (h)	50		(362)
Profit for the year as adjusted to accord with US GAAP	13,143	8,397	4,164
Dividend requirements on preference shares	2	2	2
Profit for the year applicable to ordinary shares as adjusted to accord with US GAAP	13,141	8,395	4,162
Profit for the year as adjusted:			

Per ordinary share cents			
Basic before cumulative effect of accounting changes	54.53	37.48	20.16
Cumulative effect of accounting changes	4.74		(1.61)
	59.27	37.48	18.55
Diluted before cumulative effect of accounting changes	54.01	37.30	20.04
Cumulative effect of accounting changes	4.69		(1.60)
	58.70	37.30	18.44
Per American Depositary Share - cents (ii)			
Basic before cumulative effect of accounting changes	327.18	224.88	120.96
Cumulative effect of accounting changes	28.44		(9.66)
	355.62	224.88	111.30
Diluted before cumulative effect of accounting changes	324.06	223.80	120.24
Cumulative effect of accounting changes	28.14		(9.60)
	352.20	223.80	110.64

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

BP shareholders interest

	December 31,	
	2003	2002
	($ million)	
BP shareholders interest as reported in the consolidated balance sheet	75,938	69,409
Deferred taxation/business combinations (c)	(65)	(78)
Provisions (d)	(128)	(1,088)
Sale and leaseback (f)	(37)	(106)
Goodwill and intangible assets (g)	1,669	(84)
Derivative financial instruments (h)	(72)	(135)
Gain arising on asset exchange (i)	129	142
Ordinary shares held for future awards to employees (j)	(96)	(159)
Dividends (k)	1,495	1,398
Investments (l)	1,251	34
Additional minimum pension liability (m)	(277)	(2,164)
Other	(43)	(48)
BP shareholders interest as adjusted to accord with US GAAP	79,764	67,121

(i) The profit reported under UK GAAP for the year ended December 31, 2001 has been restated to reflect the adoption of FRS 19. Consequently certain of the adjustments in the UK/US GAAP reconciliation have also been restated. Profit and BP shareholders interest, as adjusted to accord with US GAAP, are unaffected by the adoption of FRS 19.

(ii) 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,

	2003	2002	2001
		($ million)	
Profit for the period as adjusted to accord with US GAAP	13,143	8,397	4,164
Currency translation differences	3,841	3,333	(828)
Investments			
Unrealized gains	1,316	84	110
Unrealized losses		(48)	
Less: reclassification adjustment for gains included in net income	(99)		
Additional minimum pension liability	1,887	(1,222)	(797)
Comprehensive income	20,088	10,544	2,649

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

Accumulated other comprehensive income at December 31, 2003 comprised currency translation gains of $2,464 million (losses $1,377 million at December 31, 2002), pension liability adjustments of $277 million ($2,164 million at December 31, 2002) and net unrealized gains on investments of $1,251 million ($34 million gain at December 31, 2002).

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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

The statement of consolidated cash flows presented in accordance with SFAS 95 is as follows:

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Operating activities			
Profit after taxation	10,437	6,922	6,617
Adjustments to reconcile profit after tax to net cash provided by operating activities			
Depreciation and amounts provided	10,940	10,401	8,858
Exploration expenditure written off	297	385	238
Share of profits of joint ventures and associated undertakings less dividends received	(532)	3	(60)
(Profit) loss on sale of businesses and fixed assets	(831)	(1,166)	(537)
Working capital movement (a)	(4,953)	(1,416)	1,319
Deferred taxation	1,053	1,194	1,244
Other	530	(280)	(111)
Net cash provided by operating activities	16,941	16,043	17,568
Investing activities			
Capital expenditures	(12,630)	(12,216)	(12,295)
Acquisitions, net of cash acquired	(211)	(4,324)	(1,210)
Acquisition of investment in TNK-BP joint venture	(2,351)		
Investment in associated undertakings	(987)	(971)	(586)
Net investment in joint ventures	(178)	(354)	(497)
Proceeds from disposal of assets	6,432	6,782	2,903
Net cash used in investing activities	(9,925)	(11,083)	(11,685)
Financing activities			
Proceeds from shares issued (repurchased)	(1,826)	(555)	(1,100)
Proceeds from long-term financing	4,322	3,707	1,296
Repayments of long-term financing	(3,560)	(2,369)	(2,602)
Net (decrease) increase in short-term debt	(2)	(602)	1,434
Dividends paid BP shareholders	(5,654)	(5,264)	(4,827)
Minority shareholders	(20)	(40)	(54)
Net cash used in financing activities	(6,740)	(5,123)	(5,853)
Currency translation differences relating to cash and cash equivalents	121	90	(53)

Increase (decrease) in cash and cash equivalents	397	(73)	(23)
Cash and cash equivalents at beginning of year	1,735	1,808	1,831
Cash and cash equivalents at end of year	2,132	1,735	1,808

(a) Working capital:

Inventories (increase) decrease	(841)	(1,521)	1,490
Receivables (increase) decrease	(5,611)	(2,750)	1,905
Current liabilities excluding finance debt increase (decrease)	1,499	2,855	(2,076)
	(4,953)	(1,416)	1,319

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

Impact of new US accounting standards

Guarantees: In November 2002, the FASB issued FASB Interpretation No. 45 Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others (Interpretation 45). Interpretation 45 elaborates on existing disclosure requirements for guarantees and clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. The initial recognition and measurement provisions of Interpretation 45 apply on a prospective basis to guarantees issued or modified after December 31, 2002. The adoption of Interpretation 45 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.

