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

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

(Mark One)

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

OR

[X] **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2004

OR

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

OR

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

Commission file number 1-6262

BP p.l.c.

(Exact name of Registrant as specified in its charter)

ENGLAND and WALES

(Jurisdiction of incorporation or organization)

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

(Address of principal executive offices)

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

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

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

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

None

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

None

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

Ordinary Shares of 25c each	**21,525,977,902**
Cumulative First Preference Shares of £1 each	**7,232,838**
Cumulative Second Preference Shares of £1 each	**5,473,414**

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

Yes X No ____

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

Yes ____ No X

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

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

Yes X No ____

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

Large accelerated filer X Accelerated filer ____ Non-accelerated filer ____

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

Item 17 ____ Item 18 X

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

Yes ____ No X

EXPLANATORY NOTE

Introduction

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

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

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

Revenues and Cost of Sales Restatement

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

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

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

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

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 Securities and Exchange Commission (SEC) in Rule 4-10(a) of Regulation S-X, paragraphs (2), (2i), (2ii) and (2iii). Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

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

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

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

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

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

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

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

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

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

Miscellaneous terms

'ADR' American Depositary Receipt.

'ADS' American Depositary Share.

'Amoco' The former Amoco Corporation and its subsidiaries.

'Atlantic Richfield' Atlantic Richfield Company and its subsidiaries.

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

'Barrel' 42 US gallons.

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

'Burmah Castrol' Burmah Castrol plc and its subsidiaries.

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

The 'Company' BP p.l.c.

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

'Dollar' or '$' The US dollar.

'FSA' Financial Services Authority.

'Gas' Natural Gas.

'Hydrocarbons' Crude oil and natural gas.

'IFRS' International Financial Reporting Standards.

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

'LNG' Liquefied Natural Gas.

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

'LPG' Liquefied Petroleum Gas.

'mmbtu' million British thermal units.

'MTBE' Methyl Tertiary Butyl Ether.

'NGL' Natural Gas Liquid.

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

'OECD' Organization for Economic Cooperation and Development.

'OPEC' The Organization of Petroleum Exporting Countries.

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

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

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

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

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

'Tonne' 2,204.6 pounds.

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

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

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

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

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

PART I

ITEM 1 IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISORS

Not applicable.

ITEM 2 OFFER STATISTICS AND EXPECTED TIMETABLE

Not applicable.

ITEM 3 KEY INFORMATION

SELECTED FINANCIAL INFORMATION

Summary

This information has been extracted or derived from the audited financial statements of the BP Group presented elsewhere herein or otherwise included with BP p.l.c.'s Annual Reports on Form 20-F for the relevant years which have been filed with the Securities and Exchange Commission, as reclassified to conform with the accounting presentation adopted in this annual report. The financial information for 2002 and 2003 has been restated to reflect the adoption by the Group of Financial Reporting Standard No. 17 'Retirement Benefits' (FRS 17) with effect from January 1, 2004. The financial information for 2000 and 2001 has not been restated for FRS 17. The financial information for 2000 to 2003 has been restated to reflect the adoption by the Group of Urgent Issues Task Force Abstract No. 38 'Accounting for Employee Share Ownership Plan (ESOP) Trusts with effect from January 1, 2004.

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

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

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

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

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

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

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

Dividends

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

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

The following table shows dividends announced by the Company per ADS for each of the past five years before the 'refund' and deduction of withholding taxes as described in Item 10 Additional Information Taxation on page 164. Refund means an amount equal to the tax credit available to individual shareholders resident in the UK in respect of such dividend, less a withholding tax equal to 15% (but limited to the amount of the tax credit) of the aggregate of such tax credit and such dividend.

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

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

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

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

Future dividends will be dependent upon future earnings, the financial condition of the Group, the Risk Factors set out below, and other matters which may affect the business of the Group set out in Item 5 Operating and Financial Review on page 83.

RISK FACTORS

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

External Risks

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

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

Price Risk: Oil prices are subject to international supply and demand. Political developments (especially in the Middle East) and the outcome of meetings of OPEC can particularly affect world supply and oil prices. In addition to the adverse effect on revenues, margins and profitability from any future fall in oil and natural gas prices, a prolonged period of low prices or other indicators would lead to a review for impairment of the BP Group's oil and natural gas properties. This review would reflect management's view of long-term oil and natural gas prices. Such a review could result in a charge for impairment which could have a significant effect on the BP Group's results of operations in the period in which it occurs.

Regulatory Risks: The oil industry is subject to regulation and intervention by governments throughout the world in such matters as the award of exploration and production interests, the imposition of specific drilling obligations, environmental protection controls, controls over the development and decommissioning of a field (including restrictions on production) and, possibly, nationalization, expropriation, cancellation or non-renewal of contract rights. The oil industry is also subject to the payment of royalties and taxation, which tend to be high compared with those payable in respect of other commercial activities and operates in certain tax jurisdictions which have a degree of uncertainty relating to the interpretation of, and changes to, tax law. As a result of new laws and regulations or other factors, we could be required to curtail or cease certain operations, causing our production to decrease, or we could incur additional costs.

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

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

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

Reputational Risks

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

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

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

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

Operational Risks

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

Drilling and Production Risk: Exploration and production require high levels of investment and have particular economic risks and opportunities. They are subject to natural hazards and other uncertainties, including those relating to the physical characteristics of an oil or natural gas field. The cost of drilling, completing or operating wells is often uncertain. We may be required to curtail, delay or cancel drilling operations because of a variety of factors including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, adverse weather conditions and compliance with governmental requirements.

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

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

FORWARD LOOKING STATEMENTS

In order to utilize the 'Safe Harbor' provisions of the United States Private Securities Litigation Reform Act of 1995, BP is providing the following cautionary statement. This document contains certain forward-looking statements with respect to the financial condition, results of operations and businesses of BP and certain of the plans and objectives of BP with respect to these items. These statements may generally, but not always, be identified by the use of words such as 'will', 'expects', 'is expected to', 'should', 'may', 'is likely to', 'intends', 'believes', 'plans', 'we see' or similar expressions. In particular, among other statements, (i) certain statements in Item 4 Information on the Company and Item 5 Operating and Financial Review with regard to management aims and objectives, future capital expenditure, future hydrocarbon production volume, date or period(s) in which production is scheduled or expected to come on stream or a project or action is scheduled or expected to be completed, capacity of planned plants or facilities and impact of health, safety and environmental regulations; (ii) the statements in Item 4 Information on the Company with regard to planned expansion, investment or other projects and future regulatory actions; and (iii) the statements in Item 5 Operating and Financial Review with regard to the plans of the Group, cash flows, opportunities for material acquisitions, the cost of future remediation programmes, liquidity and costs for providing pension and other postretirement benefits; and including under 'Liquidity and Capital Resources' with regard to future cash flows, future levels of capital expenditure and divestments, working capital, the renewal of borrowing facilities, shareholder distributions and share buybacks and expected payments under contractual and commercial commitments; under 'Outlook' with regard to global and certain regional economies, oil and gas prices and realizations, expectations for supply and demand, refining and marketing margins; are all forward-looking in nature.

By their nature, forward-looking statements involve risk and uncertainty because they relate to events and depend on circumstances that will or may occur in the future and are outside the control of BP. Actual results may differ materially from those expressed in such statements, depending on a variety of factors, including the specific factors identified in the discussions accompanying such forward-looking statements; the timing of bringing new fields on stream; future levels of industry product supply, demand and pricing; operational problems; general economic conditions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations; exchange rate fluctuations; development and use of new technology; the success or otherwise of partnering; the actions of competitors; natural disasters and adverse weather conditions; changes in public expectations and other changes to business conditions; wars and acts of terrorism or sabotage; and other factors discussed elsewhere in this report including under 'Risk Factors' above. In addition to factors set forth elsewhere in this report, the factors set forth above are important factors, although not exhaustive, that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

STATEMENTS REGARDING COMPETITIVE POSITION

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

ITEM 4 INFORMATION ON THE COMPANY

GENERAL

Unless otherwise indicated, information in this Item reflects 100% of the assets and operations of the Company and its subsidiaries which were consolidated at the date or for the periods indicated, including minority interests. Also, unless otherwise indicated, figures for business turnover include sales between BP businesses.