Consolidation: 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 adoption of Interpretation 46 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.

The Company currently has several ships under construction which will be 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. At December 31, 2003 consolidation of these entities would result in an increase in tangible assets and finance debt of $217 million. 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.

Financial instruments: In April 2003, the FASB issued Statement of Financial Accounting Standards No. 149 Amendment of Statement 133 on Derivative Instruments and Hedging Activities (SFAS 149). SFAS 149 amends and clarifies the financial accounting and reporting of derivative instruments and hedging activities under SFAS 133. SFAS 149 applies to contracts entered into or modified after June 30, 2003, and hedging relationships designated after June 30, 2003.

In May 2003, the FASB issued Statement of Financial Accounting Standards No. 150 Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity (SFAS 150). SFAS 150 establishes standards for classifying and measuring certain financial instruments that have characteristics of both liabilities and equity. SFAS 150 applies to instruments entered into or modified after May 31, 2003. For instruments existing at May 31, 2003, SFAS 150 is effective for accounting periods beginning after June 15, 2003.

The adoption of SFAS 149 and SFAS 150 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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

Impact of new US accounting standards (continued)

Tangible assets: The Securities and Exchange Commission requested the FASB to consider whether oil and natural gas mineral rights held under lease or other contractual arrangement should be classified on the balance sheet as a tangible asset (property, plant and equipment) or as an intangible asset (exploration expenditure). At its March 2004 meeting, the EITF reached a consensus on Issue No. 04-2, (Whether Mineral Rights are Tangible or Intangible Assets) that all mineral rights should be considered tangible assets for accounting purposes. In April 2004, the FASB issued FASB Staff Position Nos. FAS 141-1 and FAS 142-1 (Interaction of FASB Statements No. 141, Business Combinations, and No. 142, Goodwill and Other Intangible Assets, and EITF Issue No. 04-2, Whether Mineral Rights are Tangible or Intangible Assets), which amended SFAS 141 and 142 to remove mineral rights as an example of an intangible asset consistent with the EITF s consensus. The EITF consensus and the FASB Staff Position are effective for reporting periods beginning after April 29, 2004.

In accordance with Group accounting practice, exploration licence acquisition costs are initially capitalized 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, 2003, exploration licence acquisition costs included in the Group s intangible fixed assets and tangible fixed assets, net of accumulated amortization, amounted to approximately $600 million and $1.3 billion, respectively.

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 FRS17. This change in accounting policy results in a prior year adjustment. Upon adoption, shareholders funds at January 1, 2003 have been reduced by $5,601 million, profit for the year 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 increased (decreased) by $(7,829) million and $76 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 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

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 48 US generally accepted accounting principles (continued)

Impact of new UK accounting standards adopted in 2004 (concluded)

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 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 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 December 31, 2003 by $96 million; the impact on profit before taxation for 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, which automatically becomes law in all EU countries, requires all EU companies listed on a 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 published 15 revised standards in December 2003, and the remaining standards of its stable platform on March 31, 2004. The stable platform is the set of IFRS to be adopted on a mandatory basis in 2005. A process of endorsement of IFRS has been established by the EU for completion in due time to allow adoption by companies in 2005, but objections to certain IFRS by certain EU member states may disrupt this process.

BP has established a project team involving representatives of businesses and functions to plan for and achieve a smooth transition to IFRS. The project team is looking at all implementation aspects, including changes to accounting policies, systems impacts and the wider business issues that may arise from such a fundamental change. We currently expect that the Group will be fully prepared for the transition in 2005.

The Group has not yet determined the full effects of adopting IFRS. Our preliminary view is that the major differences between our current accounting practice and IFRS will be in respect of hedge accounting, accounting for embedded derivatives and other items falling within the scope of the financial instruments standards, accounting for business combinations, deferred tax and share-based payments.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 49 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, 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		203,862	(3,269)	202,029
Production taxes	242		1,481		1,723
Gross profit	1,490		27,228	101	28,819
Distribution and administration expenses	4	99	13,969		14,072
Exploration expense	15		528	(1)	542
	1,471	(99)	12,731	102	14,205
Other income	21	1,413	291	(939)	786
Group operating profit	1,492	1,314	13,022	(837)	14,991
Share of profits of joint ventures			924		924
Share of profits of associated undertakings			514		514
Equity-accounted income of subsidiaries	421	15,783		(16,204)	

Total operating profit	1,913	17,097	14,460	(17,041)	16,429
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	17,943	15,292	(17,887)	17,260
Interest expense	299	1,689	1,472	(2,609)	851
Profit before taxation	1,613	16,254	13,820	(15,278)	16,409
Taxation	741	5,972	5,310	(6,051)	5,972
Profit after taxation	872	10,282	8,510	(9,227)	10,437
Minority shareholders interest			170		170
Profit for the year	872	10,282	8,340	(9,227)	10,267

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 49 Condensed consolidating information on certain US Subsidiaries (continued)

Income statement (continued)

The following is a summary of the adjustments to the profit for the period which would be required if generally accepted accounting principles in the United States (US GAAP) had been applied instead of those generally accepted in the United Kingdom.

	Issuer	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	10,282	8,340	(9,227)	10,267
Adjustments:					
Deferred taxation/business combinations	(12)	33	53	(41)	33
Provisions	(5)	49	90	(85)	49
Revisions to fair market values		289	289	(289)	289
Sale and leaseback		69	69	(69)	69
Goodwill		1,376	1,376	(1,376)	1,376
Derivative financial instruments	(13)	12	12	(12)	12
Gain arising on asset exchange		(17)	(17)	17	(17)
Other		13	13		13
Profit for the year before cumulative effect of accounting change as adjusted to accord with US GAAP	842	12,106	10,225	(11,082)	12,091
Cumulative effect of accounting change:					
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	13,158	11,063	(12,141)	13,143

F - 113

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 49 Condensed consolidating information on certain US Subsidiaries (continued)

Income statement (continued)

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc	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	(1,129)	155,389	(1,309)	154,401
Production taxes	199		1,075		1,274
Gross profit	707	1,129	22,193	(983)	23,046
Distribution and administration expenses	12	997	11,623		12,632
Exploration expense	18		610	16	644
	677	132	9,960	(999)	9,770
Other income	31	752	446	(588)	641
Group operating profit	708	884	10,406	(1,587)	10,411
Share of profits of joint ventures			347		347
Share of profits of associated undertakings			617		617
Equity-accounted income of subsidiaries	283	10,847		(11,130)	
Total operating profit	991	11,731	11,370	(12,717)	11,375
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	13,841	12,542	(14,827)	12,543
Interest expense	93	1,712	1,602	(2,128)	1,279
Profit before taxation	894	12,129	10,940	(12,699)	11,264

Taxation	344	4,342	4,065	(4,409)	4,342
Profit after taxation	550	7,787	6,875	(8,290)	6,922
Minority shareholders interest			77		77
Profit for the year	550	7,787	6,798	(8,290)	6,845

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 49 Condensed consolidating information on certain US Subsidiaries (continued)

Income statement (continued)

The following is a summary of the adjustments to the profit for the period which would be required if generally accepted accounting principles in the United States (US GAAP) had been applied instead of those generally accepted in the United Kingdom.

	Issuer	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	7,787	6,798	(8,290)	6,845
Adjustments:					
Deferred taxation/business combinations	(129)	(315)	(232)	361	(315)
Provisions	(1)	8	9	(8)	8
Sale and leaseback		24	24	(24)	24
Goodwill		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)
Other		11	11	(11)	11
Profit for the year as adjusted to accord with US GAAP	370	9,339	8,434	(9,746)	8,397

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 49 Condensed consolidating information on certain US Subsidiaries (continued)

Income statement (continued)

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
			($ million)		
Year ended December 31, 2001					
Turnover	1,919		175,389	(1,919)	175,389
Less: Joint ventures			1,171		1,171
Group turnover	1,919		174,218	(1,919)	174,218
Cost of sales	982	1,900	149,969	(3,958)	148,893
Production taxes	192		1,497		1,689
Gross profit	745	(1,900)	22,752	2,039	23,636
Distribution and administration expenses	5	846	10,067		10,918
Exploration expense	55		425		480
	685	(2,746)	12,260	2,039	12,238
Other income	1	1,365	668	(1,340)	694
Group operating profit	686	(1,381)	12,928	699	12,932
Share of profits of joint ventures			439		439
Share of profits of associated undertakings			756		756
Equity-accounted income of subsidiaries	552	16,665		(17,217)	
Total operating profit	1,238	15,284	14,123	(16,518)	14,127
Profit (loss) on sale of businesses or termination of operations		(68)			(68)
Profit (loss) on sale of fixed assets	1	601	758	(757)	603
Profit before interest and tax	1,239	15,817	14,881	(17,275)	14,662
Interest expense	101	2,886	2,901	(4,218)	1,670
Profit before taxation	1,138	12,931	11,980	(13,057)	12,992
Taxation	478	6,375	6,285	(6,763)	6,375

Profit after taxation	660	6,556	5,695	(6,294)	6,617
Minority shareholders interest			61		61
Profit for the year	660	6,556	5,634	(6,294)	6,556

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 49 Condensed consolidating information on certain US Subsidiaries (continued)

Income statement (concluded)

The following is a summary of the adjustments to the profit for the period which would be required if generally accepted accounting principles in the United States (US GAAP) had been applied instead of those generally accepted in the United Kingdom.