BP was created on December 31, 1998 by the merger of Amoco Corporation, incorporated in Indiana, USA, in 1889, and The British Petroleum Company p.l.c., registered in 1909 in England and Wales. The resulting company, BP p.l.c., is a public limited company, registered in England and Wales.

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

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

Our agent in the USA is:

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

Overview of the Group

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

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

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

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

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

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

In Refining and Marketing, we have a strong presence in the USA. We market under the Amoco and BP brands in the Midwest, East, and Southeast, and under the ARCO brand on the West Coast. In Europe we have a strong retail position and increased our presence in 2002 by acquiring Veba Oil (Veba). The Veba transaction expanded our refining position in Germany and our marketing position in Germany and Central Europe. Veba markets gasoline under the Aral brand, which is now our principal retail brand in Germany and in the Czech Republic. We have established or are growing businesses elsewhere in the world under the BP brand.

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

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

Acquisitions and Disposals

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

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

As a condition of regulatory approval of the deal, BP was required to dispose of 4% of the combined 26.5% retail market share of BP and Aral in Germany, 45% of its stake in the Bayernoil refinery, two of its three shareholdings in the ARG ethylene pipeline, and to make it possible for a new entrant to supply aviation fuel on competitive terms at Frankfurt airport. During 2003, BP fully complied with the conditions imposed.

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

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

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

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

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

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

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

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

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

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

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

Resegmentation in 2005

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

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

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

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

Financial and Operating Information

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

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

*

After minority shareholders' interest

(a)

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

(b)

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

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

Information for 2004, 2003 and 2002 concerning the profits and assets attributable to the businesses and to the geographical areas in which the Group operates is set forth in Item 18 Financial Statements Note 49 on page F-99.

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

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

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

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

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

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

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

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

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

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

SEGMENTAL INFORMATION

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

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

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

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

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

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

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

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

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

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

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

EXPLORATION AND PRODUCTION

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

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

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

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

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

(c) Crude oil and natural gas liquids.

(d)

Henry Hub First of Month Index.

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

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

The Exploration and Production strategy is to:

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

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

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

Upstream Activities

Exploration

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

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

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

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

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

In 2004, we were involved in discoveries in Angola, Egypt, Trinidad, Russia and the USA. In most cases, reserve bookings from these fields will depend on the results of ongoing technical and commercial evaluations, including appraisal drilling. Our 2004 discoveries included the following:

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

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

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

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

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

Reserves and Production

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

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

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

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

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

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

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

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

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

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

Details of our net proved reserves of crude oil, condensate, natural gas liquids and natural gas at December 31, 2004, 2003, and 2002 and reserves changes for each of the three years then ended are set out in the Supplementary Oil and Gas Information section in Item 18 Supplementary Oil and Gas Information beginning on page S-1. We separately disclose our share of reserves held in equity-accounted companies (joint ventures and associated companies) although we do not control these entities or the assets held by such entities.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(a)

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

(b)

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

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

(c)

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

(d)

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

(e)

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

(f)

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

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

Liquids

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

*

BP operated.

BP operates the majority of the fields in this area.

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

* BP operated.

Natural gas

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

* BP operated.

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

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

* BP operated

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

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

(c)

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

(d)

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

United States

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

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

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

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

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

Deepwater Gulf of Mexico

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

Significant events included:

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

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

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

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

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

Gulf of Mexico Shelf

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

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

Lower 48 States

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

Production is derived primarily from two main areas:

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

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

Significant events included:

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

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

Alaska

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

Key activities in Alaska:

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

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

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

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

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

United Kingdom

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

Significant activities included the following:

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

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

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

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

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

Rest of Europe

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

Norway

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

Significant activities included the following:

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

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

Rest of World

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

Rest of Americas

Canada

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

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

Trinidad

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

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

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

Venezuela

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

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

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

Colombia

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

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

Argentina and Bolivia

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

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

Africa

Algeria

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

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

Angola

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

Activities in 2004 included the following:

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

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

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

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

Egypt

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

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

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

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

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

Asia Pacific

Indonesia

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

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

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

Vietnam

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

China

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

Australia

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

Russia

TNK-BP

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

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

TNK-BP Group Restructuring

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

Other

Middle East and Pakistan

Production in the Middle East principally consists of the production entitlement of associated undertakings in Abu Dhabi, where we have equity interests of 9.5% and 14.7% in onshore and offshore concessions, respectively. In 2004, production in Abu Dhabi was 142 mb/d, up around 3% from 2003 as a result of OPEC quota increase and strong worldwide demand.

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

Azerbaijan

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

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

Midstream Activities

Oil and Natural Gas Transportation

The Group has direct or indirect interests in certain crude oil transportation systems, the principal ones of which are the Trans Alaska Pipeline System (TAPS) in the USA and the Forties Pipelines System (FPS) in the UK sector of the North Sea. We also operate the Central Area Transmission System (CATS) for natural gas in the UK sector of the North Sea.

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

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

Activity in oil and natural gas transportation during 2004 included:

Alaska

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

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

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

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

The use of US-built and US-flagged ships is required when transporting Alaskan oil to markets in the USA. BP has begun replacing its US-flagged fleet as existing ships are retired in accordance with the Oil Pollution Act of 1990. For discussion of the Oil Pollution Act of 1990, see Environmental Protection Maritime Oil Spill Regulations in this Item on page 75. BP has contracted for the delivery of four 1.3 million-barrel-capacity, double-hull tankers for use in transporting North Slope oil to West Coast refineries. The ships are being constructed by the National Steel and Shipbuilding Company in San Diego, CA. BP took delivery of the first of the four state-of-the-art double-hull tankers, the Alaskan Frontier, in August, 2004 and the second, the Alaskan Explorer, in March 2005. The third is expected to be delivered in the fourth quarter of 2005 and the fourth in 2006. In addition to the Alaskan Frontier and Explorer, BP America Inc. has a chartered fleet of seven US-flagged tankers to transport Alaskan crude oil to markets.

North Sea

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

BP operates and has a 29.5% interest in CATS, a 400-kilometre natural gas pipeline system in the central UK sector of the North Sea. The pipeline has a transportation capacity of 1.7 bcf/d to a natural gas terminal at Teesside in northeast England. CATS offers natural gas transportation services or transportation and processing via two 600 mmcf/d processing trains. In 2004, throughput was 1.4 bcf/d (gross), 405mcf/d (net).

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

Asia (including the former Soviet Union)

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

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

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

Gulf of Mexico

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

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

Liquefied Natural Gas

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

Significant activity during 2004 included the following:

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

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

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

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

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

REFINING AND MARKETING

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

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

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

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

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

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

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

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

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

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

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

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

Resegmentation in 2005

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

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

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

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

Texas City Refinery

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

Refining

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

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

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

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

* Indicates refineries operated by BP.

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

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

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

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

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

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

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

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

Marketing

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

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

(a) Excludes sales to other BP businesses.

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

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

(d) Trading/supply sales are to large unbranded resellers and other oil companies.

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

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

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

In marketing, our aim is to increase total margin by focusing on both volumes and margin per unit. We do this by growing our customer base, both in existing and new markets, by attracting new customers and by covering a wider geographic area. We also work to improve the efficiency of our operations through reducing the cost of goods sold and improving our product mix. In addition, we recognize that our customers are demanding a wider choice of fuels, particularly fuels that are cleaner and more efficient. Through our integrated refining and marketing operations, we believe we are better able to meet these customer demands.

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

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

Retail

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

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

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

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

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

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

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

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

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

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

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

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

Lubricants

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

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

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

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

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

Business to Business Marketing

Business to Business Marketing encompasses marketing a comprehensive range of products to other businesses. This business aims to build relationships with customers that not only purchase a wide variety of products in large quantities but also additional services. Interfaces with Retail, Refining and Logistics play a crucial role in this business. We aim to attract more customers through innovation in multi-product offers and cleaner fuels, packaged with a range of value-added services and solutions.