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
		($ million)			
Year ended December 31, 2001					
Profit as reported	660	6,556	5,634	(6,294)	6,556
Adjustments:					
Deferred taxation/business combinations	(60)	(815)	(850)	910	(815)
Provisions	(5)	(182)	(179)	184	(182)
Impairment		(911)	(911)	911	(911)
Sale and leaseback		(36)	(36)	36	(36)
Goodwill		60	60	(60)	60
Derivative financial instruments		(313)	(313)	313	(313)
Gain arising on asset exchange		157	157	(157)	157
Other		10	10	(10)	10
Profit for the year before cumulative effect of accounting change as adjusted to accord with US GAAP	595	4,526	3,572	(4,167)	4,526
Cumulative effect of accounting change:					
Derivative financial instruments		(362)	(362)	362	(362)
Profit for the year as adjusted to accord with US GAAP	595	4,164	3,210	(3,805)	4,164

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 49 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, 2003					
Fixed assets					
Intangible assets	424		13,218		13,642
Tangible assets	6,432		85,479		91,911
Investments					
Joint ventures			11,009		11,009
Associated undertakings		2	4,868		4,870
Other		96	1,579		1,675
Subsidiaries equity accounted basis	2,814	81,022		(83,836)	
	2,814	81,120	17,456	(83,836)	17,554
Total fixed assets	9,670	81,120	116,153	(83,836)	123,107
Current assets					
Inventories	102		11,515		11,617
Receivables amounts falling due:					
Within one year	9,846	865	36,208	(15,535)	31,384
After more than one year	1,368	27,105	10,213	(29,354)	9,332
Investments			185		185
Cash at bank and in hand	(5)	3	1,949		1,947
	11,311	27,973	60,070	(44,889)	54,465
Current liabilities amounts falling due within one year					
Finance debt	55		9,401		9,456
Other payables	1,541	6,746	48,376	(15,535)	41,128
Net current assets (liabilities)	9,715	21,227	2,293	(29,354)	3,881
Total assets less current liabilities	19,385	102,347	118,446	(113,190)	126,988

Noncurrent liabilities					
Finance debt			12,869		12,869
Other payables	4,272	50	31,122	(29,354)	6,090
Provisions for liabilities and charges					
Deferred taxation	1,745		13,528		15,273
Other	569	216	14,908		15,693
Net assets	12,799	102,081	46,019	(83,836)	77,063
Minority shareholders interest equity			1,125		1,125
BP Shareholders interest	12,799	102,081	44,894	(83,836)	75,938

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 49 Condensed consolidating information on certain US Subsidiaries (continued)

Balance Sheet (continued)

	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
Retained earnings	7,751	65,540	44,197	(78,788)	38,700
	12,799	102,081	44,894	(83,836)	75,938

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	12,799	102,081	44,894	(83,836)	75,938
Adjustments:					

Deferred taxation/business combinations	62	(65)	(127)	65	(65)
Provisions	27	(128)	(155)	128	(128)
Sale and leaseback		(37)	(37)	37	(37)
Goodwill		1,669	1,669	(1,669)	1,669
Derivative financial instruments	(63)	(72)	(72)	135	(72)
Gain arising on asset exchange		129	129	(129)	129
Ordinary shares held for future awards to employees		(96)			(96)
Dividends		1,495			1,495
Investments		1,251	1,251	(1,251)	1,251
Additional minimum pension liability		(277)	(277)	277	(277)
Other		(43)	19	(19)	(43)
BP Shareholders interest as adjusted to accord with US GAAP	12,825	105,907	47,294	(86,262)	79,764

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 49 Condensed consolidating information on certain US Subsidiaries (continued)

Balance Sheet (continued)

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
			($ million)		
At December 31, 2002					
Fixed assets					
Intangible assets	427		15,139		15,566
Tangible assets	6,405		81,277		87,682
Investments					
Joint ventures			4,031		4,031
Associated undertakings		3	4,623		4,626
Other		159	1,995		2,154
Subsidiaries equity accounted basis	2,561	91,939		(94,500)	
	2,561	92,101	10,649	(94,500)	10,811
Total fixed assets	9,393	92,101	107,065	(94,500)	114,059
Current assets					
Inventories	102		10,079		10,181
Receivables amounts falling due:					
Within one year	215	1,892	36,700	(11,902)	26,905
After more than one year	17,954	11,689	14,322	(37,720)	6,245
Investments			215		215
Cash at bank and in hand	(11)	1	1,530		1,520
	18,260	13,582	62,846	(49,622)	45,066
Current liabilities amounts falling due within one year					
Finance debt	1,768		10,031	(1,713)	10,086
Other payables	1,129	9,906	35,369	(10,189)	36,215

Net current assets (liabilities)	15,363	3,676	17,446	(37,720)	(1,235)
Total assets less current liabilities	24,756	95,777	124,511	(132,220)	112,824
Noncurrent liabilities					
Finance debt			11,922		11,922
Other payables	10,586	98	30,491	(37,720)	3,455
Provisions for liabilities and charges					
Deferred taxation	1,686		11,828		13,514
Other	489	142	13,255		13,886
Net assets	11,995	95,537	57,015	(94,500)	70,047
Minority shareholders interest equity			638		638
BP Shareholders interest	11,995	95,537	56,377	(94,500)	69,409