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

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

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

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

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

Supply and Trading

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

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

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

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

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

(a) Exchange traded commodity derivatives

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

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

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

(c)

Over-the-counter forward contracts

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

(d)

Spot and term contracts

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

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

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

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

Transportation

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

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

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

Shipping

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

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

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

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

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

PETROCHEMICALS

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

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

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

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

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

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

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

Significant investment activities during 2004:

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

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

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

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

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

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

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

Significant divestment activities during 2004:

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

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

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

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

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

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

Manufacturing Facilities

BP has large-scale manufacturing facilities in Europe and the USA. The Group's major sites, with our share of their capacities, are: Grangemouth (3,045 ktepa) and Hull (1,535 ktepa) in the UK; Lavéra (1,940 ktepa) in France; Marl (635 ktepa), Gelsenkirchen (1,455 ktepa) and Köln (4,615 ktepa) in Germany; Geel (2,045 ktepa) in Belgium; and Texas City, Texas (2,850 ktepa), Chocolate Bayou, Texas (2,705 ktepa), Decatur, Alabama (2,250 ktepa), and Cooper River, South Carolina (1,335 ktepa) in the USA.

We aim to grow in the Asia-Pacific region, which we believe offers good prospects for demand growth. Our intention is to build further on the positions that the Group now holds in the region through planned investment and commercial relationships, such as joint ventures. Our share of capacity in Asia amounts to 4,775 ktepa, as follows: Indonesia (245 ktepa), South Korea (1,020 ktepa), Malaysia (1,505 ktepa), Taiwan (1,250 ktepa) and China (755 ktepa). When on line in 2005, our share of the SECCO petrochemical complex in Shanghai, (BP 50%), is expected to add 1,700 ktepa of capacity.

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

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

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

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

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

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

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

Aromatics and Acetyls

Purified Terephthalic Acid

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

Major Activities

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

Paraxylene

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

Acetic Acid

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

Samsung BP Chemicals (BP 51%); in China through Yangtze River Acetyls Company (BP 51%) and in Malaysia through BP Petronas Acetyls Sdn. Bhd. (BP 70%).

Major Activities

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

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

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

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

Other Products

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

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

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

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

Olefins and Derivatives

Ethylene (and Related Co-products)

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

Olefins ethylene, propylene and butadiene are produced by crackers at Grangemouth, UK; Lavéra, France (Naphtachimie BP 50%); Köln, Germany and Chocolate Bayou, Texas in the USA. Olefins are also manufactured by Ethylene Malaysia Sdn. Bhd. (BP 15%) at Kertih, Malaysia and by BPRP at Gelsenkirchen and Munchmunster in Germany. Crackers produce the raw materials for the production of derivative products including polyethylene, polypropylene, acrylonitrile, styrene, ethanol and ethylene oxide, which are also produced at various BP plants.

Major Activities

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

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

Polypropylene

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

Major Activities

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

High Density Polyethylene

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

Major Activities

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

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

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

Acrylonitrile

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

Major Activities

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

Other Products

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

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

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

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

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

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

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

Major Activities

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

- In February 2004, we announced the closure of the last manufacturing plant at Baglan Bay, UK. Production of isopropanol ceased in March 2004.
- In May 2004, we completed the sale of our wholly owned specialty intermediate chemicals businesses including TMA, PIA and MAN.
- In October 2004, we completed the sale of our Fabrics and Fibres Business.
- In December 2004, we announced that we would close our LAO production facility in Pasadena, Texas, by the end of 2005.
- In March 2005, we completed the sale of our BDO facility at Lima, Ohio.