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 49 Condensed consolidating information on certain US Subsidiaries (continued)

Balance Sheet (concluded)

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
	($ million)				
At December 31, 2002					
Capital and reserves					
Capital shares	1,903	5,616		(1,903)	5,616
Paid in surplus	3,145	4,243		(3,145)	4,243
Merger reserve		26,336	697		27,033
Other reserves		173			173
Retained earnings	6,947	59,169	55,680	(89,452)	32,344
	11,995	95,537	56,377	(94,500)	69,409

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	11,995	95,537	56,377	(94,500)	69,409
Adjustments:					

Deferred taxation/business combinations	74	(78)	(152)	78	(78)
Provisions	(190)	(1,088)	(902)	1,092	(1,088)
Sale and leaseback		(106)	(106)	106	(106)
Goodwill		(84)	(84)	84	(84)
Derivative financial instruments	(50)	(135)	(135)	185	(135)
Gain arising on asset exchange		142	142	(142)	142
Ordinary shares held for future awards to employees		(159)			(159)
Dividends		1,398			1,398
Investments		34	34	(34)	34
Additional minimum pension liability		(2,164)	(2,164)	2,164	(2,164)
Other		(48)	(48)	48	(48)
BP Shareholders interest as adjusted to accord with US GAAP	11,829	93,249	52,962	(90,919)	67,121

F - 121

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 49 Condensed consolidating information on certain US Subsidiaries (continued)

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, 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)	(1,747)		(6,187)
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	(1,735)		1,342
Financing	1,243	1,826	(2,003)		1,066
Management of liquid resources			(41)		(41)
Increase (decrease) in cash	6	2	309		317
	1,249	1,828	(1,735)		1,342

The consolidated statement of cash flows presented in accordance with SFAS 95 is as follows:

	Issuer	Guarantor	
		BP p.l.c.	BP Group

	BP Exploration (Alaska) Inc		Other subsidiaries	Eliminations and reclassifications	
			($ 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)	(5,303)	(207)	(9,925)
Net cash provided by (used in) financing activities	(1,300)	(7,481)	(25,929)	27,970	(6,740)
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

F - 122

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 49 Condensed consolidating information on certain US Subsidiaries (continued)

Cash flow statement (continued)

	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)	151	(8,700)		(9,646)
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	558	(1,085)		(344)
Financing	165	560	(906)		(181)
Management of liquid resources			(220)		(220)
Increase (decrease) in cash	18	(2)	41		57
	183	558	(1,085)		(344)

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)	(4,279)	(10,052)	4,345	(11,083)
Net cash provided by (used in) financing activities	(192)	(5,825)	120	774	(5,123)
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

Table of Contents

BP p.l.c. AND SUBSIDIARIES

NOTES TO FINANCIAL STATEMENTS (Concluded)

Note 49 Condensed consolidating information on certain US Subsidiaries (concluded)

Cash flow statement (concluded)

	Issuer	Guarantor			
	BP Exploration (Alaska) Inc	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP Group
	($ million)				
Year ended December 31, 2001					
Net cash inflow (outflow) from operating activities	956	6,199	18,249	(2,995)	22,409
Dividends from joint ventures			104		104
Dividends from associated undertakings			528		528
Dividends from subsidiaries		1,537		(1,537)	
Net cash inflow (outflow) from servicing of finance and returns on investments		1,218	(2,166)		(948)
Tax paid	(345)	(1)	(4,314)		(4,660)
Net cash inflow (outflow) for capital expenditure and financial investment	(1,870)	(33)	(7,946)		(9,849)
Net cash outflow for acquisitions and disposals		(2,995)	(1,755)	2,995	(1,755)
Equity dividends paid		(4,827)	(1,537)	1,537	(4,827)
Net cash inflow (outflow)	(1,259)	1,098	1,163		1,002
Financing	(1,262)	1,097	1,137		972
Management of liquid resources			(211)		(211)
Increase in cash	3	1	237		241
	(1,259)	1,098	1,163		1,002

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	611	8,953	12,401	(4,397)	17,568
Net cash provided by (used in) investing activities	(1,870)	(3,028)	(9,701)	2,914	(11,685)
Net cash provided by (used in) financing activities	1,262	(5,924)	(2,674)	1,483	(5,853)
Currency translation differences relating to cash and cash equivalents			(53)		(53)
Increase (decrease) in cash and cash equivalents	3	1	(27)		(23)
Cash and cash equivalents at beginning of year	(32)	2	1,861		1,831
Cash and cash equivalents at end of year	(29)	3	1,834		1,808

Table of Contents

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, 2003, 2002 and 2001.