GAS, POWER AND RENEWABLES

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

63

Marketing and Trading Activities

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

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

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

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

(a)

Exchange traded commodity derivatives

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

(b)

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

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

(c)

OTC forward contracts

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

(d)

Spot and term contract

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

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

North America

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

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

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

United Kingdom

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

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

Rest of Europe

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

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

Natural Gas Liquids

	Years ended December 31,		
Group NGL sales volumes	**2004**	**2003**	**2002**
	(thousand barrels per day)		
UK	8	3	4
Rest of Europe	6		
USA (a)	393	329	296
Rest of World	203	205	232
Total	610	537	532
(a) Includes the following volumes under OTC forward contracts	188	32	3

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

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

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

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

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

New Market Development and LNG

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

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

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

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

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

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

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

Solar and Renewables

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

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

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

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

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

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

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

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

Other Activities

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

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

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

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

OTHER BUSINESSES AND CORPORATE

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

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

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

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

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

Investments in China. During 2000, BP made two investments in China, one of the world's fastest growing economies. BP invested $416 million in the China Petroleum and Chemical Corporation (Sinopec) and $578 million in PetroChina in the initial public offerings of both companies, obtaining around 2% in each company. During 2004 we sold these investments for aggregate proceeds of $2,360 million.

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

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

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

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

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

REGULATION OF THE GROUP'S BUSINESS

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

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

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

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

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

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

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

ENVIRONMENTAL PROTECTION

Health, Safety and Environmental Regulation

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

The extent and cost of future environmental restoration, remediation and abatement programmes are often inherently difficult to estimate. They depend on the magnitude of any possible contamination, the timing and extent of the corrective actions required and BP's share of liability relative to that of other solvent responsible parties. Though the costs of future restoration and remediation could be significant, and may be material to the results of operations in the period in which they are recognized, it is not expected that such costs will be material to the Group's overall results of operations or financial position. Refer to Item 18 Financial Statements Note 32 on page F-56 for the amounts provided in respect of environmental remediation and decommissioning.

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

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

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

For a discussion of the Group's environmental expenditures see Item 5 Operating and Financial Review Environmental Expenditure on page 97.

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

Climate Change Programmes

Kyoto Protocol

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

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

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

European Union Emissions Trading Scheme

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

Maritime Oil Spill Regulations

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

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

United States Regional Review

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

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

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

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

Throughout 2004, BP continued to comply with a plea agreement with the US Justice Department to develop, implement and maintain a nationwide environmental management system (EMS) consistent with the best environmental practices at Group facilities engaged in oil exploration, drilling and/or production in the US and its territories. BP fully implemented EMSs in Alaska and Lower 48 exploration and production performance units during 2003 and met the requirement to spend at least $15 million on the programme. The plea agreement and the associated period of organizational probation ended on January 31, 2005.

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

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

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

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

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

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

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

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

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

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

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

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

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

European Union Regional Review

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

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

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

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

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

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

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

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

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

PROPERTY, PLANTS AND EQUIPMENT

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

ORGANIZATIONAL STRUCTURE

The significant subsidiary undertakings of the Group at December 31, 2004 and the Group percentage of ordinary share capital (to nearest whole number) are set out below. The principal country of operation is generally indicated by the company's country of incorporation or by its name. Those held directly by the Company are marked with an asterisk (*), the percentage owned being that of the Group unless otherwise indicated. Refer to Item 18 Financial Statements Note 42 on page F-82 and Note 45 on page F-86 for information on significant joint ventures and associated undertakings of the Group.

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

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

ITEM 5 OPERATING AND FINANCIAL REVIEW

GROUP OPERATING RESULTS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Exceptional Items

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

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

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

Interest Expense and Other Finance Expense

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

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

Taxation

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

Business Operating Results

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

Exploration and Production

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

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

(b) Crude oil and NGL.

(c) Henry Hub First of Month Index.

(d) Net of royalties.

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

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

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

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

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

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

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

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

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

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

Refining and Marketing

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Petrochemicals

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

(a) The Chemicals Indicator Margin (CIM) is a weighted average of externally based industry product margins. It is based on market data collected by Nexant in their quarterly market analyses, which we weight based on BP's product portfolio. While it does not cover our entire portfolio, it includes a broad range of products. Among the products and businesses covered in the CIM are the olefins and derivatives, the aromatics and derivatives, LAOs, acetic acid, vinyl acetate monomers and nitriles. Not included are fabrics and fibres, PAOs, anhydrides, speciality intermediates and the remaining parts of the solvents and acetyls businesses. CIM is an environmental trend indicator. Changes in CIM are indicative of market environment trends rather than representative of the actual margins achieved by BP in any particular period.