Movements in estimated net proved reserves of crude oil (a)

	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 (b)	53	42	(83)	(33)	30	(253)		(107)	(351)
Purchases of reserves-in-place				42					42
Extensions, discoveries and other additions (b)	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									
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 (c)	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									
Developed				206	1		1,384	705	2,296
Undeveloped				134			410	27	571
				340	1		1,794	732	2,867

S - 1

Table of Contents

BP p.l.c. AND SUBSIDIARIES

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)

(Unaudited)

Movements in estimated net proved reserves of crude oil (a) **(continued)**

	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									
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 (c)	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

Table of Contents

BP p.l.c. AND SUBSIDIARIES

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)

(Unaudited)

Movements in estimated net proved reserves of crude oil (a) **(continued)**

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
				(millions of barrels)					
2001									
Subsidiary undertakings									
At January 1									
Developed	1,138	213	2,150	365	109	208		135	4,318
Undeveloped	254	160	1,043	309	71	287		66	2,190
	1,392	373	3,193	674	180	495		201	6,508
Changes attributable to:									
Revisions of previous estimates	(16)	16	(39)	(86)	6	16		6	(97)
Purchases of reserves-in-place	9			10	1				20
Extensions, discoveries and other additions	94		641	52	2	182		316	1,287
Improved recovery	24	29	48	8		4			113
Production	(177)	(37)	(243)	(61)	(24)	(39)		(20)	(601)
Sales of reserves-in-place	(1)		(11)	(1)					(13)
	(67)	8	396	(78)	(15)	163		302	709
At December 31									
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 (c)	596	165	658		503	7,217
Equity-accounted entities (BP share)									
At January 1									
Developed				116	3		19	848	986
Undeveloped	5			111	7			26	149
	5			227	10		19	874	1,135
Changes attributable to:									
Revisions of previous estimates				22	1		33	(1)	55
Purchases of reserves-in-place									

Extensions, discoveries and other additions				24					24
Improved recovery				21					21
Production				(19)	(2)		(7)	(48)	(76)
Sales of reserves-in-place									
				48	(1)		26	(49)	24
At December 31									
Developed	5			129	3		45	800	982
Undeveloped				146	6			25	177
	5			275	9		45	825	1,159

S - 3

Table of Contents

BP p.l.c. AND SUBSIDIARIES

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)

(Unaudited)

Movements in estimated net proved reserves of crude oil (a) **(concluded)**

(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 year ended December 31, 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 prior years have not been adjusted.

(c) Proved reserves in the Prudhoe Bay field in Alaska include an estimated 78 million barrels (86 million barrels at December 31, 2002 and 43 million barrels at December 31, 2001) 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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)

(Unaudited)

Movements in estimated net proved reserves of natural gas (a)

	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 (b)	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	(528)	(43)	(1,224) (c)	(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									
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 (b)				437	26		107	(21)	549
Purchases of reserves-in-place									

Extensions, discoveries and other additions				12					12
Improved recovery				35					35
Production				(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

S - 5

Table of Contents

BP p.l.c. AND SUBSIDIARIES

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)

(Unaudited)

Movements in estimated net proved reserves of natural gas (a) **(continued)**

	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	(566)	(54)	(1,334) (c)	(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									
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	(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

Table of Contents

BP p.l.c. AND SUBSIDIARIES

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)

(Unaudited)

Movements in estimated net proved reserves of natural gas (a) **(continued)**

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
				(billions of cubic feet)					
2001									
Subsidiary undertakings									
At January 1									
Developed	3,898	275	12,111	4,755	2,291	518		421	24,269
Undeveloped	1,058	71	2,400	8,868	2,085	2,237		112	16,831
	4,956	346	14,511	13,623	4,376	2,755		533	41,100
Changes attributable to:									
Revisions of previous estimates	(25)	(10)	16	(840)	103	12		18	(726)
Purchases of reserves-in-place	14		2		102				118
Extensions, discoveries and other additions	70	15	620	2,157	255	1,334		2	4,453
Improved recovery	136	11	988	121		3		8	1,267
Production	(625)	(54)	(1,358) (c)	(586)	(309)	(69)		(86)	(3,087)
Sales of reserves-in-place	(154)		(12)						(166)
	(584)	(38)	256	852	151	1,280		(58)	1,859
At December 31									
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
Equity-accounted entities									
(BP share)									
At January 1									
Developed				1,049	168			51	1,268
Undeveloped	25			991	501			33	1,550
	25			2,040	669			84	2,818
Changes attributable to:									
Revisions of previous estimates	(1)			74	1			18	92
Purchases of reserves-in-place									

Extensions, discoveries and other additions				360					360
Improved recovery				71					71
Production				(99)	(26)				(125)
Sales of reserves-in-place									
	(1)			406	(25)			18	398
At December 31									
Developed	24			1,288	153			67	1,532
Undeveloped				1,158	491			35	1,684
	24			2,446	644			102	3,216

S - 7

Table of Contents

BP p.l.c. AND SUBSIDIARIES

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)

(Unaudited)

Movements in estimated net proved reserves of natural gas (a) **(concluded)**

(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 year ended December 31, 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 prior years have not been adjusted.

(c) Includes 69 billion cubic feet of natural gas consumed in Alaskan operations (2002, 63 billion cubic feet and 2001, 61 billion cubic feet).