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

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

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

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

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

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

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

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

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

Gas, Power and Renewables

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

(a) Includes marketing, trading and supply sales.

The changes in turnover are explained in more detail below:

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

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

95

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

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

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

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

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

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

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

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

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

Other Businesses and Corporate

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

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

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

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

Environmental Expenditure

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

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

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

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

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

In addition, we make provisions to meet the cost of eventual decommissioning of our oil- and gas-producing assets and related pipelines and other assets where the fair value of the asset retirement obligation can be reasonably estimated. On installation of oil or natural gas production facility a provision is established which represents the discounted value of the expected future cost of decommissioning the asset. Additionally, we undertake periodic reviews of existing provisions. These reviews take account of revised cost assumptions, changes in decommissioning requirements and any technological developments.

Provisions for environmental remediation and decommissioning are usually set up on a discounted basis, as required by Financial Reporting Standard No. 12, 'Provisions, Contingent Liabilities and Contingent Assets'. Further details of decommissioning and environmental provisions appear in Item 18 Financial Statements Note 32 on page F-56. See also Item 4 Information on the Company Environmental Protection on page 73.

Insurance

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

LIQUIDITY AND CAPITAL RESOURCES

Cash Flow

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Trend information

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

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

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

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

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

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

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

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

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

Dividends and Other Distributions to Shareholders and Gearing

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

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

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

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

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

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

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

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

Financing the Group's Activities

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

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

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

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

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

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

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

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

In addition to reported debt, BP uses conventional off balance sheet arrangements such as operating leases and borrowings in joint ventures and associated undertakings. At December 31, 2004 the Group's share of third party borrowings of joint ventures and associated undertakings was $2,821 million (2003 $2,151 million) and $1,048 million (2003 $922 million) respectively. These amounts are not reflected in the Group's debt on the balance sheet.

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

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

At December 31, 2004 contracts had been placed for authorized future capital expenditure estimated at $6,765 million. Such expenditure is expected to be financed largely by cash flow from operating activities. The Group also has access to significant sources of liquidity in the form of committed facilities and other funding through the capital markets. At December 31, 2004, the Group had available undrawn committed borrowing facilities of $4,500 million ($3,700 million at December 31, 2003).

Contractual Commitments

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

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

(a) Expected payments exclude interest payments on borrowings.

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

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

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

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

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

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

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

Liquidity Risk

Liquidity risk is the risk that suitable sources of funding for the Group's business activities may not be available. The Group has long-term debt ratings of Aa1 and AA+ assigned respectively by Moody's and Standard & Poor's.

The Group has access to a wide range of funding at competitive rates through the capital markets and banks. It co-ordinates relationships with banks, borrowing requirements, foreign exchange requirements and cash management centrally. The Group believes it has access to sufficient funding, including through the commercial paper markets, and also has undrawn committed borrowing facilities to meet currently foreseeable borrowing requirements. At December 31, 2004, the Group had substantial amounts of undrawn borrowing facilities available, including committed facilities of $4,500 million expiring in 2005 ($3,700 million expiring in 2004). These facilities are with a number of international banks and borrowings under them would be at pre-agreed rates. The Group expects to renew the facilities on an annual basis. Certain of these facilities support the Group's commercial paper programme.

Credit Risk

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

OUTLOOK

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

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

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

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

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

CRITICAL ACCOUNTING POLICIES AND NEW ACCOUNTING STANDARDS

UK Generally Accepted Accounting Policies

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

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

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

Inherent in the application of many of the accounting policies used in the preparation of the financial statements is the need for BP management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the accounts and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from the estimates and assumptions used. The following summary provides further information about the critical accounting policies that could have a significant impact on the results of the Group and should be read in conjunction with the Notes on Accounts.

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

Accounting policy changes in 2004

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

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

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