Table of Contents

BP p.l.c. AND SUBSIDIARIES

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)

(Unaudited)

The following tables show the differences on a regional basis between the proved reserve estimates included in this report on Form 20-F and the reserves estimated by the Company under the UK SORP and included in its 2003 Annual Report and Accounts and is provided as supplemental information for investors.

Crude oil	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
	(millions of barrels)								
Subsidiary undertakings									
Reserves at December 31, 2003	942	363	3,401	739	163	822		784	7,214
Reserves reported in the 2003 UK Annual Report and Accounts	894	318	3,238	744	166	1,173		916	7,449
Difference	48	45	163	(5)	(3)	(351)		(132)	(235)
Equity-accounted entities									
Reserves at December 31, 2003				340	1		1,794	732	2,867
Reserves reported in the 2003 UK Annual Report and Accounts				340	1		1,794	732	2,867
Difference									

Natural gas	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
	(billions of cubic feet)								
Subsidiary undertakings									
Reserves at December 31, 2003	4,091	1,517	14,819	15,743	5,002	2,828		1,155	45,155
Reserves reported in the 2003 UK Annual Report and Accounts	3,490	1,425	13,837	16,571	4,911	2,679		1,063	43,976
Difference	601	92	982	(828)	91	149		92	1,179
Equity-accounted entities									
Reserves at December 31, 2003				2,507	216		60	86	2,869
Reserves reported in the 2003 UK Annual Report and Accounts				2,260	207			86	2,553
Difference				247	9		60		316

Table of Contents

BP p.l.c. AND SUBSIDIARIES

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)

(Unaudited)

Net proved reserves at December 31, 2003 (concluded)

Total hydrocarbons (b)	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
	(millions of barrels of oil equivalent)								
Subsidiary undertakings									
Reserves at December 31, 2003	1,647	625	5,956	3,453	1,025	1,310		983	14,999
Reserves reported in the 2003 UK Annual Report and Accounts	1,496	564	5,624	3,601	1,012	1,635		1,099	15,031
Difference(a)	151	61	332	(148)	13	(325)		(116)	(32)
Equity-accounted entities									
Reserves at December 31, 2003				772	38		1,805	747	3,362
Reserves reported in the 2003 UK Annual Report and Accounts				729	37		1,794	747	3,307
Difference (a)				43	1		11		55

(a) On an aggregate basis the differences between the reserves reported in this Form 20-F to the 2003 UK Annual Report and Accounts is an additional 23 million barrels of oil equivalent.

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

Table of Contents

BP p.l.c. AND SUBSIDIARIES

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)

(Unaudited)

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves

The following tables set out the standardized measures of discounted future net cash flows, and changes therein, relating to crude oil and natural gas production from the Group s estimated proved reserves. This information is prepared in compliance with the requirements of FASB Statement of Financial Accounting Standards No. 69 Disclosures about Oil and Gas Producing Activities .

In 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.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)

(Unaudited)

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves (continued)

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
	($ million)								
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	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	11,300	1,600	35,500	11,000	4,100	8,100		4,900	76,500
At December 31, 2001									
Future cash inflows (a)	40,600	8,000	83,700	35,900	13,500	22,200		9,800	213,700
Future production cost (b)	16,900	2,900	25,200	8,000	4,000	5,700		2,400	65,100
Future development cost (b)	1,900	600	8,500	2,900	2,000	4,300		1,300	21,500
Future taxation (c)	5,700	3,000	16,900	12,200	2,500	2,700		1,500	44,500
Future net cash flows	16,100	1,500	33,100	12,800	5,000	9,500		4,600	82,600
10% annual discount (d)	5,300	400	16,600	6,300	1,800	5,400		2,300	38,100
	10,800	1,100	16,500	6,500	3,200	4,100		2,300	44,500

Standardized measure of discounted future net cash flows									

S - 12

Table of Contents

BP p.l.c. AND SUBSIDIARIES

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)

(Unaudited)

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves (concluded)

The following are the principal sources of change in the standardized measure of discounted future net cash flows during the years ended December 31, 2003, 2002 and 2001:

	Years ended December 31,		
	2003	2002	2001
		($ million)	
Sales and transfers of oil and gas produced, net of production costs	(22,200)	(22,400)	(17,500)
Development costs incurred during the year	6,300	7,200	6,800
Extensions, discoveries and improved recovery, less related costs	8,700	9,700	9,200
Net changes in prices and production cost (e)	7,300	51,600	(74,100)
Revisions of previous reserve estimates	(3,000)	2,500	(1,300)
Net change in taxation	6,100	(16,700)	26,300
Future development costs	(1,600)	(5,100)	(3,200)
Net change in purchase and sales of reserves-in-place	(5,300)	800	(200)
Addition of 10% annual discount	7,700	4,400	8,900
Total change in the standardized measure during the year	4,000	32,000	(45,100)

(a) The year end marker prices used were Brent $30.10/bbl, Henry Hub $5.76/mmbtu (2002 Brent $30.38/bbl, Henry Hub $4.13/mmbtu; 2001 Brent $19/bbl, Henry Hub $2.72/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) Net changes in prices and production costs includes the effect of exchange movements.

Equity-accounted entities

In addition, at December 31, 2003 the Group s share of the standardized measure of discounted future net cash flows of equity-accounted entities amounted to $12,000 million ($4,300 million at December 31, 2002 and $3,400 million at December 31, 2001).

Table of Contents

BP p.l.c. AND SUBSIDIARIES

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)

(Unaudited)

Operational and statistical information

The following tables present operational and statistical information related to production, drilling, productive wells and acreage.

Crude oil and natural gas production

The following table shows crude oil and natural gas production for the years ended December 31, 2003, 2002 and 2001.

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total (d)
	(thousand barrels per day)								
Production for the year (a)									
Crude oil (b) (d)									
2003	377	84	726	257	61	117	303	196	2,121
2002	462	104	765	237	75	124	80	171	2,018
2001	485	100	744	222	66	106	20	188	1,931
	(million cubic feet per day)								
Natural gas (c)(e)									
2003	1,446	119	3,128	2,480	848	253	136	203	8,613
2002	1,555	147	3,483	2,082	932	256	18	234	8,707
2001	1,713	147	3,554	1,875	919	189		235	8,632

(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.

(d) Includes amounts produced for the Group by equity-accounted entities of 506,000 b/d in 2003 (2002, 252,000 b/d and 2001, 208,000 b/d).

(e) Includes amounts produced for the Group by equity-accounted entities of 521 mmcf/d in 2003 (2002, 383 mmcf/d and 2001, 345 mmcf/d).

Table of Contents

BP p.l.c. AND SUBSIDIARIES

SUPPLEMENTARY OIL AND GAS INFORMATION (Continued)

(Unaudited)

Operational and statistical information (continued)

Productive oil and gas wells and acreage

The following tables show the number of gross and net productive oil and natural gas wells and total gross and net developed and undeveloped oil and natural gas acreage in which the Group and its equity-accounted entities had interests as of December 31, 2003. 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	Other	Total
Number of productive wells at December 31, 2003										
Oil wells (a)	gross	452	66	5,309	3,255	331	460	16,218	1,260	27,351
	net	146.5	18.1	2,932.5	1,819.6	144.0	417.7	8,109.0	174.9	13,762.3
Gas wells (b)	gross	460	42	17,721	2,191	508	80	30	114	21,146
	net	148.6	15.0	10,755.8	1,349.4	194.6	53.8	14.5	47.5	12,579.2

(a) Includes approximately 1,156 gross (378.2 net) multiple completion wells (more than one formation producing into the same well bore).

(b) Includes approximately 2,147 gross (1,100.1 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	Other	Total
					(thousands of acres)				
Oil and natural gas acreage at December 31, 2003									
Developed									
gross	748	132	7,620	2,617	686	1,272	3,196	1,627	17,898

net	216.3	42.7	5,008.2	1,313.1	222.9	661.5	1,598.0	174.4	9,237.1
Undeveloped (a)									
gross	2,660	3,311	7,848	25,082	24,108	16,451	5,174	16,942	101,576
net	1,395.2	1,077.5	5,377.6	14,123.8	10,108.8	7,829.5	1,886.4	3,966.8	45,765.6

(a) Undeveloped acreage includes leases and concessions.

Table of Contents

BP p.l.c. AND SUBSIDIARIES

SUPPLEMENTARY OIL AND GAS INFORMATION (Concluded)

(Unaudited)

Operational and statistical information (concluded)

Net oil and gas wells completed or abandoned

The following table shows the number of net productive and dry exploratory and development oil and natural gas wells completed or abandoned in the years indicated by the Group and its equity-accounted entities. Productive wells include wells in which hydrocarbons were encountered and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well is one found to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
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
2001									
Exploratory									
productive	3.2	0.9	5.7	3.0	6.1	6.9	1.9	0.8	28.5
dry	1.2	0.7	3.8	0.7		1.0	0.6	0.2	8.2
Development									
productive	13.5	4.2	705.3	257.1	33.4	16.7	9.3	8.7	1,048.2
dry	1.6		25.7	32.6			0.6	0.3	60.8

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, 2003. 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	Other	Total
At December 31, 2003									
Exploratory									
gross			15	1	5	2	4	2	29
net			7.1	0.3	2.6	0.9	2.0	0.3	13.2
Development									
gross	9	4	151	14	1	11	151	173	514
net	2.8	1.1	90.0	7.8		6.5	75.5	7.2	190.9

Table of Contents

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)				
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
2001					
Fixed assets Investments (b)	505	68	(4)	63	632
Doubtful debts (b)	357	131	17	(215)	290

(a) Principally currency transactions.

(b) Deducted in the balance sheet from the assets to which they apply.

Table of Contents

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 annual report on its behalf.

BP p.l.c.
(Registrant)

/s/ D. J. PEARL

D. J. Pearl
Deputy Company Secretary

Dated: June 28, 2004